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December 15, 2021

VIA RESS AND EMAIL

Christine Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Christine Long:

Re: Enbridge Gas Inc. ("Enbridge Gas")
Ontario Energy Board ("OEB") File No.: EB-2021-0209
2022 Federal Carbon Pricing Program Application
Interrogatory Responses and Corrected Evidence

In accordance with the OEB's Procedural Order No. 1 dated, November 17, 2021, enclosed please find the interrogatory responses of Enbridge Gas.

In the preparation of the interrogatory responses, Enbridge Gas determined that there was a correction needed to the 2022 staffing resources forecast, as well as for the methodology used to determine the portion of bad debt that is related to the Federal Carbon Pricing Program. The corrections to the evidence are outlined below and provided in this submission. For more details on the 2022 staffing resources please see the response at Exhibit I.STAFF.4, and for the bad debt methodology, please see the response at Exhibit I.VECC.7.

Exhibit	Corrected
A, Tab 2, Schedule 1 – Overview	Page 10, paragraph 22, Enbridge Gas has corrected the 2022 administrative costs; and page 19, paragraph 47, Enbridge Gas has corrected the bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for the EGD rate zone.

C – Deferral and Variance Account	Pages 3 – 4, paragraphs 8, 9 and Table 1, Enbridge Gas has corrected the 2020 administration costs; Page 6, paragraphs 17 and 19, Enbridge Gas has corrected 2020 bad debt costs; Pages 9 – 10, paragraph 24, Table 3, and paragraph 28, Enbridge Gas has corrected the forecast 2022 administration costs; and Page 12, paragraph 33, Enbridge Gas has corrected its estimate of incremental bad debt expenses in 2022.
D – Cost Recovery	Page 7, paragraph 24, Enbridge Gas has corrected the bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for the EGD rate zone.
D, Tab 1, Schedule 3	Pages 1 – 2, Enbridge Gas has corrected Table 5 and Table 6 to account for the correction to bad debt costs.
D, Tab 1, Schedule 4	Pages 3 – 5 and 7, Enbridge Gas has corrected Tables 9 – 11 to account for the correction to bad debt costs.
D, Tab 1, Schedule 5	Page 1, Enbridge Gas has corrected the General Service Rate 1 and Rate 6 impacts to account for the correction to bad debt costs.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Digitally Signed)

Richard Wathy
Technical Manager, Regulatory Applications

c.c.: T. Dyck (Enbridge Gas Counsel)
M. Parkes (OEB Staff)
L. Murray (OEB Counsel)
EB-2020-0212 (2021 FCPP Application Intervenors)

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, p. 8

Question:

In discussing the transition from the federal Output-Based Pricing System (OBPS) to the provincial Emissions Performance Standards (EPS) for eligible industrial facilities, Enbridge Gas indicates that it is still working to understand the transition plan and reserves the right to amend its application as appropriate once additional details are announced. Enbridge Gas notes certain aspects of this transition have not yet been finalized by the relevant governmental authorities and may ultimately impact the costs incurred by Enbridge Gas in complying with the Greenhouse Gas Pollution Pricing Act and EPS. Enbridge Gas further notes that any cost impacts to the Facility Carbon Charge due to a change in the estimated EPS compliance obligation will be included by Enbridge Gas in the Facility Carbon Charge – Variance Accounts for future disposition.

a) Please advise of any updates related to the transition from the OBPS to the EPS since the filing of this application. In the event there have been updates, please explain what impact they have on this application.

Response:

a) Since filing Enbridge Gas's application on September 29, 2021, the federal and Ontario governments have released further information on the registration process required for Ontario facilities to transition from the OBPS to the EPS. The EPS registration process requires the following steps:

   1. Entities must register/confirm existing registration under the Ontario EPS with the Ontario Ministry of the Environment, Conservation and Parks (MECP) to receive a Certificate of Facility Registration.
   2. Entities must then apply to Environment and Climate Change Canada ("ECCC") to obtain a Determination.
   3. Depending on the ECCC's Determination, entities must register as an emitter with the Canada Revenue Agency ("CRA") to receive an Exemption Certificate.
      - This step is only required if the ECCC's Determination, from step 2, states that the entity must re-register for exemption with the CRA. If the

ECCC's Determination approves the entity to maintain their existing CRA exemption, the entity is not required to complete step 3.

4. Entities must submit exemption documentation to their fuel supplier to receive relief from the Federal Carbon Charge on fuel deliveries.
    - If an entity was required to register with the CRA in step 3 and new exemption documentation was issued, the entity must submit the new documentation to Enbridge Gas to receive exemption from the Federal Carbon Charge. For entities that were not required to register with the CRA in step 3, no further action is required, and Enbridge Gas will maintain the customer's current exemption based on their previously submitted exemption documentation.

The pre-filed evidence stated that "Entities registered under the OBPS that will be transitioning to the EPS effective January 1, 2022 will be reissued exemption documentation from the CRA."[1] Based on the newly released registration steps as highlighted above, most of Enbridge Gas's customers transitioning from the OBPS to the EPS will not be reissued exemption documentation and their current exemption from the Federal Carbon Charge will be maintained in Enbridge Gas's billing system.

This update has no impact on Enbridge Gas's forecasted 2022 EPS compliance obligation included in the pre-filed evidence.

[1] EB-2021-0209, Exhibit A, Tab 2, Schedule 1, pages 7-8, September 29,2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, p. 9

Questions:

Enbridge Gas states that the only aspect of the FCPP that currently remains under development is the Federal GHG offset system regulations and offset protocols, which are anticipated to be completed fall of 2021.

a) Please confirm whether the Federal GHG offset system regulations and offset protocols have been completed or what the new timeline is for completion.

b) If the Federal GHG regulations and offset protocols have been completed, please explain how they will impact the FCPP going forward.

Response:

a) and b)

The Federal GHG offset system regulations and offset protocols have not yet been finalized. Enbridge Gas understands that the final regulations were expected to be published in fall 2021, but has no information regarding the latest timeline or the status of development of these regulations or the project-specific offset protocols that would also need to be published.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, p. 16

Questions:

Enbridge Gas discusses a new opportunity to reduce facility-related emissions, the development of a plan for compressor unit lifecycle replacement. Enbridge notes that as part of this long-term plan to replace identified compression, several factors are being considered in the evaluation of alternatives, including meeting the operating requirements for the storage and transmission systems, reliability, environmental compliance, and carbon reduction strategy.

a) Please provide the status on the compressor unit lifecycle replacement opportunity. Please provide any detail available on its planned implementation.

b) Please explain whether any costs related to this opportunity would be recovered through Enbridge Gas's FCPP application or through other avenues.

Response:

a) The compressor unit lifecycle replacements include named projects at the Corunna, Crowland, Waubuno and Dawn compressor stations with in-service dates planned from 2023-2026. The primary drivers for the compressor lifecycle projects are obsolescence, reliability and employee safety risks as described in Enbridge Gas's 2021 Rates Application[1] and in Enbridge Gas's 2022 Rates Application.[2] The compressor unit lifecycle replacements will be addressed in the 2023-2032 EGI Asset Management Plan which is expected to be filed with the OEB in 2022.

b) There are currently no plans to seek FCPP cost recovery for costs related to this opportunity; however, the projects will be assessed on a project specific basis.

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[1] EB-2020-0181, EGI Asset Management Plan 2021-2025, Exhibit C, Tab 2, Schedule 1, p. 196.
[2] EB-2021-0148, EGI Asset Management Plan Addendum - 2022, Exhibit B, Tab, 2, Schedule 3, p. 8.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit C, p. 5
Exhibit C, p. 9

Question:

In table 3, Enbridge Gas provided its 2022 administration costs which are forecasted to be $1.47M in 2022 for staffing. This compares to actual staffing costs of $0.84M for 2020.

a) Please provide a detailed explanation as to why Enbridge Gas is forecasting its 2022 staffing costs to increase by approximately 75% and what steps Enbridge Gas has taken to contain the growth in these costs.

Response:

During the preparation of this interrogatory response, Enbridge Gas determined that there is an error in the 2022 staffing costs shown on Table 3 in Exhibit C. The total forecast staffing costs for 2022 should be $0.94 million[1] based on 5.5 full time equivalents (FTEs).[2] This represents a 12% increase over 2020 staffing costs of $0.84 million, which was based on an average of 4.6 FTEs.[3]

Enbridge Gas is containing growth in these costs by using internal resources outside of the Carbon Strategy team, where reasonable to do so. For example, efficiencies were identified by having the Environment department complete OBPS reporting and verification, given they are accountable for other facility-related GHG reporting activities.

[1] $0.58 million for the EGD rate zone and $0.36 for the Union rate zone.
[2] As discussed in the pre-filed evidence at Exhibit C, paragraph 28, the number of FTEs increased to 5.5 in 2021, and Enbridge Gas forecasts maintaining this level of staffing in 2022.
[3] As discussed in the pre-filed evidence at Exhibit C, paragraph 14, the number of FTEs increased from 4 to 5 in May 2020.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff (STAFF)

Interrogatory

Reference:

Exhibit C, p. 8

Question:

In table 2, Enbridge Gas provided its 2020 regulated facility-related volumes/emissions and costs. The table shows that actual facility OBPS emissions in 2020 are approximately 40% lower than forecast but there is no explanation on why this is the case.

a) Please explain why actual facility OBPS emissions in 2020 were considerably lower than forecast.

Response:

a) The 2020 actual OBPS emissions were lower than 2020 forecasted emissions due to lower compressor fuel use, as a result of mild weather and lower market demand.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

Interrogatory

Reference:

Exhibit A, Tab 1, Schedule 2, para 10

Preamble:

EGI states that persons affected by the Application are the customers resident or located in the municipalities, police villages, Indigenous communities and Métis organizations served by EGI, together with those to whom EGI sells gas, or on whose behalf EGI distributes, transmits, or stores gas. [emphasis added]

Questions:

a) Please file any and all analysis EGI has performed in connection with how the Application will, or is anticipated to, affect Indigenous communities and Métis organizations, including First Nation and Métis peoples living in municipalities and police villages:

   (i) that EGI serves;
   (ii) to which EGI sells gas (e.g., Six Nations Natural Gas); and
   (iii) on whose behalf EGI distributes, transmits, or stores gas.

   If EGI has not undertaken any such analysis, please explain why no such analysis has been undertaken, in light of paragraph 10.

Response:

a) Consistent with the response to this question previously posed by Anwaatin in Enbridge Gas's 2020 Federal Carbon Pricing Program proceeding[1] and with the OEB's decision on the Applicability of Charges to Indigenous Customers,[2] the rate impacts of this Application are generic across Enbridge Gas rate classes and are applied on that basis. The *Greenhouse Gas Pollution Pricing Act*, the legislation pursuant to which Enbridge Gas is incurring costs for which it is seeking recovery in the Application, does not mandate any specific or distinct treatment for Indigenous communities and Métis organizations, and was previously considered by the OEB in

[1] EB-2019-0247, Exhibit I.Anwaatin.1, June 18, 2020.
[2] EB-2019-0247, OEB Decision and Order, September 23, 2021.

its decision on the Applicability of Charges to Indigenous Customers.[3] In that decision, the OEB also noted the *Greenhouse Gas Pollution Pricing Act* has been accompanied by a Climate Action Incentive designed to insulate affected individuals and households, including individual customers in Indigenous communities and Métis organizations, from an undue economic burden.[4]

The annual bill impacts applicable to Enbridge Gas's residential customers, including any customers in Indigenous communities and Métis organizations, are summarized at Exhibit A, Tab 2, Schedule 1, page 19. Detailed rate impacts are set out by rate class at Exhibit D, Tab 1 and Tab 2.[5]

[3] Id.
[4] Id., p. 26.
[5] Indigenous communities that are registered distributors of natural gas (e.g. Six Nations Natural Gas) and that hold an exemption certificate from the Canadian Revenue Agency ("CRA") are exempted from the Federal Carbon Charge on their Enbridge natural gas bill and are responsible for reporting their applicable volumes and remitting payment of the Federal Carbon Charge directly to CRA.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, paras 46-47.

Preamble:

The bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,400 m^3 is an increase of $47.05 per year in the EGD rate zone. The bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,200 m^3 is an increase of $43.14 per year in the Union rate zones.

The bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,400 m3 is $0.76 in the EGD rate zone. The bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,200 m3 is $0.27 in the Union South rate zone and $0.34 in the Union North rate zone.

Questions:

a) Does EGI expect that the bill impacts outlined above will be experienced by Indigenous communities? If so, please explain how such bill impacts will be experienced in Indigenous communities. If not, please explain why not.

b) Has EGI performed any analysis of the bill impact specific to Indigenous communities and peoples? If so, please provide the analysis. If not, please explain why no such analysis has been performed.

c) Has EGI quantified the rate impact of the Application on Indigenous communities and peoples? If so, please provide the quantification of the rate impact and explain how it was quantified. If not, please explain why no such quantification was performed.

d) What proportion of EGI's customers are members of Indigenous communities?

e) Has EGI analysed how Indigenous customers living on- and off-reserves will be affected by the proposed carbon charge? If so, please provide the analysis. If not, please explain why no such analysis was performed.

f) What proportion of EGI customers reside “on-reserve”, as defined in the Indian Act?

g) Can EGI identify prospective new EGI “on-reserve” communities and customers that will be served through future natural gas distribution expansions, and how the bill impacts will be experienced by those communities?

h) Has EGI considered options to assist its Indigenous customers to reduce the bill impacts of FCPP charges through, for example, an air source heat pump offering program?

Response:

a) – c)

Please see the response at Exhibit I.Anwaatin.1 a).

d) Enbridge Gas does not track the ethnicity or cultural background of its customers. However, the Company can confirm that it has approximately 3,700 customers in its billing system who are HST exempt because they reside on-reserve. This equates to approximately 0.1% of customers. Enbridge Gas currently distributes gas to 22 Indigenous communities.

e) Please see the response at Exhibit I.Anwaatin.1 a).

f) Please see response at part d) above.

g) Enbridge Gas can identify two prospective new community expansion projects for “on-reserve” communities, which were selected projects and reported on the OEB’s Report to the Minister of Energy, Northern Development and Mines and to the Associate Minister of Energy (EB-2019-0255).[1] The projects selected are the Mohawks of the Bay of Quinte[2] and Red Rock First Nation (Lake Helen Reserve)[3]. Regarding bill impacts please see the response at Exhibit I.Anwaatin.1 a).

h) Enbridge Gas has not considered options to specifically assist its Indigenous customers to reduce the bill impacts of FCPP charges through a directed heat pump offering specific to Indigenous customers. As discussed at EB-2021-0002, Exhibit I.12.EGI.Anwaatin.3 d), if the Multi-Year Demand Side Management Plan (2022 to 2027) is approved, Enbridge Gas will make reasonable efforts to maximize the reach of the Low Carbon Transition Program residential hybrid heating offering to eligible customers, which would include eligible Indigenous customers, through the development of its contractor network.

[1] EB-2019-0255, OEB Report to the Minister of Energy, Northern Development and Mines and to the Associate Minister of Energy, Potential Projects to Expand Access to Natural Gas Distribution (October 30, 2020).
[2] Ibid, p. 14.
[3] Ibid, p. 15.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedule 5
Exhibit B, Tab 2, Schedule 5

Preamble:

EGI forecasts the Total Customer-Related Costs in the EGD rate zone at $1,039,496,078.

EGI forecasts the Total Customer-Related Costs in the Union rate zone at $638,915,115.

Questions:

a) Please provide actual 2021 volumes delivered to Indigenous communities and the total customer-related costs of the Federal Carbon Charge for Indigenous communities in the EGD Rate Zone.

b) Please provide actual 2021 volumes delivered to Indigenous communities and the total customer-related costs of the Federal Carbon Charge for Indigenous communities in the Union Rate Zone.

Response:

a) and b)

Enbridge Gas no longer separately tracks the volumes and corresponding Federal Carbon Charges for First Nations on-reserve customers as per the OEB's decision on the Applicability of Charges to Indigenous Customers where it stated that, "Enbridge Gas will no longer be required to separately track these amounts for First Nations on-reserve customers, which the OEB had previously required while these rates were interim."[1]

[1] EB-2019-0247, OEB Decision and Order, September 23, 2021, p. 30.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, paras 34-41 (including Table 3)

Preamble:

EGI notes that in 2019, Enbridge Inc. implemented a Carbon and Energy Efficiency Plan (CEE Plan).

In Table 3, EGI provides estimated emissions reductions resulting from four opportunities identified to reduce facility-related emissions. EGI notes that as part of the Facility GHG Emissions Reduction project, it will continue to identify and review opportunities that reduce stationary combustion emissions (OBPS/EPS emissions) through various pathways, including electrification and RNG fuel switching (para 39).

Enbridge indicates that it will continue to identify, track and report on emission reduction opportunities using criteria that effectively balance management of its compliance obligations under the FCPP, estimated capital costs, safety and operational reliability (para 41).

Questions:

a) Please place the CEE Plan on the record in this proceeding

b) Please file all reports, presentations, analysis, data, or other materials (including drafts) related to the impact of the CEE Plan on Indigenous customers.

c) Does EGI anticipate that emissions reductions achieved in and through the CEE Plan will be used to satisfy EGI's own OBPS/EPS compliance obligations?

d) How are the costs of the CEE Plan recovered?

e) Please file all reports, presentations, analysis, data, or other materials (including drafts) related the identification and review of (i) electrification and (ii) RNG fuel switching as possible opportunities that reduce OBPS/EPS emissions.

f) Has EGI considered options for emissions-free thermal service expansion to unserved customers through the alternative of heat pumps? If so, please provide all related details and documentation.

g) Has EGI identified any other opportunities that reduce OBPS/EPS emissions other than (i) electrification and (ii) RNG fuel switching? If yes, please indicate and provide details of each identified opportunity.

h) What criteria does EGI use to effectively balance management of its compliance obligations under the FCPP, estimated capital costs, safety, and operational reliability? How are these criteria applied?

i) As part of EGI's assessment of opportunities to reduce OBPS/EPS does EGI assess the bill impacts of its facility-related emissions on its Indigenous customers? If yes, please provide details. If not, please indicate and explain why not.

Response:

a) The work being undertaken under the Facility GHG Emissions Reduction Program is a continuation of the work completed under the CEE Plan, which was not a formal document, but a plan to identify and quantify potential emission reduction opportunities. A preliminary list of emission reduction opportunities, which may reduce GHG emissions associated with Company Use or EPS Volumes was provided in Exhibit A, Tab 2, Schedule 1, Table 3. Work will continue in 2022 to develop an emissions reduction plan, which will include updating the list of opportunities and determining and/or refining costs and potential GHG reduction estimates for the identified opportunities.

b) To date, only projects that are under Enbridge Gas's standard operational maintenance program have been implemented as part of the Facility GHG Emissions Reduction Program and therefore there are no incremental cost impacts on customers, including indigenous customers.

c) The Facility GHG Emissions Reduction Program is dedicated to reducing Enbridge Gas's scope 1 and scope 2 emissions and as such, any resulting reductions in emissions (to the extent covered by the OBPS/EPS) will lower the Company's OBPS/EPS compliance obligation.

d) To date, the opportunities currently being implemented are already covered in rates, as these projects are being driven by Enbridge Gas's standard operational maintenance program. Future cost recovery will be assessed on a project specific basis.

e) Please refer to Exhibit I.EP.4 c). As this work is still in progress, the information requested cannot be filed at this time.

f) Options for emissions-free thermal service expansion to unserved customers through heat pumps are not included in the CEE Plan or Facility GHG Emissions

Reduction project, as this type of initiative would reduce end-user emissions. The purpose of the CEE Plan and Facility GHG Emissions Reduction project are to identify potential GHG emission reduction opportunities related to Enbridge Gas's operational emissions.

g) As discussed in the application, there were four opportunities that were identified as having the potential to reduce OBPS/EPS volumes. Table 3[1] of the 2022 FCPP Application provides an overview of the identified opportunities. Additionally, as outlined in the application, Enbridge Gas is also developing a plan for compressor unit lifecycle replacement. As part of this long-term plan to replace identified compressor units, several factors are being considered in the evaluation of alternatives, including meeting the operating requirements for the storage and transmission systems, reliability, environmental compliance, and carbon reduction strategy.

h) Please see the Enbridge Gas Asset Management Plan 2021-2025, for a description of the Value Framework and how it is used in Asset Management decision making.[2]

i) Consistent with the OEB's decision in September 2021 on the Applicability of Charges to Indigenous Customers[3], the rate impacts of this Application are generic across Enbridge Gas rate classes and are applied on that basis. The annual bill impacts, including bill impacts from both customer-related and facility-related charges, that are applicable to Enbridge Gas's residential customers, including any customers in Indigenous communities, have been summarized at Exhibit A, Tab 2, Schedule 1, page 19. Detailed rate impacts are set out by rate class at Exhibit D, Tab 1 and Tab 2.

[1] EB-2021-0209, Exhibit A, Tab 2, Schedule 1, p. 14, para. 37, September 29, 2021.
[2] EB-2020-0181, EGI Asset Management Plan 2021-2025, Exhibit C, Tab 2, Schedule 1, pp. 57-60, October 15, 2020.
[3] EB-2019-0247, OEB Decision and Order, September 23, 2021.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Anwaatin Inc. (Anwaatin)

Interrogatory

Reference:

Updated Exhibit C, paras 24, 30-31.

Preamble:

EGI's forecasted 2022 administration costs are $6.99 million: $4.69 million for the EGD rate zone and $2.30 million for the Union rate zones (IT billing system, staffing resources, consulting and external legal support, greenhouse gas (GHG) reporting and verification, bad debt, and other miscellaneous costs).

EGI plans to record actual 2022 costs in the Greenhouse Gas Emissions Administration Deferral Accounts (GGEADAs) until such time that these costs are incorporated into rates. EGI intends to seek recovery of its actual 2022 administration costs in a future proceeding.

EGI states that it anticipates that it will incur a total of $0.30 million in consulting and external legal costs in 2022 for work supporting the development and sustainment of EGI's carbon strategy and related analyses, the review and interpretation of any new or updated regulations associated with the GGPPA, EPS Regulation, or other GHG or carbon pricing programs and the development of Enbridge Gas's Application and associated OEB proceedings. EGI also notes that it may incur additional consulting and external legal costs associated with other GHG or carbon policies.

Questions:

a) Please outline what additional consulting and external legal services EGI anticipates that it will require in relation to each of the following:

   (i) development and sustainment of EGI's carbon strategy and related analyses;
   (ii) review and interpretation of any new or updated regulations associated with the GGPPA;
   (iii) review and interpretation of the EPS Regulation;
   (iv) Indigenous engagement and consultation for the development and sustainment of EGI's carbon strategy and related analysis; and
   (v) other GHG or carbon policies.

Response:

a) As described in Enbridge Gas's Application at Exhibit C, page 9, Enbridge Gas is providing forecast 2022 administration costs (set out at Exhibit C, Table 3) for informational purposes only and will seek recovery of its actual 2022 administration costs in a future proceeding.

   These estimates are generally based on: (i) Enbridge Gas's 2019 – 2021 forecast and actual administration costs; and (ii) anticipated consulting and external legal services required to develop compliance strategies for and to maintain compliance with the *Greenhouse Gas Pollution Pricing Act* and the Federal Carbon Pricing Program (e.g. offset regulations), Ontario's Emissions Performance Standard ("EPS"), any other related GHG or climate policies, and any other carbon pricing programs in 2022.

   Enbridge Gas has provided these estimated costs at the level of detail currently available at the time of filing its Application and this submission. At such time that Enbridge Gas seeks, through a future application to the OEB, to recover its actual 2022 administration costs it will provide a specific breakdown of those costs.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, pages 13-17 - Management of Facility-Related Emissions and Costs

Question(s):

a) Please confirm the actual 2020 compliance costs, including excess emissions charges, and if any or all of those costs are passed on to customers.

b) Provide your forecast of 2021 and 2022 compliance costs.

c) Advise if an independent engineering study has been conducted into options for electrification of the Enbridge transmission system to reduce emissions.

Response:

a) Enbridge Gas's actual facility-related compliance costs for 2020 were $3,154,057, which includes $2,334,210 related to the 2020 OBPS compliance obligation and $819,847 related to the 2020 Company Use costs.

   The total 2020 facility-related compliance cost of $3,154,057 included both regulated and unregulated activities, and only the costs that are related to regulated activities are passed on to customers. Of the $3,154,057, the regulated portion of $2,914,667 is passed on to customers through the Facility Carbon Charge, included in delivery or transportation charges on customers' bills.

b) For the 2021 facility-related forecasts, please refer to, EGI's 2021 Federal Carbon Pricing Program Application (EB-2020-0212), at Exhibit B, Tab 1, Schedules 2 to 5 and at Exhibit B, Tab 2, Schedules 2 to 5.

   For the 2022 facility-related forecasts, please refer to EGI's 2022 Federal Carbon Pricing Program Application (EB-2021-0209), Exhibit B, Tab 1, Schedules 2 to 5 and at Exhibit B, Tab 2, Schedules 2 to 5.

c) Enbridge Gas has not undertaken an independent engineering study on electrification of its transmission system.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit A Tab 2 Schedule 1 page 19 Bill Impacts:

Question(s):

Please confirm the forecast range of percentage increases for commercial customers due to 2022 carbon charges (broken down between customer usage and costs related to Enbridge operations) and to the proposed 2020 FCPP-related deferral and variance account balance disposition.

Response:

The majority of commercial customers take service under one of Enbridge Gas's general service rate classes (Rate 6 in the EGD rate zone, Rate M1, Rate M2, Rate 01 and Rate 10 in the Union rate zones). However, commercial customers can be found in other rate classes depending on the customer's size and annual consumption. The bill impacts of the 2022 carbon charges for typical customers in each rate class, at various annual consumption levels, are provided at Exhibit D, Tab 1, Schedule 2 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 3 for the Union rate zones. The Facility Carbon Charge is embedded in the distribution/delivery charge. As such, the change in the distribution/delivery charge is equal to the change in the Facility Carbon Charge. The customer-related Federal Carbon Charge is shown as a separate line item on the bill impact schedules.

The bill impacts of the proposed 2020 FCPP-related deferral and variance account balance disposition for typical customers in each rate class is provided at Exhibit D, Tab 1, Schedule 5 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 6 for the Union rate zones.

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit C Administration Costs Tables 1 and 3:

Question:

Please explain the forecast increase from 2020 to 2022, in particular the Bad Debt allowance.

Response:

Please refer to Exhibit I.EP.3 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from The Building Owners and Managers Association (BOMA)

Interrogatory

Reference:

Exhibit D Sections 1.5 and 2.5 Bill Impacts:

Question:

Please provide the equivalent range of percentage increases for commercial customers.

Response:

Please see the response at Exhibit I.BOMA.2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Page 3, paragraph 7c and Exhibit A, Tab 2, Schedule 1, paragraph 47

Preamble:

“EGI requests an order or orders approving the 2020 balances for all FCPP-related deferral and variance accounts, for all Enbridge Gas rate zones, as set out in Exhibit C and for an order to dispose of those balances as part of the April 1, 2022 QRAM.”

Questions:

a) Please confirm EGI has audited the 2020 FCPP-related DA balances. Please provide a copy.

b) Has EGI 2021 unaudited results? If so, please provide the estimated range of the balances for each FCPP-related DV account and Total.

c) Will disposition of 2020 balances in April 2022 materially add to the bill impact of the expected increase in FCPP charges? Please answer for each Rate Zone.

Response:

a) The 2020 financial results of Enbridge Gas were audited by PricewaterhouseCoopers LLP, and the audit scope included a review of deferral account balances. Please find a copy of Enbridge Gas’s Audited 2020 Financial Statements in Attachment 1.

   The 2020 year-end results in the Federal Carbon Charge – Facility Variance Accounts (FCCFVAs) were based on an estimate. A true up to actual was recorded in 2021 once the third-party verified OBPS compliance obligation was available.

b) The balances in the 2021 deferral and variance accounts (DVAs) are not at issue in this proceeding as Enbridge Gas is not seeking recovery in this application for amounts related to the 2021 DVAs.

Enbridge Gas does not have final balances or resulting bill impacts for the 2021 FCPP-related DVAs at this time. Enbridge Gas will seek disposition of final 2021 balances in the FCPP-related DVAs for each of the EGD rate zone and Union rate zones as part of a future proceeding.

c) The bill impacts of the proposed 2020 FCPP-related DVA balance disposition for typical customers in each rate class is provided at Exhibit D, Tab 1, Schedule 5 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 6 for the Union rate zones.

Since the total bill impact from the disposition of 2020 balances in April 2022 range from 0.0% to 0.1% for each of the rate zones, the disposition of balances will not materially add to the bill impact from the increase in the FCPP charges for April 2022.

ENBRIDGE GAS INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2020

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS INC.

Financial Reporting
Management of Enbridge Gas Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors is responsible for all aspects related to governance of the Company. The Company does not have an Audit Committee, having received an exemption from such requirement.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and to provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company in accordance with Canadian generally accepted auditing standards and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

"signed"	**"signed"**
Cynthia L. Hansen	**Tanya M. Ferguson**
President	Vice President, Finance

February 12, 2021

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Independent auditor's report

To the Shareholders of Enbridge Gas Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Inc. (the Company) as at December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America (US GAAP).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2020 and 2019;
- the consolidated statements of comprehensive income for the years ended December 31, 2020 and 2019;
- the consolidated statements of changes in equity for the years ended December 31, 2020 and 2019;
- the consolidated statements of cash flows for the years ended December 31, 2020 and 2019;
- the consolidated statements of financial position as at December 31, 2020 and 2019; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

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Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

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As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Ontario
February 12, 2021

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Operating revenues		
Gas commodity and distribution	**3,631**	4,152
Storage, transportation and other	**884**	923
Total operating revenues *(Note 4)*	**4,515**	5,075
Operating expenses		
Gas commodity and distribution costs	**1,812**	2,334
Operating and administrative	**1,137**	1,109
Depreciation and amortization	**655**	638
Total operating expenses	**3,604**	4,081
Operating income	**911**	994
Other income	**56**	20
Interest expense, net *(Note 10)*	**(412)**	(400)
Earnings before income taxes	**555**	614
Income tax expense *(Note 15)*	**(58)**	(58)
Earnings	**497**	556

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings	**497**	556
Other comprehensive income/(loss), net of tax *(Notes 12 and 13)*		
Change in unrealized loss on cash flow hedges	**(37)**	(37)
Reclassification to earnings of loss on cash flow hedges	**15**	4
Recognition of regulatory offset	**—**	55
Actuarial loss on other postretirement benefits (OPEB) *(Note 16)*	**(10)**	(12)
Foreign currency translation adjustment	**—**	(5)
Other comprehensive (loss)/income, net of tax	**(32)**	5
Comprehensive income	**465**	561

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Common shares *(Note 11)*		
Balance at beginning of year	**3,517**	3,030
Capital contribution	**800**	800
Return of capital	**(800)**	(313)
Balance at end of year	**3,517**	3,517
Additional paid-in capital		
Balance at beginning and end of year	**7,253**	7,253
Deficit		
Balance at beginning of year	**(720)**	(339)
Earnings	**497**	556
Common share dividends declared	**(450)**	(937)
Adoption of new accounting standard	**(2)**	—
Balance at end of year	**(675)**	(720)
Accumulated other comprehensive loss *(Note 12)*		
Balance at beginning of year	**(46)**	(51)
Other comprehensive (loss)/income, net of tax	**(32)**	5
Balance at end of year	**(78)**	(46)
Total equity	**10,017**	10,004

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2020	2019
(millions of Canadian dollars)		
Operating activities		
Earnings	**497**	556
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**655**	638
Deferred income tax recovery	**(25)**	(31)
Net defined pension and OPEB costs	**(31)**	(17)
Loss on disposition	**—**	10
Other	**13**	5
Changes in operating assets and liabilities *(Note 18)*	**93**	116
Net cash provided by operating activities	**1,202**	1,277
Investing activities		
Capital expenditures	**(1,109)**	(1,073)
Additions to intangible assets	**(76)**	(36)
Proceeds from disposition	**—**	72
Net cash used in investing activities	**(1,185)**	(1,037)
Financing activities		
Net change in short-term borrowings	**223**	(127)
Short-term repayments to affiliate	**—**	(32)
Repayment of loans from affiliates	**(650)**	(300)
Term note issuances, net of issue costs	**1,192**	697
Term note repayments	**(400)**	—
Common share dividends	**(450)**	(937)
Return of capital	**(800)**	(313)
Capital contribution received	**800**	800
Net cash used in financing activities	**(85)**	(212)
Net (decrease)/increase in cash	**(68)**	28
Cash, cash equivalents and restricted cash at beginning of year	**77**	49
Cash at end of year	**9**	77
Supplementary cash flow information		
Cash paid for income taxes	**66**	12
Cash paid for interest, net of amounts capitalized	**385**	381
Property, plant and equipment non-cash accruals	**20**	34

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE GAS INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2020**	2019
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash	**9**	77
Accounts receivable and other *(Note 6)*	**1,161**	1,317
Accounts receivable from affiliates *(Note 19)*	**92**	46
Gas inventory	**659**	631
	1,921	2,071
Property, plant and equipment, net *(Note 7)*	**15,866**	15,418
Intangible assets, net *(Note 8)*	**174**	173
Deferred amounts and other assets	**2,492**	2,235
Goodwill	**4,784**	4,784
Total assets	**25,237**	24,681
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**1,121**	898
Accounts payable and other *(Note 9)*	**1,295**	1,369
Accounts payable to affiliates *(Note 19)*	**134**	113
Current portion of long-term debt *(Note 10)*	**376**	400
	2,926	2,780
Long-term debt *(Note 10)*	**8,606**	7,815
Other long-term liabilities	**2,166**	1,999
Deferred income taxes *(Note 15)*	**1,522**	1,433
Loan from affiliate *(Note 19)*	**—**	650
	15,220	14,677
Commitments and contingencies *(Note 21)*		
Equity		
Share capital *(Note 11)*		
Common shares *(522 million shares outstanding at December 31, 2020 and 2019)*	**3,517**	3,517
Additional paid-in capital	**7,253**	7,253
Deficit	**(675)**	(720)
Accumulated other comprehensive loss *(Note 12)*	**(78)**	(46)
	10,017	10,004
Total liabilities and equity	**25,237**	24,681

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

"signed"
Cynthia L. Hansen
Director

"signed"
David G. Unruh
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

The terms "we," "our," "us" and "Enbridge Gas" as used in these financial statements refer collectively to Enbridge Gas Inc. and its subsidiaries unless the context suggests otherwise. Enbridge Gas is a wholly-owned indirect subsidiary of Enbridge Inc. (Enbridge). Enbridge provides administrative and general support services to us.

Enbridge Gas is a rate-regulated natural gas distribution, storage and transmission utility, serving residential, commercial and industrial customers in Ontario. We also served areas in northern New York State through our wholly-owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), prior to its disposition on November 1, 2019.

AMALGAMATION

On January 1, 2019, Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) amalgamated and have continued from this date as Enbridge Gas, which continues to have all of the assets, rights, contracts, liabilities and obligations of each of EGD and Union Gas, including licenses and permits.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

We are permitted to use U.S. GAAP as our primary basis of accounting for purposes of meeting our continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues; estimates of revenue; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 8)*; measurement of goodwill; fair value of asset retirement obligations (AROs); fair value of financial instruments *(Note 13)*; provisions for income taxes *(Note 15)*; assumptions used to measure retirement benefits and OPEB *(Note 16)*; and commitments and contingencies *(Note 21)*. Actual results could differ from these estimates.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

REGULATION

Our utility operations within Ontario are regulated by the Ontario Energy Board (OEB), while the utility operations of St. Lawrence Gas were regulated by the New York State Public Service Commission. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

As a result of rate regulated accounting, we have recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates and amounts collected from customers in advance of costs being incurred. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment.

The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. The regulator's future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which we operate. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. We believe that the recovery of our regulatory assets as at December 31, 2020 is probable over the periods described in *Note 5. Regulatory Matters*.

With the approval of the regulator, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

REVENUE RECOGNITION
Revenue from contracts with customers are generally recognized upon the fulfillment of the performance obligations for the distribution, storage, transportation and sale of natural gas. For distribution and transportation service arrangements, where the services are simultaneously received and consumed by the customer, revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas. Revenues from storage services are recognized as the storage services are provided.

A significant portion of our operations are subject to regulation and, accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue under such circumstances is recognized in a manner that is consistent with the underlying rate-setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator, which are accounted for under Accounting Standards Codification (ASC) 980 - Regulated Operations.

PUSH-DOWN ACCOUNTING
EGD elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge, when it first adopted U.S. GAAP. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by EGD. Upon adopting push-down accounting, the historical cost of EGD's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

We have applied push-down accounting with respect to the accounts of Union Gas from February 27, 2017, the date upon which Enbridge acquired common control of EGD and Union Gas. The carrying values of certain assets and liabilities of Union Gas transferred to EGD have been adjusted to reflect Enbridge's historical cost as at February 27, 2017.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in interest rates and foreign exchange rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. There were no outstanding derivative instruments relating to fair value or net investment hedges as at December 31, 2020 and 2019.

Cash Flow Hedges

We use cash flow hedges to manage our exposure to changes in interest rates and foreign exchange rates related to our unregulated storage revenue. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a deduction from Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge Gas or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Prior to its sale in 2019, our only foreign operation was St. Lawrence Gas. The functional currency of St. Lawrence Gas was the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas to Canadian dollars were included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI) and were recognized in earnings upon its sale. Asset and liability accounts were translated at the exchange rates in effect on the balance sheet date, while revenues and expenses were translated using monthly average exchange rates.

CASH

We combine cash and bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements.

RECEIVABLES AND CURRENT EXPECTED CREDIT LOSSES

Accounts receivable are measured at cost. For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received and delivered for customers. Since certain imbalances are settled in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

GAS INVENTORY

Gas inventories primarily consist of natural gas held in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the regulators in the determination of distribution rates. The actual price of gas purchased may differ from the regulator’s approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the regulator.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest incurred during construction as authorized by the regulator. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit.

The pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the regulator. When grouped assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation until the last asset in the pool is disposed of. Gains and losses on the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the regulator, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the regulator.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; derivative financial instruments; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs. We capitalize costs incurred during the application development stage of internal use software projects. Intangible assets are generally amortized on a straight line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of goodwill and comparing that value to its carrying value. If the carrying value, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the carrying value exceeds the fair value. This amount should not exceed the carrying amount of goodwill. Fair value is estimated using a discounted cash flow model technique. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of our assets, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

PENSION AND OPEB

We provide pension benefits through defined benefit and defined contribution pension plans and OPEB, including group health care and life insurance benefits through defined benefit OPEB plans.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligation of our pension plans.

We determine discount rates by reference to rates of high quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

Funded pension plan assets are measured at fair value. The expected return on funded pension plan assets is determined using market-related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market-related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period (funded pension plans) and from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount and salary inflation experience.

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in the Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (funded pension plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit OPEB plans are presented as a component of AOCI in the Consolidated Statements of Changes in Equity. Any unrecognized OPEB-related actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans, which have been permitted or are expected to be permitted by the regulator, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in the Consolidated Statements of Financial Position.

We also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to earnings and OCI on an accrual basis.

For defined contribution plans, contributions made by us are expensed in the period in which the contribution occurs.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount or, if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW ACCOUNTING STANDARDS

Reference Rate Reform

Effective July 1, 2020, we adopted Accounting Standards Update (ASU) 2020-04 on a prospective basis. The new standard was issued in March 2020 to provide temporary optional guidance in accounting for reference rate reform. The new guidance provides optional expedients and exceptions for applying generally accepted accounting principles when accounting for contract modifications, hedging relationships and other transactions impacted by rate reform, subject to meeting certain criteria. ASU 2020-04 is effective until December 31, 2022. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Disclosure Effectiveness

Effective January 1, 2020, we adopted ASU 2018-13 on both a retrospective and prospective basis depending on the change. The new standard was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Credit Losses

Effective January 1, 2020, we adopted ASU 2016-13 on a modified retrospective basis.

The new standard was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The previous accounting treatment used the incurred loss methodology for recognizing credit losses that delayed the recognition until it was probable a loss had been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes results in more timely recognition of such losses.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses.

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations.

The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for Income Taxes

ASU 2019-12 was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740, as well as provides simplification by clarifying and amending existing guidance. ASU 2019-12 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2019-12 is not expected to have a material impact on our consolidated financial statements.

Disclosure Effectiveness
ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. The adoption of ASU 2018-14 is not expected to have a material impact on our consolidated financial statements.

4. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Services

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Gas commodity and distribution revenues - residential	**2,560**	2,847
Gas commodity and distribution revenues - commercial and industrial	**1,077**	1,316
Storage revenue	**144**	140
Transportation revenue	**681**	716
Other revenues	**62**	65
Total revenue from contracts with customers	**4,524**	5,084
Other[1]	**(9)**	(9)
Total revenues	**4,515**	5,075

1 Primarily relates to the effects of rate-regulated accounting.

We disaggregate revenues into categories which represent our principal performance obligations. These revenue categories also represent the most significant revenue streams, and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Liabilities
(millions of Canadian dollars)		
Balance as at December 31, 2020	**738**	**—**
Balance as at December 31, 2019	613	65

Receivables represent an unconditional right to consideration where only the passage of time is required before payment of consideration is due, and consist of trade accounts receivable, unbilled revenue and other accrued receivable balances.

Contract liabilities represent payments received for performance obligations which have not been fulfilled under our equal monthly payment plan. Revenue recognized during the year ended December 31, 2020 included $65 million of contract liabilities which had not been fulfilled as at the beginning of the year. The increase in contract liabilities from cash received, net of amounts recognized as revenues during the year ended December 31, 2020, was nil.

Performance Obligations

	Nature of Performance Obligation
Gas commodity and distribution revenue	• Supply and delivery of natural gas to customers
Storage and transportation revenue	• Storage and transportation of natural gas on behalf of customers
Other revenue	• Other billing and service fees

We recognized a reduction of revenue of $22 million during the year ended December 31, 2020 from performance obligations satisfied in previous periods, primarily resulting from differences in actual and estimated consumption. The associated reduction in gas commodity and distribution costs was also recognized in the current year.

Payment Terms

Payments from distribution customers are received on a continuous basis based on established billing cycles. Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. Payments from storage customers are received monthly under long-term storage capacity contracts. Payments from transportation customers are received on a continuous basis based on established billing cycles or monthly under long-term transportation capacity contracts.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $581 million, of which $310 million is expected to be recognized during the year ending December 31, 2021.

The performance obligations above reflect revenues expected to be recognized in future periods from unfulfilled performance obligations pursuant to contracts with customers for the purchase of natural gas distribution, storage and transportation services. Certain revenues are excluded from the amounts above under the following ASC 606 optional exemptions:

- certain revenues, such as flow-through costs charged to customers, which are recognized at the amount for which we have the right to invoice our customers; and
- revenue from contracts with customers that have an original expected duration of one year or less.

Variable consideration is also excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be reasonably estimated.

A significant portion of our operations are subject to regulation. Accordingly, the amounts above, in addition to revenues that are not regulated, only include revenue for which the underlying rate has been approved by regulation, where applicable. The revenues excluded from the amounts above could represent a significant portion of our overall revenues and revenue from contracts with customers.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Revenue Recognition

Revenue from contracts with customers is generally recognized upon the fulfillment of the performance obligations as described above. Distribution and transportation service revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Due to regulatory mechanisms, there are circumstances where revenues recognized do not match the amounts billed. Under such circumstances, revenue is recognized in a manner that is consistent with the underlying rate setting mechanism as approved by the regulator. This may give rise to regulatory deferral accounts pending disposition by decisions of the regulator.

Recognition and Measurement of Revenues

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Revenue from products and services transferred over time[1]	**4,464**	5,019
Revenue from products transferred at a point in time[2]	**60**	65
Total revenue from contracts with customers	**4,524**	5,084

1 Revenue from distribution, storage and transportation services.
2 Primarily from Other revenues.

Performance Obligations Satisfied Over Time

For arrangements involving the distribution and transportation of natural gas, where the services are simultaneously received and consumed by the customer, we recognize revenue over time using an output method based on volumes of commodities delivered. The measurement of the volumes delivered corresponds directly to the benefits received by the customers during that period. Revenue from storage services are recognized as the services are provided.

Determination of Transaction Prices

Prices for distribution and transportation services and regulated storage services are prescribed by regulation. Fees for unregulated storage services are determined through negotiations with customers and are based on market rates.

Prices for natural gas sold are driven by market prices and the Quarterly Rate Adjustment Mechanism (QRAM) in place that allows for rates to reflect changes in natural gas prices, subject to regulatory approval.

5. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under U.S. GAAP for non-regulated entities. See *Note 2* for further discussion.

We are regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act*, (1998), which is part of a package of legislation known as the *Energy Competition Act*, (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario.

RATE APPROVALS

Our distribution rates, commencing in 2019, are set under a five-year Incentive Regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% stretch factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires us to share equally with customers any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following regulatory assets and liabilities in the Consolidated Statements of Financial Position:

December 31,	**2020**	2019	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Federal carbon receivables[1]	**—**	145	2020
Demand side management program	**31**	28	2021
Purchase gas variance[2]	**—**	23	2021
Other current regulatory assets	**86**	94	2021
Total current regulatory assets[3] *(Note 6)*	**117**	290	
Long-term regulatory assets			
Deferred income taxes[4]	**1,393**	1,266	Various
Pension plan receivable[5]	**342**	222	Various
Long-term debt[6]	**334**	362	2022-2046
Accounting policy changes[7]	**169**	175	Various
Transition impact of accounting changes[8]	**53**	53	2032
Other long-term regulatory assets	**34**	12	Various
Total long-term regulatory assets[3]	**2,325**	2,090	
Total regulatory assets	**2,442**	2,380	
Current regulatory liabilities			
Purchase gas variance[2]	**153**	41	2021
Other current regulatory liabilities	**73**	176	2021
Total current regulatory liabilities[9] *(Note 9)*	**226**	217	
Long-term regulatory liabilities			
Future removal and site restoration reserves[10]	**1,455**	1,424	Various
Accelerated capital cost allowance	**43**	28	Various
Other long-term regulatory liabilities	**45**	19	Various
Total long-term regulatory liabilities[9]	**1,543**	1,471	
Total regulatory liabilities	**1,769**	1,688	

1 *The federal carbon balance is the difference between actual carbon costs and carbon costs recovered in rates, as well as the administration costs associated with the impacts of the federal carbon program requirements. This balance has been recovered from customers in the fourth quarter of 2020 in accordance with the OEB's approval.*

2 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. We have been granted OEB approval to refund this balance to, or collect this balance from, customers on a rolling 12 month basis as part of the QRAM process.*

3 *Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.*

4 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.*

5 *The pension plan balance represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.*

6 *The debt balance represents our regulatory offset to the fair value adjustment to debt acquired in Enbridge's merger with Spectra Energy Corp. (Spectra Energy) and pushed down to Enbridge Gas. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

7 *The accounting policy changes deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas, relating to the period up to Enbridge's merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income and recovered in rates, as previously approved by the OEB.*

8 *The transition impact of accounting changes balance represents our right to recover costs resulting from the adoption of the accrual basis of accounting for pension and OPEB costs upon transition to U.S. GAAP in 2012. Pursuant to the OEB rate order, the balance as at December 31, 2012 is to be collected in rates over a 20 year period, commencing in 2013.*

9 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

10 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

With the approval of the OEB, we capitalize a percentage of certain operating costs. We are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate-regulated accounting, a portion of such operating costs would be charged to earnings in the year incurred.

We entered into a services contract relating to asset management initiatives. The majority of these costs were capitalized to Gas mains in accordance with regulatory approval. As at December 31, 2020, the net book value of the costs included in Gas mains, services and other in Property, plant and equipment, net was $96 million (2019 - $103 million).

Work and Asset Management Solution (WAMS) is our integrated work and asset management system. As at December 31, 2020, the net book value of the WAMS asset included in Intangible assets, net was $51 million (2019 - $60 million).

Gas Inventories

Natural gas in storage is recorded in inventory at the reference prices approved by the OEB in the determination of customers' system supply rates. Included in Gas inventory as at December 31, 2020 is $60 million (2019 - $66 million) related to storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during our off-peak months and charged to gas costs during the peak winter months. In the absence of rate-regulated accounting, these costs would be expensed as incurred, and inventory would be recorded at the lower of cost or market value.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2020**	2019
(millions of Canadian dollars)		
Trade receivables and unbilled revenues, net[1]	**855**	857
Regulatory assets *(Note 5)*	**117**	290
Rebillables receivable	**76**	88
Gas imbalances	**54**	44
Other	**59**	38
	1,161	1,317

1 Net of allowance for expected credit losses of $45 million as at December 31, 2020 and allowance for doubtful accounts of $38 million as at December 31, 2019.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2020**	2019
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas transmission	**2.5%**	**1,752**	1,505
Gas mains, services and other	**2.6%**	**12,476**	12,114
Compressors, meters and other operating equipment	**4.3%**	**3,235**	2,918
Storage	**2.8%**	**975**	919
Land and right-of-way[1]	**1.0%**	**361**	334
Vehicles, office furniture, equipment and other buildings and improvements	**10.7%**	**434**	506
Under construction	**—%**	**177**	223
		19,410	18,519
Accumulated depreciation		**(3,946)**	(3,490)
		15,464	15,029
Unregulated property, plant and equipment			
Gas mains, services and other	**5.6%**	**13**	13
Compressors, meters and other operating equipment	**1.3%**	**41**	40
Storage	**3.0%**	**365**	347
Land and right-of-way[1]	**1.7%**	**37**	32
Under construction	**—%**	**30**	24
		486	456
Accumulated depreciation		**(84)**	(67)
		402	389
Property, plant and equipment, net		**15,866**	15,418

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense, including amounts collected for future removal and site restoration costs, was $583 million for the year ended December 31, 2020 (2019 - $558 million).

Included within depreciation expense is $22 million for the year ended December 31, 2020 (2019 - $22 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

DISPOSITION

On November 1, 2019, we closed the sale of St. Lawrence Gas for total cash proceeds of approximately $72 million (US$55 million). A loss on disposal of approximately $10 million before tax was included in Other income in the Consolidated Statements of Earnings in 2019.

8. INTANGIBLE ASSETS

December 31,	**2020**	2019
(millions of Canadian dollars)		
Software and Customer Information System	**654**	592
Less: Accumulated amortization	**(480)**	(419)
Intangible assets, net	**174**	173

For the year ended December 31, 2020, the weighted average amortization rate for software and CIS was 11.8% (2019 - 13.9%).

Intangible assets include $35 million of work-in-progress as at December 31, 2020 (2019 - $16 million). Total amortization expense for intangible assets was $72 million for the year ended December 31, 2020 (2019 - $80 million). The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2021	2022	2023	2024	2025
(millions of Canadian dollars)					
Forecast of amortization expense	64	18	16	16	16

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2020**	2019
(millions of Canadian dollars)		
Trade payables and accrued liabilities	**491**	464
Regulatory liabilities *(Note 5)*	**226**	217
Federal carbon program liability	**194**	140
Construction payables and contractor holdbacks	**73**	112
Gas imbalances	**54**	44
Taxes payable	**47**	114
Other	**210**	278
	1,295	1,369

10. DEBT

December 31,	Weighted Average Interest Rate[3]	Maturity	**2020**	2019
(millions of Canadian dollars)				
Medium-term notes	3.9 %	2021-2050	**8,485**	7,685
Debentures	9.1 %	2024-2025	**210**	210
Commercial paper and credit facility draws	0.3 %	2022	**1,121**	898
Other[1]			**(47)**	(42)
Fair value adjustment from push down accounting *(Note 2)*			**334**	362
Total debt			**10,103**	9,113
Current maturities			**(376)**	(400)
Short-term borrowings[2]			**(1,121)**	(898)
Long-term debt			**8,606**	7,815

1 Primarily unamortized discounts, premiums and debt issuance costs.
2 Weighted average interest rate - 0.3% (2019 - 2.0%).
3 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2020.

As at December 31, 2020, all outstanding debt was unsecured.

CREDIT FACILITIES

We actively manage our bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of our external credit facility at December 31, 2020:

	Maturity	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
364 day extendible credit facility	2022[1]	**2,000**	**1,121**	**879**

1 Maturity date is inclusive of the one-year term out provision.
2 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

On July 24, 2020, we extended our 364 extendible credit facility to July 23, 2022, inclusive of a one-year term out provision.

The credit facility carries a standby fee of 0.3% on the unused portion and the draws bear interest at market rates.

As at December 31, 2020, we have access to Enbridge's demand letter of credit facilities totaling $495 million (2019 - $495 million). As at December 31, 2020 and 2019, $14 million of letters of credit were issued by us.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2020, we completed the following long-term debt issuances totaling $1.2 billion:

Issue Date		Principal Amount
(millions of Canadian dollars)		
April 2020	2.90% medium-term notes due April 2030	$600
April 2020	3.65% medium-term notes due April 2050	$600

With proceeds from these issuances, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast Energy Inc. on April 1, 2020. The note was presented as Loan from affiliate in the Consolidated Statements of Financial Position as at December 31, 2019.

LONG-TERM DEBT REPAYMENT

During the year ended December 31, 2020, we completed the following long-term debt repayment totaling $400 million:

Repayment Date		Principal Amount
(millions of Canadian dollars)		
November 2020	4.04% medium-term notes	$400

DEBT COVENANTS

Our credit facility agreement and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or terminations of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2020, we are in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Debentures and term notes	**380**	331
Commercial paper and credit facility draws	**17**	31
Interest on loans from affiliate	**6**	31
Other interest and finance costs	**14**	12
Capitalized interest	**(5)**	(5)
	412	400

11. SHARE CAPITAL

As at December 31, 2020, our authorized share capital consisted of an unlimited number of common shares with no par value and an unlimited number of preference shares. Our Class A and Class B common shares are held by Enbridge Energy Distribution Inc. (EEDI) and Great Lakes Basin Energy LP (GLBE), respectively. Both classes of common shares are identical in every respect, and dividends cannot be paid to one class without paying dividends to the other. As at December 31, 2020 and 2019, no preferred shares were issued and outstanding.

COMMON SHARES

	2020		2019	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Class A				
Balance at beginning of year	**282**	**2,636**	233	2,373
Common shares converted from amalgamation[1]	**—**	**—**	(233)	(2,373)
Common shares issued from amalgamation[1]	**—**	**—**	282	2,373
Capital contribution	**—**	**432**	—	432
Return of capital	**—**	**(432)**	—	(169)
	282	**2,636**	282	2,636
Class B				
Balance at beginning of year	**240**	**881**	58	657
Common shares converted from amalgamation[2]	**—**	**—**	(58)	(657)
Common shares issued from amalgamation[2]	**—**	**—**	240	657
Capital contribution	**—**	**368**	—	368
Return of capital	**—**	**(368)**	—	(144)
	240	**881**	240	881
Balance at end of year	**522**	**3,517**	522	3,517

1 On January 1, 2019, we issued to EEDI, which wholly-owned EGD and owned 1% of Union Gas, 281,881,334 Class A common shares in exchange for 232,749,988 EGD common shares and 621,866 Union Gas Class A common shares.
2 On January 1, 2019, we issued to GLBE, which owned 99% of Union Gas, 240,020,243 Class B common shares in exchange for 57,822,650 Union Gas common shares.

The capital contribution and return of capital transactions to the stated capital of Class A and Class B common shares had no impact on the total shares outstanding.

12. COMPONENTS OF AOCI

Changes in AOCI for the years ended December 31, 2020 and 2019 are as follows:

	2020			
	Cash Flow Hedges	Cumulative Translation Adjustment	OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2020	**(42)**	**—**	**(4)**	**(46)**
Other comprehensive loss retained in AOCI	**(49)**	**—**	**(13)**	**(62)**
Other comprehensive loss reclassified to earnings	**17**	**—**	**—**	**17**
	(74)	**—**	**(17)**	**(91)**
Tax impact				
Income tax on amounts retained in AOCI	**12**	**—**	**3**	**15**
Income tax on amounts reclassified to earnings	**(2)**	**—**	**—**	**(2)**
	10	**—**	**3**	**13**
Balance at December 31, 2020	**(64)**	**—**	**(14)**	**(78)**

	2019			
	Cash Flow Hedges	Cumulative Translation Adjustment	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2019	(9)	5	(47)	(51)
Other comprehensive (loss)/income retained in AOCI[1]	(50)	(2)	58	6
Other comprehensive loss/(income) reclassified to earnings	5	(3)	—	2
	(54)	—	11	(43)
Tax impact				
Income tax on amounts retained in AOCI[1]	13	—	(15)	(2)
Income tax on amounts reclassified to earnings	(1)	—	—	(1)
	12	—	(15)	(3)
Balance at December 31, 2019	(42)	—	(4)	(46)

1 *OCI for the year ended December 31, 2019 was increased by an adjustment of $74 million in respect of Enbridge Gas applying rate-regulated accounting to record a regulatory offset to certain pension liabilities. An offsetting amount of $19 million was also recorded in OCI for the related tax impact.*

13. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in natural gas prices, foreign exchange rates and interest rates (collectively, market risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by our customers.

Foreign Exchange Risk
Foreign exchange risk is the risk of gain or loss due to the volatility of currency exchange rates. We generate certain revenues, incur expenses and hold cash balances that are denominated in USD. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from USD exchange rate variability.

We have implemented a policy to hedge a portion of our USD denominated unregulated storage revenue exposures. Qualifying derivative instruments are used to hedge anticipated USD denominated revenues and to manage variability in cash flows.

A portion of our natural gas purchases are denominated in USD and, as a result, there is exposure to fluctuations in the exchange rate of the USD against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to customers, therefore, we have no net exposure to movements in the foreign exchange rate on natural gas purchases.

Until November 1, 2019, we held a subsidiary that generated revenues denominated in USD.

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating-to-fixed interest rate swaps with an average swap rate of 2.3%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 1.9%.

COVID-19 PANDEMIC RISK
The COVID-19 pandemic has caused significant volatility in Canada, the United States and international markets. While we have taken proactive measures to deliver energy safely and reliably during this pandemic, given the ongoing dynamic nature of the circumstances surrounding COVID-19, the impact of this pandemic on our business remains uncertain.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

We generally have a common practice of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	**8**	**—**	**8**	**(1)**	**7**
	8	**—**	**8**	**(1)**	**7**
Accounts payable to affiliates					
Interest rate contracts	**(43)**	**—**	**(43)**	**—**	**(43)**
	(43)	**—**	**(43)**	**—**	**(43)**
Other long-term liabilities					
Interest rate contracts	**(1)**	**—**	**(1)**	**1**	**—**
	(1)	**—**	**(1)**	**1**	**—**
Total net derivative liability					
Interest rate contracts	**(36)**	**—**	**(36)**	**—**	**(36)**
	(36)	**—**	**(36)**	**—**	**(36)**

December 31, 2019	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable to affiliates					
Interest rate contracts	(9)	—	(9)	—	(9)
	(9)	—	(9)	—	(9)
Other long-term liabilities					
Interest rate contracts	(13)	—	(13)	—	(13)
	(13)	—	(13)	—	(13)
Total net derivative liability					
Interest rate contracts	(22)	—	(22)	—	(22)
	(22)	—	(22)	—	(22)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

December 31, 2020	2021	2022	2023	2024	2025	Thereafter	Total
Foreign exchange contracts - United States dollar forwards - sell *(millions of USD)*	**2**	**1**	**—**	**—**	**—**	**—**	**3**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**387**	**18**	**—**	**—**	**—**	**—**	**405**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**275**	**200**	**200**	**—**	**—**	**—**	**675**

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on our consolidated earnings and comprehensive income, before the effect of income taxes.

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Amount of unrealized loss recognized in OCI		
Cash flow hedges		
Interest rate contracts	**(49)**	(50)
	(49)	(50)
Amount of loss/(gain) reclassified from AOCI to earnings		
Interest rate contracts[1]	**17**	6
Foreign exchange contracts	**—**	(1)
	17	5

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

We estimate that a loss of $10 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 13 months as at December 31, 2020.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments, as they become due. In order to manage this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under the committed credit facility and long-term debt, which includes debentures and medium-term notes and, if necessary, additional liquidity is available through intercompany transactions with our ultimate parent, Enbridge, and other related entities. These sources are expected to be sufficient to enable us to fund all anticipated requirements. We maintain a current medium-term note shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. We also maintain a committed credit facility with a diversified group of banks and institutions. We were in compliance with all of the terms and conditions of our committed credit facility as at December 31, 2020. As a result, the credit facility is available to us and the banks are obligated to fund us under the terms of the facility.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. We are exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by our large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default of receivables. Generally, we classify receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

In July 2020, we began administering the Government of Ontario-funded COVID-19 Energy Assistance Program (CEAP) to eligible residential natural gas customers who have experienced hardships as a result of the COVID-19 pandemic. In August 2020, the CEAP was expanded to include small business and registered charity customers. Additional government assistance programs may also be administered by us in the future.

Our policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which generally require payment in full within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made accordingly.

Our expected credit loss is determined based on historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations, using a loss allowance matrix. This estimate is revised each reporting period to reflect current expectations. When we have determined that collection efforts are unlikely to be successful, amounts charged to the expected credit loss account are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits our exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

Entering into derivative financial instruments may also result in exposure to credit risk. We enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. As at December 31, 2020, we have $8 million credit concentrations and credit exposure with Enbridge and its affiliates.

Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair values of financial instruments reflect our best estimates of fair value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. We do not have any derivative instruments classified as Level 1.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support a Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. We do not have any derivative instruments classified as Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value, including discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, we use observable market prices (interest, foreign exchange and natural gas) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

At December 31, 2020, we had Level 2 derivative assets with a fair value of $8 million, (2019 - nil) and Level 2 derivative liabilities with a fair value of $44 million (2019 - $22 million).

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS
The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2020, our long-term debt, including the current portion, had a carrying value of $8.7 billion (2019 - $7.9 billion) before debt issuance costs and fair value adjustment from push down accounting, and a fair value of $10.7 billion (2019 - $9.2 billion).

The fair value of financial assets and liabilities, other than derivative instruments and long-term debt, approximate their carrying value due to the short period to maturity.

14. LEASES

LESSEE
We incur operating lease payments related to natural gas transportation, storage and real estate assets. These lease agreements have remaining lease terms of 3 months to 17 years, some of which include options to terminate at our discretion.

For the years ended December 31, 2020 and 2019, we incurred operating lease expenses of $9 million and $7 million, respectively. Operating lease expenses are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2020 and 2019, operating lease payments made to settle lease liabilities were $9 million and $7 million, respectively. Operating lease payments are reported within Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Consolidated Statements of Financial Position Information

December 31,	**2020**	2019
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**53**	46
Operating lease liabilities - current[2]	**6**	6
Operating lease liabilities - long-term[3]	**47**	40
Total operating lease liabilities	**53**	46
Weighted average remaining lease term		
Operating leases	**9 years**	9 years
Weighted average discount rate		
Operating leases	**3.1%**	3.3%

1 Right-of-use assets are reported within Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported within Accounts payable and other and Accounts payable to affiliates in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported within Other long-term liabilities in the Consolidated Statements of Financial Position.

As at December 31, 2020, we have lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2021	**8**
2022	**7**
2023	**7**
2024	**6**
2025	**6**
Thereafter	**27**
Total undiscounted lease payments	**61**
Less imputed interest	**(8)**
Total operating lease liabilities	**53**

LESSOR

We receive revenues from operating and sales-type leases primarily related to natural gas equipment and real estate assets. Our lease agreements have remaining lease terms of 1 month to 20 years for the year ended December 31, 2020.

As at December 31, 2020, the following table sets out future lease payments to be received under operating lease and sales-type lease contracts where we are the lessor:

	Operating leases	Sales-type leases
(millions of Canadian dollars)		
2021	**2**	**1**
2022	**1**	**1**
2023	**1**	**1**
2024	**1**	**1**
2025	**1**	**1**
Thereafter	**3**	**18**
Future lease payments to be received	**9**	**23**

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings before income taxes	**555**	614
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**83**	92
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(13)**	29
Effects of rate-regulated accounting[1]	**(46)**	(52)
Part VI.1 tax, net of federal Part I deduction[1]	**41**	—
Non-taxable portion of loss on sale of investment to unrelated party	**—**	(1)
Other[2]	**(7)**	(10)
Income tax expense	**58**	58
Effective income tax rate	**10.5%**	9.4%

1 The provincial tax component of these items is included in Provincial and state income taxes above.
2 Includes miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals and entertainment and a change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Earnings before income taxes		
Canada	**555**	638
United States	**—**	(24)
	555	614
Current income taxes		
Canada	**84**	85
United States	**(1)**	4
	83	89
Deferred income taxes		
Canada	**(25)**	(25)
United States	**—**	(6)
	(25)	(31)
Income tax expense	**58**	58

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,586)**	(1,497)
Regulatory assets	**(368)**	(335)
Deferrals	**(10)**	(17)
Pension and OPEB plans	**(13)**	(8)
Other	**(2)**	(1)
Total deferred income tax liabilities	**(1,979)**	(1,858)
Deferred income tax assets		
Future removal and site restoration reserves	**391**	373
Minimum tax credits	**40**	30
Financial instruments	**24**	15
Other	**2**	7
Total deferred income tax assets	**457**	425
Net deferred income tax liabilities	**(1,522)**	(1,433)

Enbridge Gas is subject to taxation in Canada. Prior to its disposition on November 1, 2019, we were also subject to taxation in the United States through our wholly-owned subsidiary St. Lawrence Gas. The material jurisdiction in which we are subject to potential examinations is Canada (Federal and Ontario). We are open to examination by Canadian tax authorities for 2012 to 2020 tax years, and are currently under examination for income tax matters in Canada for 2015 to 2017 tax years.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**39**	39
Gross increases for tax positions of current year	**—**	3
Gross decreases for tax positions of prior year	**(2)**	(1)
Lapses of statute of limitations	**(3)**	(2)
Unrecognized tax benefits at end of year	**34**	39

The unrecognized tax benefits as at December 31, 2020, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2020 and 2019 included no amounts of interest and penalties. As at December 31, 2020 and 2019, interest and penalties of $1 million have been accrued.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We provide pension benefits, covering substantially all employees, through contributory and non-contributory registered defined benefit and defined contribution pension plans. We also provide non-registered pension benefits for certain employees through supplemental non-contributory defined benefit pension plans.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant's years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant's retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant's current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant's current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

OTHER POSTRETIREMENT BENEFIT PLANS

We provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees, through unfunded defined benefit OPEB plans.

BENEFIT OBLIGATIONS, PLAN ASSETS AND FUNDED STATUS

The following table details the changes in the benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit pension and OPEB plans:

	Pension		OPEB	
December 31,	**2020**	2019	**2020**	2019
(millions of Canadian dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	**2,331**	2,080	**170**	153
Service cost	**68**	63	**3**	2
Interest cost	**66**	72	**5**	5
Participant contributions	**15**	14	**—**	—
Actuarial loss[1]	**160**	210	**13**	15
Benefits paid	**(108)**	(108)	**(5)**	(5)
Benefit obligation at end of year[2]	**2,532**	2,331	**186**	170
Change in plan assets				
Fair value of plan assets at beginning of year	**2,108**	1,923	**—**	—
Actual return on plan assets	**152**	237	**—**	—
Employer contributions	**52**	42	**5**	5
Participant contributions	**15**	14	**—**	—
Benefits paid	**(108)**	(108)	**(5)**	(5)
Fair value of plan assets at end of year	**2,219**	2,108	**—**	—
Underfunded status at end of year	**(313)**	(223)	**(186)**	(170)
Presented as follows:				
Deferred amounts and other assets	**35**	34	**—**	—
Accounts payable and other	**(3)**	(2)	**(7)**	(7)
Other long-term liabilities	**(345)**	(255)	**(179)**	(163)
	(313)	(223)	**(186)**	(170)

1 Primarily due to decrease in the discount rate used to measure the benefit obligations.

2 For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for our pension plans was $2.4 billion and $2.2 billion as at December 31, 2020 and 2019, respectively.

Certain of our pension plans have projected and accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Projected benefit obligation	**2,115**	784
Accumulated benefit obligation	**1,963**	686
Fair value of plan assets	**1,767**	593

AMOUNT RECOGNIZED IN AOCI

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Net actuarial loss	**18**	5
Total amount recognized in AOCI	**18**	5

NET PERIODIC BENEFIT COST AND OTHER AMOUNTS RECOGNIZED IN COMPREHENSIVE INCOME

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2020**	2019	**2020**	2019
(millions of Canadian dollars)				
Service cost	**68**	63	**3**	2
Interest cost[1]	**66**	72	**5**	5
Expected return on plan assets[1]	**(136)**	(129)	**—**	—
Amortization of net actuarial loss[1,2]	**20**	16	**—**	—
Net periodic benefit cost	**18**	22	**8**	7
Defined contribution benefit cost	**2**	2	**—**	—
Net pension and OPEB cost recognized in Earnings	**20**	24	**8**	7
Amount recognized in OCI:				
Adjustment for rate-regulated accounting *(Note 12)*	**—**	(74)	**—**	—
Net actuarial loss arising during the year	**—**	—	**13**	16
Total amount recognized in OCI	**—**	(74)	**13**	16
Total amount recognized in Comprehensive income	**20**	(50)	**21**	23

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
2 Reflects amortization of net actuarial loss arising from pension plans that are recognized as long-term regulatory assets (Note 5).

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligation and net periodic benefit cost of our defined benefit pension and OPEB plans are as follows:

	Pension		OPEB	
	2020	2019	**2020**	2019
Benefit obligations				
Discount rate	**2.6%**	3.1%	**2.6%**	3.1%
Rate of salary increase	**2.6%**	3.2%	**2.4%**	3.3%
Net benefit cost				
Discount rate	**3.1%**	3.8%	**3.1%**	3.8%
Rate of return on plan assets	**6.5%**	6.8%	**N/A**	N/A
Rate of salary increase	**3.2%**	3.2%	**3.3%**	3.3%

ASSUMED HEALTH CARE COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	2020	2019
Health care cost trend rate assumed for next year	**4.0%**	4.0%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.0%

PLAN ASSETS

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	**Target Allocation**	December 31, **2020**	December 31, 2019
Equity securities	**40.8%**	**46.3%**	45.7%
Fixed income securities	**35.5%**	**31.9%**	33.7%
Alternatives[1]	**23.7%**	**21.8%**	20.6%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	2020				2019			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Cash and cash equivalents	**50**	**—**	**—**	**50**	53	—	—	53
Equity securities								
Canada	**103**	**111**	**—**	**214**	92	112	—	204
Global	**—**	**813**	**—**	**813**	—	760	—	760
Fixed income securities								
Government	**125**	**249**	**—**	**374**	117	272	—	389
Corporate	**—**	**284**	**—**	**284**	—	268	—	268
Alternatives[4]	**—**	**—**	**466**	**466**	—	—	427	427
Forward currency contracts	**—**	**18**	**—**	**18**	—	7	—	7
Total pension plan assets at fair value	**278**	**1,475**	**466**	**2,219**	262	1,419	427	2,108

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Balance at beginning of year	**427**	298
Unrealized and realized gains	**(3)**	9
Purchases and settlements, net	**42**	120
Balance at end of year	**466**	427

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2021	2022	2023	2024	2025	2026-2030
(millions of Canadian dollars)						
Pension	108	109	111	113	115	599
OPEB	7	7	8	8	8	41

EXPECTED EMPLOYER CONTRIBUTIONS

In 2021, we expect to contribute approximately $39 million and $7 million to the pension plans and OPEB plans, respectively.

17. SEVERANCE COSTS

For the year ended December 31, 2020, we incurred $74 million in severance costs related to Enbridge's voluntary workforce reduction program. For the year ended December 31, 2019, we incurred $39 million in severance costs related to the amalgamation of EGD and Union Gas. Severance costs are presented in Operating and administrative expense in the Consolidated Statements of Earnings.

18. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2020**	2019
(millions of Canadian dollars)		
Accounts receivable and other	**65**	(17)
Accounts receivable from affiliates	**(46)**	(24)
Regulatory assets	**156**	29
Gas inventory	**(39)**	48
Deferred amounts and other assets	**10**	(2)
Accounts payable and other	**(55)**	(45)
Accounts payable to affiliates	**(40)**	18
Regulatory liabilities	**54**	105
Other long-term liabilities	**(12)**	(8)
Assets held for sale	**—**	12
	93	116

19. RELATED PARTY TRANSACTIONS

All related party transactions are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Affiliates refer to Enbridge and companies that are either directly or indirectly owned by Enbridge.

Enbridge and its affiliates perform centralized corporate functions for us pursuant to applicable agreements, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. We reimburse Enbridge for the expenses incurred to provide these services, as well as for other expenses incurred on our behalf. In addition, we perform services and incur expenses on behalf of our affiliates, which are subsequently reimbursed. Our expenses and recoveries for these services are recorded in Operating and administrative expense in the Consolidated Statements of Earnings, and are based on the cost of actual services provided or using various allocation methodologies.

Our transactions with entities related through common or joint control and significantly influenced investees are as follows:

Year ended December 31, 2020	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	**—**	**—**	**131**	**6**	**14**
Westcoast Energy Inc.	**—**	**—**	**—**	**—**	**(6)**
Tidal Energy Marketing Inc.	**11**	**13**	**—**	**—**	**—**
Tidal Energy Marketing (U.S.) LLC	**—**	**18**	**—**	**—**	**—**
Gazifère Inc.	**26**	**—**	**—**	**—**	**—**
Énergir, L.P.	**37**	**—**	**—**	**—**	**—**
Vector Pipeline, LLC (U.S.)	**—**	**19**	**—**	**—**	**—**
NEXUS Gas Transmission, LLC	**—**	**116**	**—**	**—**	**—**
Other affiliates, net	**2**	**3**	**7**	**—**	**—**

Year ended December 31, 2019	Operating revenues	Gas commodity and distribution costs	Operating and administrative expense	Other Income	Interest income/ (expense)
(millions of Canadian dollars)					
Enbridge Inc.	—	—	99	—	7
Westcoast Energy Inc.	—	—	—	—	(24)
Tidal Energy Marketing Inc.	11	38	—	—	—
Tidal Energy Marketing (U.S.) LLC	—	37	—	—	—
Gazifère Inc.	30	—	—	—	—
Énergir, L.P.	10	—	—	—	—
Vector Pipeline, LLC (U.S.)	—	19	—	—	—
NEXUS Gas Transmission, LLC	—	114	—	—	—
Other affiliates, net	2	8	6	—	(1)

Amounts due from/(to) related parties are as follows:

December 31,	**2020**	2019
(millions of Canadian dollars)		
Westcoast Energy Inc.[1]	**—**	(656)
Enbridge Inc.[2]	**(68)**	(39)
Enbridge Employee Services Canada Inc.	**(38)**	(46)
NEXUS Gas Transmission, LLC (U.S.)	**(10)**	(10)
Enbridge Pipelines Inc.	**45**	—
Union Energy Solutions Limited Partnership	**29**	23
Other affiliates, net[3]	**7**	(2)
	(35)	(730)

1 Included a $650 million subordinated promissory note from Westcoast, which was repaid in the second quarter of 2020.
2 Includes net derivative payable balances to affiliate.
3 Includes current portion of operating lease liabilities to affiliates.

SHARE CAPITAL
During the year ended December 31, 2020, common share dividends declared on our Class A and Class B common shares were $243 million (2019 - $506 million) and $207 million (2019 - $431 million), respectively. During 2020, we also completed the return of capital transactions, and received capital contributions, as described in *Note 11. Share Capital*.

FINANCING TRANSACTION
On April 1, 2020, we repaid the outstanding $650 million subordinated promissory note, as well as the related interest payable, due to Westcoast

GAS METER SERVICES
We purchase gas meter services from Lakeside Performance Gas Services Ltd. (Lakeside), such as ongoing meter exchanges and inspections for customers in our franchise area. As of December 1, 2020, Lakeside became an affiliate. In the month of December 2020, we purchased gas meter services from Lakeside totaling $3 million, of which a portion of these costs was expensed to Operating and administrative expense and the remainder capitalized in Property, plant and equipment. We will continue purchasing these services at prevailing market prices under normal trade terms.

WHOLESALE SERVICES
We provide gas procurement and transportation services to Gazifère Inc., an affiliate, pursuant to a contract negotiated between us and approved by the OEB and Régie de l’énergie.

LEASES
We incur operating lease payments related to natural gas transportation and storage services from various affiliates. Total affiliate right-of-use assets and lease liabilities as at December 31, 2020 were $51 million (2019 - $43 million) and $51 million (2019 - $43 million), respectively. See *Note 14* for further discussion.

DERIVATIVE INSTRUMENTS
As at December 31, 2020, we had a net payable balance of $36 million (2019 - $22 million) due to Enbridge in respect of derivative instruments that they have entered into on our behalf. See *Note 13. Risk Management and Financial Instruments* for further discussion.

OTHER
Our cash balances are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

20. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2020, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2020, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	8,695	375	125	350	300	745	6,800
Interest obligations[2]	5,521	359	345	342	327	311	3,837
Purchase of services, pipe and other materials, including transportation[3,4]	5,922	1,436	691	536	487	466	2,306
Right-of-way commitments[5]	527	9	9	9	9	9	482
Total	20,665	2,179	1,170	1,237	1,123	1,531	13,425

1 *Includes debentures and term notes, and excludes short-term borrowings, debt discounts, debt issue costs, finance lease obligations and fair value adjustment from push down accounting. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements. Therefore, the actual timing of future cash repayments could be materially different than presented above.*
2 *Includes debentures and term notes bearing interest at fixed rates.*
3 *Includes firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software, consulting or advisory services, as well as customer care services.*
4 *Includes capital and operating commitments.*
5 *Right-of-way payments related to cancellable gas storage payments that are reasonably likely to occur for the remaining life of all storage reservoirs.*

ENVIRONMENTAL

We are subject to various federal, provincial and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to natural gas pipeline operations, and we are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with our operating activities.

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. We were named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by us for the operation of our MGP.

While these Statements of Claim were filed by the City and the School Board, they were never formally served on us. It was and remains our understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, Enbridge Gas and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with us. To our knowledge, neither the City nor the School Board has taken any steps to advance the lawsuits.

Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation, isolation and containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the U.S. for the recovery in rates of costs relating to the remediation of former MGP sites. From 2006 to 2018, the OEB approved the establishment of deferral accounts to record the costs of investigating, defending and dealing with ongoing MGP-related claims. We expect that if it is found that we must contribute to any remediation costs, either as a result of a lawsuit or government order, we would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, we believe that the ultimate outcome of these matters will not have a significant impact on our financial position.

Hamilton Contaminated Site

In April 2016, the Ontario Ministry of the Environment, Conservation and Parks (MECP), formerly the Ministry of the Environment and Climate Change, issued a Director's Order (the Order) naming us, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Enbridge Gas in Hamilton. In May 2016, we appealed the Order, and in June 2016, the Environmental Review Tribunal (the Tribunal), on consent of the MECP's Director, stayed the application of parts of the Order. The Tribunal extended the stay of the Order several times, which has allowed the owner of the property, with the cooperation of the adjacent owners, to prepare a plan of action, including discussions with the MECP and other neighbors. On February 4, 2021, the MECP determined that we and other parties have complied with the Order and no further obligations are outstanding. Accordingly, we withdrew our appeal and the Tribunal has accepted the withdrawal and is closing its file.

OTHER LITIGATION

We are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, page 5, paragraph 9b

Preamble:

"Entities that are covered under Part 2 of the GGPPA, 'Industrial Greenhouse' Gas Emissions", are exempt from coverage under Part 1 of the GGPPA, 'Fuel Charge'. Part 2 entities are instead covered under an OBPS, with mandatory and voluntary participation thresholds, established for prescribed industrial facilities that emit specified volumes of GHG emissions, measured in tCO2e, annually. This component of the GGPPA became effective January 1, 2019."

Questions:

a) Please provide the forecast 2020 and 2021 OBPS/EPS volumes exempted and reconcile to the Exhibits in the evidence.

b) Is this 2021 forecast likely to change? How will EGI deal with this? Please explain.

Response:

a) The OBPS/EPS forecast exempt volumes are shown below.

Forecasted OBPS/EPS Exempt Volumes (10^3m^3)

	EGD Rate Zone	Union Rate Zones
2020	1,391,445	5,856,788
2021	1,574,386	6,381,901
2022	1,552,065	6,595,140

The volumes shown in the table above do not reconcile to the exhibits shown in evidence. The difference between the volumes shown in the table above and the exhibits shown in evidence relates to other exempt volumes, including volumes used by customers in non-covered activities, RNG volumes and partial relief (80%) for greenhouse operators, which are included within the exhibits.

b) Enbridge Gas provides customer exempt volume forecasts for informational purposes only. A variance to the customer exempt volume forecast will have no impact as exempt customers are not charged the Federal Carbon Charge.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, Page 10: and Exhibit C, Table 3

Preamble:

"Enbridge Gas has estimated its 2022 cost of compliance with the GGPPA and EPS Regulation to be approximately $1.68 billion: $1,039.50 million for the EGD rate zone (see Exhibit B, Tab 1 for additional detail) and $644.36 million for the Union rate zones (see Exhibit B, Tab 2 for additional detail). In addition, Enbridge Gas estimates that it will incur 2022 administrative costs of approximately $6.99 million associated with the administration of its requirements under the GGPPA and EPS Regulation (see Exhibit C for additional detail)."

Questions:

a) Please provide a schedule including comparable costs for 2019-21

b) What are the main drivers for admin cost increases e.g. FTE, IT costs etc.

Response:

a) A comparison of Enbridge Gas's cost of compliance with the GGPPA (excluding administration costs) from 2019 to 2022 is provided in Table 1 below. Compliance costs for 2019 and 2020 are actual costs while the 2021 and 2022 compliance costs are forecasts.

Table 1
2019-2022 EGI Cost of Compliance ($millions)

	Actual	Actual	Forecast	Forecast
	2019	2020	2021	2022
Total Cost of Compliance[1] (excluding administration costs)	346.84	809.16	1,365.28	1,683.86

[1] Only costs related to regulated activities are included.

A comparison of the 2019 to 2022 administration costs is provided in the Table 2 below. The administration costs for 2019 and 2020 are actual costs while the 2021 and 2022 administration costs are forecasts.

Table 2
2019-2022 EGI Administration Costs ($millions)

Cost Element	Actual 2019[2]	Actual 2020[3]	Updated Forecast 2021[4]	Updated Forecast 2022[5]
IT Billing System	0.52	0.31	0.22	0.06
Staffing Resources	0.72	0.84	1.10	0.94
Consulting & External Legal Support	0.07	0.13	0.30	0.30
GHG Reporting & Verification	0	0.06	0.05	0.05
Bad Debt	0.13	1.03	2.74	3.72
Other Miscellaneous Costs	0.12	0.04	0.16	0.15
Interest[6]	0.04	0.02	N/A	N/A
Total	**1.6**	**2.44**	**4.57**	**5.21**

b) The main driver for the increase in overall administration costs is an increase in the bad debt related to the Federal Carbon Charge. Enbridge Gas has also had an increase in the costs related to staffing resources, consulting and external legal support. The drivers for increases in each cost element are discussed below.

Costs related to staffing resources have increased due to the number of FTE's who are allocated to the GGEADA, from 4 in 2019 to 5.5 forecasted for 2022, which reflects the incremental level of effort Enbridge Gas has experienced to date and expects to require in 2022 to facilitate compliance with the GGPPA, EPS Regulation and other GHG or carbon pricing regulations. For further information on the costs related to staffing resources, please see Exhibit I.STAFF.4.

The increase in consulting and external legal support in 2020 as compared to 2019 is due to work that was initiated in 2020 to understand the impact of various federal and provincial climate policies. Enbridge Gas increased the forecast amount in 2021 in anticipation of this work continuing, as well as consulting work that would be required related to the proposed Clean Fuel Regulation, offset regulation and

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[2] EB-2019-0247, EGI Updated 2020 Federal Caron Pricing Program Application (May 14, 2020), Exhibit C, p. 6.
[3] EB-2021-0209, EGI 2022 Federal Carbon Pricing Program Application (September 29, 2021), Exhibit C, p. 4. See Exhibit.I.VECC.7 for an explanation on the updated bad debt.
[4] EB-2020-0212, EGI 2021 Federal Carbon Pricing Program Application (September 30, 2020), Exhibit C, p. 4. See Exhibit.I.VECC.7 for an explanation on the updated bad debt.
[5] EB-2021-0209, EGI 2022 Federal Carbon Pricing Program Application (September 29, 2021), Exhibit C, p. 9. Refer to Exhibit I.STAFF.4 for an explanation on the updated staffing resources and Exhibit I.VECC.7 for an explanation on the updated bad debt.
[6] Enbridge Gas did not include a 2021 or 2022 forecast cost for interest.

transition to EPS. Enbridge Gas anticipates the same level of spending on consulting and external legal support may be required in 2022.

Bad debt related to the Federal Carbon Charge has increased due to the annual increase of the Federal Carbon Charge rate and the year over year increase to total Enbridge Gas bad debt. The forecasted increase to total Enbridge Gas bad debt is a function of historic arrear balances, bankruptcy, unemployment, inflation rates and general economic forecasts. Please see Exhibit I.VECC.7 for further information on bad debt.

The other miscellaneous costs have been relatively consistent from 2019-2022, with the exception of 2020 where actual costs were only $0.04 million due to the COVID-19 emergency limiting activities such as travel and conferences. The 2021 and 2022 other miscellaneous costs have been forecasted relative to previous years forecasts which did not include COVID-19 implications.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, pages 14-15, paragraph 37, Table 3

Preamble:

"As discussed in Enbridge Gas' 2021 Application there were four opportunities identified with the potential to reduce OBPS/EPS-volumes."

Questions:

a) What is the Cost of the CEE Plan to date, including non-implemented projects, and projected costs in 2022?

b) Please provide OM&A and savings per year for Monitoring and Air filters.

c) Are there any other opportunities EGI is considering, such as electrification, RNG and compressor replacement? Please list these, provide more details, the estimated costs and GHG reductions for each.

Response:

a) As discussed in Exhibit I.Anwaatin.4 d), all emission reduction opportunities identified as part of the Facility GHG Emissions Reduction Program (which is a continuation of the work completed under the CEE Plan) that have been implemented and those planned for 2022 have been undertaken as part of Enbridge Gas's standard operational maintenance program, and therefore there are no incremental costs included in this Application.

b) Although the costs related to the Online Monitoring and Air Filter opportunities are not being recovered through the FCPP-related deferral and variance accounts, estimated costs and savings have been outlined below.

Opportunity	Costs/Savings to Date		Projected 2022 Costs/Savings	
	Net O&M	Capital	Net O&M	Capital
Online Monitoring	N/A	$45,000	N/A	$5,000
Air Filters	$2,000	N/A	N/A	N/A

c) Further emission reduction opportunities, including electrification and RNG fuel switching are currently being reviewed by Enbridge Gas, along with the development of a plan for compressor unit lifecycle replacement. As part of the analysis of these opportunities, the estimated costs and potential GHG reduction will be determined.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, pages 17-18, paragraphs 42-45

Preamble:

"Enbridge Gas has alternative compliance options to satisfy its annual OBPS and EPS compliance obligation aside from paying the excess emissions charge, including the purchase of Credits, or EPUs from other OBPS or EPS participants, respectively, and in the OBPS purchasing Offset Credits."

Questions:

a) What was the potential cost reduction in 2021 if the EPS system was in place?

b) What is the potential range(s) of credit cost reductions available for 2022? Please provide examples of the calculations.

Response:

a) Please see the response at Exhibit I.STAFF.1.a), in the 2021 Federal Carbon Pricing Program proceeding (EB-2020-0212).

b) The potential range of cost reductions in 2022 will depend on the availability of lower cost compliance options and the price that Enbridge Gas can purchase them at. Generally, credits used for compliance under the Output Based Pricing System, including offset credits and surplus credits, have traded at prices that are $1 to $2 below the rate of the excess emissions charge. However, the cost of transacting for these credits must also be factored in.

   Under the current EPS, only EPUs can be used to satisfy a regulated entity's compliance obligation. Enbridge Gas anticipates that EPUs will also trade at a discount to the excess emissions charge. However, given this is a new market the exact value and availability of EPUs, and the cost of transacting for these credits, are yet to be seen. As such, Enbridge is unable to provide a range of possible cost reductions for 2022.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, page 18, paragraph 43

Preamble:

"With market prices of Offset Credits in Alberta expected to increase in the fourth quarter of 2020, Enbridge Gas did not have enough time to take the required steps to procure Offset Credits from Alberta below the 2020 excess emissions charge of \$30/tCO2e."

Question:

Please list the steps required to procure Offset Credits from Alberta and the time required for each step.

Response:

In order to procure Offset Credits from Alberta, the following steps are generally required:

1. Register for an account in the Alberta Emission Offset Registry ("AEOR");
2. Develop an emission trading master agreement;
3. Identify a counter party offering offset credits for sale and agree on the framework for a transaction with such party;
4. Complete internal counterparty review and diligence;
5. Assuming steps 3 and 4 can be completed successfully, complete contracting processes;
6. Take delivery of offset credits on the AEOR;

Although there is no set timing for each step, in practice Enbridge Gas has found this process to take several months or longer to complete, as it requires steps to be taken by the AEOR and contract counterparties that are outside of Enbridge Gas's control. In addition, Alberta offset credits can only be transferred to a buyer's account once they have been serialized and registered on the AEOR in accordance with the Technology Innovation and Emissions Reduction ("TIER") Regulation. Because sellers often require buyers to transact for the future delivery of offset credits that have not yet been registered, the length of time between steps 5 and 6 alone can last several months.

The trading price of Alberta offset credits rose higher than the excess emissions charge of \$30/tCO2e in early November 2020, ahead of the annual price increase in the TIER program. This was less than two months after Environment and Climate Change Canada's August 25, 2020 announcement that facilities with a compliance obligation under the OBPS could procure Alberta offset credits for OPBS compliance, which was not enough time to complete the steps above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit A, Tab 2, Page 19, paragraphs 46-47

Preamble:

"The bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,400 m3 is an increase of $47.05 per year in the EGD rate zone. The bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,400 m3 is $0.76 in the EGD rate zone."

Questions:

a) What is the total amount of carbon charges for a typical residential EGD rate zone customer with annual consumption of 2,400 m3 including the $47.05 increase and the $0.76 disposition, and the amounts approved in previous years?

b) What is the percentage of the total amount of carbon charge compared to the commodity cost for a system gas EGD rate zone customer based on the latest QRAM commodity price?

Response:

a) Please see Table 1 which shows the average Rate 1 residential bill impact for the Federal Carbon Charge and Facility Carbon Charge since 2019, including the impact of the 2022 carbon charge for a typical residential customer with annual consumption of 2,400 m^3. Table 2 shows the breakdown of the FCPP-related deferral and variance account balance disposition amounts since 2019.

Table 1
Residential Annual Bill Impacts from Carbon Charges for the EGD Rate Zone
Effective April 1 of Each Year

Carbon Charge	Annual Bill Impact				Total
	2022 Proposed (1)	2021 Approved (2)	2020 Approved (3)	2019 Approved (4)	
	($)	($)	($)	($)	($)
Federal	47.04	47.04	47.04	93.84	234.96
Facility	0.01	0.04	0.03	0.09	0.17
Total	47.05	47.08	47.07	93.93	235.13

Notes:
(1) Exhibit D, Tab 1, Schedule 2, page 2.
(2) EB-2020-0212, Exhibit D, Tab 1, Schedule 2, page 2.
(3) EB-2019-0247, Exhibit D, Tab 1, Schedule 2, page 2 (Updated May 14, 2020).
(4) EB-0218-0187/EB-2018-0205, Exhibit E, Tab 1, Schedule 2, page 2 (Updated November 1, 2019).

Table 2
FCPP Related-Deferral and Variance Account
Balance Disposition Amount for Rate 1 (EGD Rate Zone)

Deferral/Variance Account	2020 Disposition		2019 Disposition	
	Unit Rate (1)	Disposition Amount (2)	Unit Rate (3)	Disposition Amount (2)
	(¢/m^3)	($)	(¢/m^3)	($)
Customer-Related	0.0000	0.00	-	-
Facility-Related	(0.0003)	(0.01)	-	-
GGEADA	0.0301	0.72	0.0922	0.49
Total	0.0298	0.72	0.0922	0.49

Notes:
(1) Exhibit D, Tab 1, Schedule 4, page 5, (Corrected December 15, 2021).
(2) 2020 unit rate x annual volume of 2,400 m^3.
(3) EB-2019-0247, Draft Rate Order, Appendix B, page 3 (August 20, 2020).
(4) 2019 unit rate x April to July volume of 530 m^3 (the unit rate is applied to customer's consumption from April to July).

Please note, Table 2 excludes the 2019 Customer-related and Facility-related deferral account balances. The 2019 Federal Carbon Charge became effective April 1, 2019, however the rate increases were not approved for implementation until

August 1, 2019. As such, including the 2019 Customer-related and Facility-related amounts in Table 2 would result in double counting of carbon charge from Table 1. The bill impact provided in Table 1 for 2019 ($93.93) is representative of a full year impact of the Federal Carbon Charges and Facility Carbon Charges.

b) Please see Table 3 below for a comparison of the total amount of carbon charge as a percentage of the commodity cost for a system gas EGD rate zone customer based on the October 2021 QRAM commodity price.

Table 3
Comparison of 2022 Carbon Charges and Commodity Cost based on October 2021 QRAM

Carbon Charge	Carbon Charge Amount (1)	Commodity Cost (1)	% of Commodity Cost
	($)	($)	(%)
Federal	234.96	358.13	65.6%
Facility	0.17	358.13	0.0%
Total	235.13	358.13	65.7%

Note:
(1) Exhibit D, Tab 1, Schedule 2, page 2 (Facility Carbon charge is embedded in distribution charge).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, page 4, paragraph 13.

Preamble:

"Volumes of RNG in OptUp were incorporated into the 2022 Customer-Related Volume forecasts based on the forecast provided in Exhibit C, Tab 2, Schedule 3 of the Voluntary Renewable Natural Gas Program Application (EB-2020-0066)."

Questions:

a) How many customers were registered in OptUp in 2020 and 2021 and forecast for 2022?

b) What was the average price and price premium $/m3?

c) What was the 2021 GHG reduction and cost/MTeqiv.?

Response:

a) Enbridge Gas did a soft launch for OptUp in April 2021 and a broader launch in June 2021. No customers were registered in OptUp in 2020; 619 customers were registered as of November 30, 2021; and Enbridge Gas is working towards achieving the year 2 forecast of 23,000 participants.[1]

b) To date, Enbridge Gas has not purchased any RNG for the Voluntary RNG program and therefore has not paid a premium.

c) As Enbridge Gas has yet to purchase any RNG for the Voluntary RNG program, there have been no associated GHG reductions in 2021.

[1] EB-2020-0066, EGI Voluntary Renewable Natural Gas Program Application, Exhibit C, Tab 2, Schedule 1.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 1, Schedules 2 and 5 and Exhibit D, Table 1

Questions:

a) Why is there no Non-utility Forecast Amount for Company Use facilities? Which facilities do Unregulated Volumes use?

b) For EPS compressor fuel, how are the non-utility fuel volumes calculated? Are they separated from utility compressor fuel? Please discuss/clarify.

c) Please show for 2021, how forecast utility compressor fuel volumes and the Facilities Carbon Charge are recovered in rates, including separation of the Non-utility volumes.

Response:

a) – c)

Please refer to the response at Exhibit I.EP.9 a-c, in Enbridge Gas's 2021 Federal Carbon Pricing Program Application (EB-2020-0212).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit B, Tab 2, Schedules 2 and 5

Questions:

a) Why is there no Non-utility Forecast Amount for Boilers/Line heaters and NGV Fleet? Which facilities other than Buildings do Unregulated Volumes use?

b) For compressor fuel, how are the non-utility fuel volumes reported? Are they separated from utility compressor fuel?

c) Please show for 2021 how forecast utility compressor fuel volumes and the Facilities Carbon Charge are recovered in rates, including separation of the Non-utility volumes.

Response:

a) – c)

Please refer to the response at Exhibit I.EP.12 in Enbridge Gas's 2021 Federal Carbon Pricing Program Application (EB-2020-0212).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit C, page 11, paragraph 30

Preamble:

"Enbridge Gas anticipates that it will incur $0.30 million in consulting and external legal costs in 2022 for work supporting the development and sustainment of Enbridge Gas's carbon strategy and related analyses,…"

Questions:

a) What is the objective of "Enbridge Gas's carbon strategy"?

b) Will Enbridge's shareholders benefit from Enbridge's carbon strategy?

c) Of the $0.30 million, what amount is expected to be spent on work "supporting the development and sustainment of Enbridge Gas carbon strategy and related analyses"?

Response:

a) The objective of the Enbridge Gas carbon strategy is to develop compliance strategies for, and maintain compliance with, the Federal carbon pricing Program, Ontario's Emission Performance Standards, and any other GHG or climate policies or carbon pricing programs that may apply to Enbridge Gas's business.

b) Enbridge Gas, its shareholders and ratepayers benefit from the company complying with applicable carbon pricing programs and climate policies. Cost savings that may be gained by implementing lower cost compliance options, such as the procurement of offset credits or the implementation of cost-effective emission reduction opportunities, where such credits and opportunities are available, would benefit ratepayers by lowering compliance costs for the regulated business.

c) Please refer to the response at Exhibit I.Anwaatin.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe (EP)

Interrogatory

Reference:

Exhibit D, Tab1 Schedule 2

Questions:

a) Please provide the 2020 vs 2021 EGD Rate Zone Residential Bill impacts per Exhibit D Tab 1, Schedule 2 with the Facilities and OBS charges shown as separate lines.

b) Please confirm which items are currently specifically identified on the EGD RZ Rate 1 Customer Bill e.g. FCPP Charge, Facilities Charge, OBS amount.

Response:

a) The 2021 vs 2022 bill impact changes for the Facility Carbon Charge and Federal Carbon Charge are provided at Exhibit D, Tab 1, Schedule 2 for the EGD rate zone. The Facility Carbon Charge is embedded in the distribution charge. As such, the change in the distribution charge is equal to the change in the Facility Carbon Charge.

   The Facility Carbon Charge is calculated as the total Facility Carbon Costs divided by the total forecast volumes for all rate classes (EB-2021-0209, Exhibit D, Tab 1, Schedule 1, page 2).

   Table 1 below shows the proportion of the Facility Carbon Charge that is related to Company Use and to the EPS obligation for the EGD rate zone.[1] The percent of total facility-related costs shown in Table 1 can be applied to the distribution charge bill impacts to determine the applicable component (Company Use or EPS obligation) of the Facility Carbon Charge for all rate classes and customer profiles.

[1] On September 21, 2020, the province of Ontario announced that the federal government accepted Ontario's carbon pricing system for industrial emitters, known as the Ontario Emissions Performance Standards ("EPS") program, as an alternative to the federal OBPS. Effective January 1, 2022 the EPS will replace the OBPS in Ontario.

Table 1
2022 Facility Carbon Charge Breakdown for the EGD Rate Zone

Line No.	Particulars	Facility Carbon Cost ($) (1)	Percent of Total Facility Costs (%)	Facility Carbon Charge Unit Rate (¢/m^3)
1	Company Use	582,086	54%	0.0038
2	EPS Obligation	503,434	46%	0.0032
3	Total Facility Related Costs	1,085,520	100%	
4	Facility Carbon Charge Unit Rate (1)			0.0070

Notes
(1) Exhibit D, Tab 1, Schedule 1, p. 2.

b) The Federal Carbon Charge is currently shown as a separate line item on Rate 1 customers' bills and the Facility Carbon Charge is embedded in the delivery charge on Rate 1 customers' bills for the EGD rate zone. Please see Table 1 above for the breakdown of the Facility Carbon Charge, which includes Enbridge Gas's EPS obligation.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, pages 12

Question:

"Customers that hold an Exemption Certificate must provide a copy to Enbridge Gas no later than two weeks in advance of the first day of the month in which they wish to have their consumption volumes exempted from the Federal Carbon Charge"

a) If a customer remits a Certificate after the deadline described above but for which the Certificate covers a prior period are they eligible for a refund? If so is this an adjustment made to the variance account for this change?

Response

a) Further information on Enbridge Gas's exemption process, is provided in the pre-filed evidence at Exhibit B, page 3:

> For those customers covered under the EPS or undertaking non-covered activities, Enbridge Gas will exempt the customer on the date provided by the CRA on the customer's CRA-issued registration confirmation letter. For customers operating commercial greenhouses, exemption will begin the first day of the calendar month following the month in which they provide Enbridge Gas with their Exemption Certificate.

If a customer covered under the OBPS/EPS or undertaking a non-covered activity has provided the Exemption Certificate after the date on the CRA-issued registration confirmation letter has passed, a billing adjustment is completed. This adjustment is also captured in Enbridge Gas's monthly Federal Carbon Charge remittance to the CRA, therefore no adjustment to the customer variance accounts is required.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1, page 8.

Question:

EGI explains that: "*Certain aspects of this transition have not yet been finalized by the relevant governmental authorities and may ultimately impact the costs incurred by Enbridge Gas in complying with the GGPPA and EPS*"

a) Please explain what aspects have not been finalized and how they impact the implementation of EGI's compliance with the GGPPA and EPS.

b) EGI notes that any cost impacts due to change in the estimated EPS compliance obligation will be included in the Facility Carbon Charge – Variance Account. Does EGI have an estimate of the possible range of costs that might be incurred due to this uncertainty?

Response

a) All aspects of the EPS and the transition from OBPS to EPS have now been finalized. Please refer to Exhibit I.STAFF.1 for a discussion of the updates related to the EPS that have occurred since the application was filed.

b) The updates discussed in Exhibit I.STAFF.1 have no impact on Enbridge Gas's forecasted 2022 EPS compliance obligation included in the pre-filed evidence and will not create a cost variance within the Facility Carbon Charge – Variance Accounts.

ENBRIDGE GAS INC.

Answer to Interrogatory from Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1

Questions:

	Opportunity	Total Estimated Capital Cost ($millions)	Estimated Emissions Reductions – 2020 (tCO2e)	Forecasted Emissions Reductions – 2022 (tCO2e)	Forecasted Emissions Reductions – 10-yr Cumulative (tCO2e)	Cost per Tonne of GHG Emissions ($/tCO2e)[26]
1	Online Monitoring	0.05	218	N/A[27]	1,100	-32
2	Air Filters	0[28]	0[29]	184	1,500	-47[30]
3	Plant J Twinning (Electric Drive)	70.00	N/A[31]	N/A	N/A	105
4	Re-wheeling Turbines	17.19	N/A[32]	N/A	N/A	191

a) Please provide the cost-benefit analysis that was undertaken for projects 3 (Plant J) and project 4 (Re-wheeling).

b) Are there any projects being planned and for which costs are currently being booked to account for future recovery? If so please detail these and provide an estimate of the annual costs for each of the next two years.

Response

a) Please see Attachment 1 for the distributed cash flow analysis for the Plant Twinning and Re-wheeling opportunities.

b) There are currently no costs being booked for future recovery.

Plant J Twinning (Electric Drive)

	1	2	3	4	5	6	7	8	9	10	11
Start of Period	1-Jul-2021	1-Jul-2022	1-Jul-2023	1-Jul-2024	1-Jul-2025	1-Jul-2026	1-Jul-2027	1-Jul-2028	1-Jul-2029	1-Jul-2030	1-Jul-2031
End of Period	30-Jun-2022	30-Jun-2023	30-Jun-2024	30-Jun-2025	30-Jun-2026	30-Jun-2027	30-Jun-2028	30-Jun-2029	30-Jun-2030	30-Jun-2031	30-Jun-2032
<u>**Cash Inflows**</u>											
Revenue	-	-	-	-	-	-	-	-	-	-	-
O&M Expense	-	-	(1,248,580)	(1,167,781)	(1,086,981)	(1,006,182)	(925,383)	(844,583)	(763,784)	(682,985)	(682,985)
Income Tax Expense	-	-	4,504,624	2,465,899	2,121,022	1,824,664	1,569,549	1,349,488	1,159,226	994,290	872,295
Total Cash Inflows	**-**	**-**	**3,256,044**	**1,298,119**	**1,034,041**	**818,482**	**644,166**	**504,905**	**395,441**	**311,306**	**189,311**
<u>**Cash Outflows**</u>											
Capital Expenditures	70,000,000	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	63,069	(4,081)	(4,081)	(4,081)	(4,081)	(4,081)	(4,081)	(4,081)	-
Total Cash Outflows	**70,000,000**	**-**	**63,069**	**(4,081)**	**(4,081)**	**(4,081)**	**(4,081)**	**(4,081)**	**(4,081)**	**(4,081)**	**-**
Net CF Undiscounted	(70,000,000)	-	3,192,975	1,302,200	1,038,122	822,564	648,247	508,986	399,523	315,387	189,311
Net CF Cumulative (Undiscounted)	(70,000,000)	(70,000,000)	(66,807,025)	(65,504,825)	(64,466,703)	(63,644,140)	(62,995,892)	(62,486,906)	(62,087,383)	(61,771,996)	(61,582,685)
Cum'ltive PV Net Inflow	-	-	2,926,014	4,043,583	4,896,529	5,543,400	6,031,187	6,397,469	6,672,330	6,879,650	7,000,446
Cum'ltive PV Net Capital	70,000,000	70,000,000	70,057,898	70,054,309	70,050,870	70,047,575	70,044,417	70,041,393	70,038,495	70,035,718	70,035,718
Cumulative NPV of Cash Flows	**(70,000,000)**	**(70,000,000)**	**(67,131,884)**	**(66,010,726)**	**(65,154,341)**	**(64,504,175)**	**(64,013,230)**	**(63,643,924)**	**(63,366,165)**	**(63,156,068)**	**(63,035,272)**
Project NPV, Proj Life Years = 40	**(66,481,116)**										

Plant J Twinning (Electric Drive)

	12	13	14	15	16	17	18	19	20	21	22	23
Start of Period	1-Jul-2032	1-Jul-2033	1-Jul-2034	1-Jul-2035	1-Jul-2036	1-Jul-2037	1-Jul-2038	1-Jul-2039	1-Jul-2040	1-Jul-2041	1-Jul-2042	1-Jul-2043
End of Period	30-Jun-2033	30-Jun-2034	30-Jun-2035	30-Jun-2036	30-Jun-2037	30-Jun-2038	30-Jun-2039	30-Jun-2040	30-Jun-2041	30-Jun-2042	30-Jun-2043	30-Jun-2044
Cash Inflows												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
O&M Expense	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)
Income Tax Expense	768,600	680,458	605,538	541,856	487,726	441,716	402,607	369,365	341,109	317,091	296,676	279,323
Total Cash Inflows	**85,615**	**(2,526)**	**(77,446)**	**(141,129)**	**(195,258)**	**(241,269)**	**(280,377)**	**(313,620)**	**(341,876)**	**(365,894)**	**(386,309)**	**(403,661)**
Cash Outflows												
Capital Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net CF Undiscounted	85,615	(2,526)	(77,446)	(141,129)	(195,258)	(241,269)	(280,377)	(313,620)	(341,876)	(365,894)	(386,309)	(403,661)
Net CF Cumulative (Undiscounted)	(61,497,070)	(61,499,597)	(61,577,043)	(61,718,172)	(61,913,430)	(62,154,699)	(62,435,076)	(62,748,696)	(63,090,572)	(63,456,466)	(63,842,775)	(64,246,436)
Cum'ltive PV Net Inflow	7,052,782	7,051,303	7,007,841	6,931,959	6,831,380	6,712,304	6,579,720	6,437,626	6,289,233	6,137,065	5,983,133	5,829,021
Cum'ltive PV Net Capital	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718
Cumulative NPV of Cash Flows	**(62,982,935)**	**(62,984,415)**	**(63,027,876)**	**(63,103,759)**	**(63,204,338)**	**(63,323,414)**	**(63,455,998)**	**(63,598,092)**	**(63,746,485)**	**(63,898,653)**	**(64,052,585)**	**(64,206,696)**

Project NPV, Proj Life Years = 40

Plant J Twinning (Electric Drive)

	24	25	26	27	28	29	30	31	32	33	34	35
Start of Period	1-Jul-2044	1-Jul-2045	1-Jul-2046	1-Jul-2047	1-Jul-2048	1-Jul-2049	1-Jul-2050	1-Jul-2051	1-Jul-2052	1-Jul-2053	1-Jul-2054	1-Jul-2055
End of Period	30-Jun-2045	30-Jun-2046	30-Jun-2047	30-Jun-2048	30-Jun-2049	30-Jun-2050	30-Jun-2051	30-Jun-2052	30-Jun-2053	30-Jun-2054	30-Jun-2055	30-Jun-2056
Cash Inflows												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
O&M Expense	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)
Income Tax Expense	264,573	252,036	241,379	232,321	224,622	218,077	212,514	207,786	203,766	200,350	197,446	194,978
Total Cash Inflows	**(418,411)**	**(430,949)**	**(441,605)**	**(450,664)**	**(458,363)**	**(464,908)**	**(470,471)**	**(475,199)**	**(479,218)**	**(482,635)**	**(485,539)**	**(488,007)**
Cash Outflows												
Capital Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
Total Cash Outflows	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net CF Undiscounted	(418,411)	(430,949)	(441,605)	(450,664)	(458,363)	(464,908)	(470,471)	(475,199)	(479,218)	(482,635)	(485,539)	(488,007)
Net CF Cumulative (Undiscounted)	(64,664,847)	(65,095,796)	(65,537,401)	(65,988,065)	(66,446,428)	(66,911,336)	(67,381,807)	(67,857,006)	(68,336,225)	(68,818,859)	(69,304,398)	(69,792,405)
Cum'ltive PV Net Inflow	5,675,985	5,524,963	5,376,685	5,231,702	5,090,433	4,953,146	4,820,034	4,691,213	4,566,756	4,446,660	4,330,901	4,219,424
Cum'ltive PV Net Capital	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718
Cumulative NPV of Cash Flows	**(64,359,733)**	**(64,510,755)**	**(64,659,033)**	**(64,804,016)**	**(64,945,285)**	**(65,082,572)**	**(65,215,684)**	**(65,344,505)**	**(65,468,962)**	**(65,589,058)**	**(65,704,817)**	**(65,816,293)**

Project NPV, Proj Life Years = 40

Plant J Twinning (Electric Drive)

	36	**37**	**38**	**39**	**40**	**41**	**42**
Start of Period	1-Jul-2056	1-Jul-2057	1-Jul-2058	1-Jul-2059	1-Jul-2060	1-Jul-2061	1-Jul-2062
End of Period	30-Jun-2057	30-Jun-2058	30-Jun-2059	30-Jun-2060	30-Jun-2061	30-Jun-2062	30-Jun-2063
Cash Inflows							
Revenue	-	-	-	-	-	-	-
O&M Expense	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)	(682,985)
Income Tax Expense	192,880	191,097	189,581	188,292	187,197	186,266	185,475
Total Cash Inflows	**(490,105)**	**(491,888)**	**(493,404)**	**(494,693)**	**(495,788)**	**(496,719)**	**(497,510)**
Cash Outflows							
Capital Expenditures	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-
Total Cash Outflows	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net CF Undiscounted	(490,105)	(491,888)	(493,404)	(494,693)	(495,788)	(496,719)	(497,510)
Net CF Cumulative (Undiscounted)	(70,282,510)	(70,774,398)	(71,267,802)	(71,762,494)	(72,258,282)	(72,755,001)	(73,252,511)
Cum'ltive PV Net Inflow	4,112,169	4,009,030	3,909,906	3,814,683	3,723,257	3,635,493	3,554,602
Cum'ltive PV Net Capital	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718	70,035,718
Cumulative NPV of Cash Flows	**(65,923,549)**	**(66,026,688)**	**(66,125,812)**	**(66,221,035)**	**(66,312,461)**	**(66,400,224)**	**(66,481,116)**

Project NPV, Proj Life Years = 40

Re-Wheeling Turbines

	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Start of Period	1-Jun-2020	1-Jun-2021	1-Jun-2022	1-Jun-2023	1-Jun-2024	1-Jun-2025	1-Jun-2026	1-Jun-2027	1-Jun-2028	1-Jun-2029	1-Jun-2030	1-Jun-2031
End of Period	31-May-2021	31-May-2022	31-May-2023	31-May-2024	31-May-2025	31-May-2026	31-May-2027	31-May-2028	31-May-2029	31-May-2030	31-May-2031	31-May-2032
Cash Inflows												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
O&M Expense	13,142	28,727	45,850	60,652	60,652	60,652	60,652	60,652	60,652	60,652	60,652	60,652
Income Tax Expense	354,267	447,127	793,132	632,658	441,697	350,143	276,900	218,305	171,430	133,929	103,929	79,929
Total Cash Inflows	**367,409**	**475,854**	**838,982**	**693,309**	**502,348**	**410,794**	**337,551**	**278,957**	**232,081**	**194,581**	**164,580**	**140,580**
Cash Outflows												
Capital Expenditures	4,500,000	3,620,000	6,760,000	2,310,000	-	-	-	-	-	-	-	-
Change in Working Capital	(664)	(787)	(865)	(748)	-	-	-	-	-	-	-	-
Total Cash Outflows	**4,499,336**	**3,619,213**	**6,759,135**	**2,309,252**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net CF Undiscounted	(4,131,927)	(3,143,359)	(5,920,153)	(1,615,943)	502,348	410,794	337,551	278,957	232,081	194,581	164,580	140,580
Net CF Cumulative (Undiscounted)	(4,131,927)	(7,275,286)	(13,195,439)	(14,811,382)	(14,309,034)	(13,898,239)	(13,560,688)	(13,281,731)	(13,049,650)	(12,855,069)	(12,690,488)	(12,549,908)
Cum'ltive PV Net Inflow	359,108	803,374	1,551,572	2,142,162	2,550,862	2,870,103	3,120,673	3,318,470	3,475,638	3,601,507	3,703,201	3,786,173
Cum'ltive PV Net Capital	4,499,336	7,956,412	14,123,508	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101
Cumulative NPV of Cash Flows	**(4,140,228)**	**(7,153,038)**	**(12,571,936)**	**(13,993,938)**	**(13,585,238)**	**(13,265,997)**	**(13,015,428)**	**(12,817,630)**	**(12,660,462)**	**(12,534,593)**	**(12,432,900)**	**(12,349,928)**
Project NPV, Proj Life Years = 24	**(11,980,088)**											

	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Start of Period	1-Jun-2032	1-Jun-2033	1-Jun-2034	1-Jun-2035	1-Jun-2036	1-Jun-2037	1-Jun-2038	1-Jun-2039	1-Jun-2040	1-Jun-2041	1-Jun-2042	1-Jun-2043
End of Period	31-May-2033	31-May-2034	31-May-2035	31-May-2036	31-May-2037	31-May-2038	31-May-2039	31-May-2040	31-May-2041	31-May-2042	31-May-2043	31-May-2044
Cash Inflows												
Revenue	-	-	-	-	-	-	-	-	-	-	-	-
O&M Expense	60,652	60,652	60,652	60,652	60,652	60,652	60,652	60,652	40,370	25,788	14,802	-
Income Tax Expense	60,728	45,368	33,080	23,249	15,385	9,093	4,060	34	2,187	3,474	4,324	6,597
Total Cash Inflows	**121,380**	**106,020**	**93,732**	**83,901**	**76,037**	**69,745**	**64,712**	**60,685**	**42,557**	**29,262**	**19,126**	**6,597**
Cash Outflows												
Capital Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	-	-	-	-	-	-	-	-	1,024	737	555	748
Total Cash Outflows	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,024**	**737**	**555**	**748**
Net CF Undiscounted	121,380	106,020	93,732	83,901	76,037	69,745	64,712	60,685	41,532	28,526	18,571	5,849
Net CF Cumulative (Undiscounted)	(12,428,528)	(12,322,509)	(12,228,777)	(12,144,876)	(12,068,840)	(11,999,095)	(11,934,383)	(11,873,698)	(11,832,165)	(11,803,639)	(11,785,069)	(11,779,219)
Cum'ltive PV Net Inflow	3,854,595	3,911,681	3,959,889	4,001,109	4,036,786	4,068,046	4,095,750	4,120,566	4,137,188	4,148,105	4,154,920	4,157,166
Cum'ltive PV Net Capital	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,101	16,136,510	16,136,791	16,136,993	16,137,254
Cumulative NPV of Cash Flows	**(12,281,506)**	**(12,224,420)**	**(12,176,211)**	**(12,134,992)**	**(12,099,314)**	**(12,068,055)**	**(12,040,351)**	**(12,015,534)**	**(11,999,322)**	**(11,988,686)**	**(11,982,073)**	**(11,980,088)**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1

Questions:

a) Does EGI expect that GHG Emission Reduction and OBPS/EPS program cost delivery will form a distinct part of its upcoming cost of service application and with detailed supporting evidence?

b) If yes, can EGI provide an outline of the expected areas to be addressed in that evidence.

Response

a) and b)

Enbridge Gas is currently considering how GHG emission reductions and carbon pricing costs will be addressed in the upcoming cost of service application. At this point in time, the specific approach for addressing these matters in the evidence has not yet been determined.

ENBRIDGE GAS INC.

Answer to Interrogatory from Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit C

Questions:

Table 1
2020 Administration Costs ($millions)

Cost Element	2020 Forecasted Costs[9]	2020 Actual Costs[10]			Variance
		EGD Rate Zone	Union Rate Zones	Total	
IT Billing System	0.40	0.17	0.14	0.31	(0.09)
Staffing Resources	0.80	0.52	0.32	0.84	0.04
Consulting and External Legal Support	0.20	0.08	0.05	0.13	(0.07)
GHG Reporting and Verification	0.10	0.04	0.02	0.06	(0.04)
Bad Debt	1.84	0.84	0.29	1.13	(0.71)
Other Miscellaneous Costs	0.20	0.02	0.01	0.04	(0.16)
Interest[11]	N/A	0.02	0.01	0.02	0.02
Total	**3.54**	**1.70**	**0.85**	**2.54**	**(1.00)**

Table 3
Forecast 2022 Administration Costs

Cost Element	2022 Forecast Costs ($millions)		
	EGD Rate Zone	Union Rate Zones	Total
IT Billing System	0.00	0.06	0.06
Staffing Resources	0.91	0.56	1.47
Consulting & External Legal Support	0.19	0.11	0.30
GHG Reporting & Verification	0.03	0.02	0.05
Bad Debt	3.47	1.49	4.96
Other Miscellaneous Costs	0.09	0.06	0.15
Total	**4.69**	**2.30**	**6.99**

a) Please provide a table showing the 2021 GGEADA forecast balances.

b) Are the 2020 balances the first time the GGEADA account has been proposed for disposition?

c) Has the Board ordered annual disposition of this account and if not, what impediments are there to disposition of the account at the time of rebasing?

Response

a) Table 1 below shows the forecast 2021 Administration Costs. The forecasts below are explained further in Enbridge Gas's 2021 Federal Carbon Pricing Program Application (EB-2020-0212), at Exhibit C, pages 3 to 7. The 2021 bad debt forecast below has been updated from what was included in EB-2020-0212. Please refer to Exhibit I.VECC.7 for further explanation on the update to the bad debt forecast.

Table 1
Forecast 2021 Administration Costs

Cost Element	2021 Forecast Costs ($millions)		
	EGD Rate Zone	Union Rate Zones	Total
IT Billing System	0.12	0.10	0.22
Staffing Resources	0.67	0.43	1.10
Consulting & External Legal Support	0.18	0.12	0.30
GHG Reporting & Verification	0.03	0.02	0.05
Bad Debt	1.82	0.92	2.74
Other Miscellaneous Costs	0.10	0.06	0.16
Total	**2.92**	**1.65**	**4.57**

b) No. The 2019 FCPP-related deferral and variance accounts were approved for disposition by the OEB.[1]

c) The OEB supported Enbridge Gas's proposal to dispose of FCPP-related deferral and variance accounts annually, on a one-year lag.[2]

[1] EB-2019-0247, OEB Decision and Order, September 3, 2020.
[2] Ibid, August 13, 2020, pp. 20 – 21.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit A, Tab 2, Schedule 1

Questions:

a) What initiatives have EGI introduced to limit the costs for administration of the GHG programs?

Response

Enbridge Gas has taken the following actions to minimize the cost of administration of GHG related programs:

- Consulting and legal support costs have been minimized by leveraging internal staff to complete work wherever possible and appropriate.
- Staffing costs have been reduced by leveraging existing internal resources outside of the Carbon Strategy team, where reasonable to do so.
- Customer communication costs have been minimized by leveraging existing customer communication pathways, such as QRAM bill inserts, mass emails, webpages and social media to communicate to customers.
- Billing system costs related to implementation of the Federal Carbon Charge were minimized by repurposing the changes made in the billing system to collect Cap and Trade related charges.

Enbridge Gas also notes that the costs related to travel, conferences and training were minimized in 2020 due to the COVID-19 pandemic.

Additional initiatives to minimize the cost of administration of GHG related programs in 2019 were discussed in Enbridge Gas's 2020 Federal Carbon Pricing Program Application (EB-2019-0247), in Exhibit I.STAFF.5.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Interrogatory

Reference:

Exhibit C, pages 6, 12

Questions:

a) Please explain how the bad debt figures (2020 and 2022 forecast) attributable to the carbon tax is calculated and distinguished from "regular" (i.e., forecasted into rates) bad debt due to circumstances and regulatory requirements related to COVID-19 and winter moratorium bad debt?

Response

a) During the preparation of this interrogatory response, Enbridge Gas determined that the methodology used to determine the portion of bad debt that is related to the FCPP needed to be corrected in one aspect to ensure accuracy, as detailed below.

The methodology that was used previously calculated a % revenue increase due to the FCPP, based on the total FCPP charges billed divided by the total Company revenue excluding the FCPP charges billed. The corrected methodology is based on the total FCPP charges billed divided by the total Company revenue including the FCPP charges billed. The difference between these methodologies is immaterial when the Federal Carbon Charge rate is low, but as the Federal Carbon Charge rate increases, the difference would become significant.

The previous methodology is shown below and discussed further in EB-2019-0247, Exhibit I.STAFF.7.

2020 FCPP Charges Billed =
2020 Customer Volumes x Federal Carbon Charge Rate

2020 % Revenue Increase =
2020 FCPP Charges Billed ÷ 2020 Forecasted Company Revenue

2020 Federal Carbon Bad Debt =
2020 % Revenue Increase x 2020 Forecasted Company Bad Debt

The updated methodology used to distinguish Federal Carbon bad debt from "regular" bad debt is outlined below.

2020 FCPP Charges Billed =
2020 Customer Volumes Subject to FCPP x Federal Carbon Charge Rate

2020 % of Bill Related to FCPP =
2020 FCPP Charges Billed ÷ Total Company Revenue (including FCPP charges)

2020 Federal Carbon Bad Debt =
2020 % of Bill Related to FCPP x 2020 Company Bad Debt

Updating the methodology has an impact on 2020 actual bad debt for the EGD rate zone and forecasted bad debt for both the EGD rate zone and Union rate zones in 2021 and 2022. The previous methodology was not used to calculate 2020 actuals in the Union rate zones and therefore no update is required. The updated Federal Carbon Bad Debt amounts are shown below for each affected year.

Updated Federal Carbon Bad Debt ($millions)

	2020		2021		2022	
	Actual		Forecasted		Forecasted	
	Previous	Corrected	Previous	Corrected	Previous	Corrected
EGD Rate Zone	0.84	0.74	1.32	1.82	3.47	2.61
Union Rate Zones	N/A	N/A	1.26	0.92	1.49	1.10
Total EGI	N/A	N/A	2.58	2.74[1]	4.96	3.72

As a result of this update, Enbridge Gas has decreased the 2020 administration costs and interest recorded in the EGD rate zone GGEADA to $1.59 million (previously $1.70 million).[2]

[1] The update to Enbridge Gas's 2021 forecast bad debt is an increase of $0.16 million from what was included in EB-2020-0212, Exhibit C, pa 4. Since filing the 2021 FCPP Application in September 2020, the total Company forecast bad debt has increased. The increased forecast has been used in calculating the above updated Federal Carbon bad debt amounts, which caused the forecast bad debt related to the FCPP to increase despite the update to the FCPP allocation methodology. Accordingly, Enbridge Gas has updated the 2021 forecast bad debt to $2.74 million.
[2] The $1.59 million includes $0.01 million of interest.

As a result of this update, the forecast 2021 administration costs for Enbridge Gas have been updated to $4.57.

As a result of this update, the forecast 2022 administration costs for Enbridge Gas have been updated to $5.21 million.[3]

For 2020, a bad debt amount as a result of COVID-19 was distinguished and excluded from the GGEADA calculation as per the OEB's Decision and Order on Enbridge Gas's 2020 Application.[4] For 2021 and 2022 forecasts, no amount has been excluded as a result of COVID-19. Enbridge Gas will assess the impacts of COVID-19 on an actual basis when finalizing GGEADA account balances and adjust as needed.

[3] The $5.21 million also includes an update to the 2022 forecasted staffing costs. The updated forecast is $0.94 million, a reduction of $0.53 million. See Exhibit I.STAFF.4 for further explanation.
[4] EB-2019-0247, OEB Decision and Order, August 13, 2020, p. 11.

OVERVIEW

1. The purpose of this evidence is to further outline the application ("Application") of Enbridge Gas Inc. ("Enbridge Gas") for: (i) approval to charge customers a Federal Carbon Charge on a volumetric basis, in the amount of the Federal Carbon Charge required to be paid by Enbridge Gas pursuant to the *Greenhouse Gas Pollution Pricing Act* ("GGPPA"), effective April 1, 2022; (ii) approval of just and reasonable rates for all Enbridge Gas rate zones, effective April 1, 2022, to allow Enbridge Gas to recover other costs (including the Facility Carbon Charge costs) incurred in compliance with the GGPPA and the *Greenhouse Gas Emissions Performance Standards Regulation* ("EPS Regulation"); (iii) approval of 2020 balances for all federal carbon pricing program ("FCPP") related deferral and variance accounts, for all Enbridge Gas rate zones, and disposition of the same, effective April 1, 2022; and (iv) an amendment to the wording of the FCPP-related deferral and variance accounting orders recognizing the change from the federal Output-Based Pricing System ("OBPS") to the provincial Emissions Performance Standards ("EPS").

2. Enbridge Gas's Application is being submitted at this time to facilitate compliance with the GGPPA, the EPS Regulation, and to allow customers to be charged the 2022 Federal Carbon Charge rate for natural gas in a timely fashion without accruing uncharged amounts, in accordance with the FCPP, beginning April 1, 2022.

3. This exhibit of evidence is organized as follows:

1. <u>Background</u>

4. On June 21, 2018, the *Budget Implementation Act, 2018, No. 1* received Royal Assent. Part V included the GGPPA. The FCPP applies in whole or in part to any province or territory that requested it or that did not have an equivalent carbon pricing system in place by January 1, 2019. On October 23, 2018, the federal government confirmed that the GGPPA would apply to Ontario.

5. On November 18, 2019, Enbridge Gas filed its 2020 Federal Carbon Pricing Program application (EB-2019-0247) ("2020 Application"). The OEB supported Enbridge Gas's proposal to delay seeking OEB approval to dispose of 2020 balances in FCPP-related deferral and variance accounts by one year (to be filed as part of Enbridge Gas's 2022 Federal Carbon Pricing Program application by September 2021) in order for Enbridge Gas to file final audited year-end 2020 balances in these accounts.[1]

6. As part of its Decision and Order on Enbridge Gas's 2020 Application, the OEB ordered that for First Nations on-reserve customers the Federal Carbon Charge remain interim and that Enbridge Gas track charges for these customers until such time that the OEB makes a determination regarding the constitutional applicability of FCPP-related charges to them ("Deferred Issues"). Further, in its Decision and Rate Order dealing with Enbridge Gas's 2020 Application the OEB ordered that Enbridge Gas include in its rate schedules a reference to the interim nature of the Federal Carbon Charge for these customers. The OEB issued its Decision and

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[1] EB-2019-0247, OEB Decision and Order, August 13, 2020, p. 21.

Order regarding the Deferred Issues on September 23, 2021. The OEB concluded that the FCPP-related charges can be billed and collected on the natural gas bill of Indigenous customers, including First Nations on-reserve customers. The OEB ordered that the FCPP-related rates previously approved on an interim basis for First Nations on-reserve customers are approved on a final basis for these customers.[2] In accordance with this Decision and Order, Enbridge Gas will remove the reference to the interim nature of the Federal Carbon Charge for First Nations on-reserve customers from the rate schedules in its January 1, 2022 Quarterly Rate Adjustment Mechanism ("QRAM") application.

7. On September 21, 2020, the Province of Ontario announced that the federal government accepted Ontario's carbon pricing system for industrial emitters, known as the Ontario EPS program, as an alternative to the federal OBPS. On March 29, 2021, the federal government announced that effective January 1, 2022 the Ontario EPS will replace the federal OBPS. The GGPPA was amended on September 1, 2021 to remove Ontario from Part 2 of Schedule 1 of the GGPPA, enabling the EPS to take effect in Ontario as of January 1, 2022.

8. This evidence also includes cost estimates and volume forecasts for 2022 that are meant to be used for informational purposes only. Customers will be charged the Federal Carbon Charge and Facility Carbon Charge based on actual volumes. Enbridge Gas will seek disposition of any variance to forecast for 2022 as well as FCPP-related 2022 administration costs through a future application to the OEB.

1.1. <u>The Federal Carbon Pricing Program</u>

9. The FCPP is composed of two elements:
   a. A charge on fossil fuels (the "Federal Carbon Charge") as a cost per unit of fuel, including natural gas (cubic meters or m^3), imposed on distributors,

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[2] EB-2019-0247, OEB Decision and Order, September 23, 2021, p.31.

importers and producers applicable from 2019 to 2022 under Part 1 of the GGPPA. This charge applies to fuel delivered by Enbridge Gas to its customers and to Enbridge Gas's own fuel use within its distribution system (i.e. its "Company Use" for distribution buildings, boilers/line heaters and Natural Gas Vehicle ("NGV") fleet fuel). Exemptions from the Federal Carbon Charge are explained below. The Federal Carbon Charge is equivalent to $50 per tonne of carbon dioxide equivalent ("tCO_2e") or 9.79 ¢/m^3 in 2022 (see Table 1). The Federal Carbon Charge became effective April 1, 2019 and increases each subsequent year on April 1.

Table 1
2019 – 2022 Federal Carbon Charge Rates for Marketable Natural Gas[3]

Year	$/$tCO_2e$	¢/m^3
2019	$20	3.91
2020	$30	5.87
2021	$40	7.83
2022	$50	9.79

In December 2020, the federal government released its updated climate plan, "A Healthy Environment and A Healthy Economy", outlining the strategy to reduce greenhouse gas ("GHG") emissions.[4] Included in this plan was a proposal to increase the Federal Carbon Charge by $15/$tCO_2e$ annually starting in 2023, increasing to $170/$tCO_2e$ in 2030. The federal government confirmed this Federal Carbon Charge increase in July 2021.[5] The rates for 2023 to 2030 are shown in Table 2 for informational purposes only, as the GGPPA has not yet been amended to reflect the updated rates.

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[3] The GGPPA, Schedule 2 and Schedule 4. https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf
[4] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/healthy_environment_healthy_economy_plan.pdf
[5] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

Table 2
2023 – 2030 Federal Carbon Charge Rate

Year	$/t CO_2e
2023	$65
2024	$80
2025	$95
2026	$110
2027	$125
2028	$140
2029	$155
2030	$170

b. Entities that are covered under Part 2 of the GGPPA, “Industrial Greenhouse Gas Emissions”, are exempt from coverage under Part 1 of the GGPPA, “Fuel Charge”. Part 2 entities are instead covered under an OBPS, with mandatory and voluntary participation thresholds, established for prescribed industrial facilities that emit specified volumes of GHG emissions, measured in tCO_2e, annually.[6] This component of the GGPPA became effective January 1, 2019.

The OBPS creates a pricing incentive to reduce GHG emissions from Energy Intensive and Trade Exposed (“EITE”) industrial facilities while limiting the impacts of carbon pricing on their respective competitiveness. Entities subject to the OBPS are required to apply to Environment and Climate Change Canada (“ECCC”), and the Canada Revenue Agency (“CRA”) for exemption from the Federal Carbon Charge. The exemption certificate issued by the CRA must then be submitted to Enbridge Gas to ensure that the entity is not charged the Federal Carbon Charge on its natural gas bill.

[6] Under the OBPS, the mandatory emissions threshold for entities identified as being in an Energy Intensive and Trade Exposed sector has been established as 50 ktCO_2e or more per year by Environment and Climate Change Canada. Voluntary participants may opt-in to the OBPS if the entity emits between 10 - 50 ktCO_2e per year. In both cases, facilities must carry out an activity for which an Output-Based Standard is prescribed to be eligible. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html

Participants in the OBPS are required to report and manage their own compliance obligations and have the following options to satisfy annual emissions that exceed their sector-based emission intensity benchmark:[7]

(i) pay the excess emissions charge;[8]

(ii) submit surplus credits issued by the federal government ("Credits");

(iii) submit eligible offset credits ("Offset Credits");[9] or

(iv) submit eligible Recognized Units.[10]

10. The FCPP applies in whole or in part only in provinces or territories that requested it, or that do not have their own carbon pricing systems. In provinces or territories with their own carbon pricing systems that have been approved by the federal government, Part 1 and/or Part 2 of the GGPPA do not apply.

11. Effective January 1, 2022, Ontario is implementing its own carbon pricing system for industrial emitters, called the Ontario EPS program, and will no longer be covered under Part 2 of the GGPPA.[11] The following announcements and changes to legislation have been made regarding the transition to EPS:

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[7] Output Based Standards are included for each industrial activity in Schedule 1 of the Output Based Pricing System Regulations https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/page-15.html#h-1185036

[8] Excess emissions charge is the carbon price in $/tCO_2e$ as outlined in Table 1. Rates of charge applicable from 2019-2022 are outlined in Schedule 4 of the GGPPA.

[9] Offset Credits represent greenhouse gas emissions reductions or removal enhancements generated from Canadian voluntary project-based activities that are not subject to carbon pricing and that would not have occurred under business as usual conditions (i.e. the reductions go beyond legal requirements and standard practice). Details of the proposed federal offset credit program were made available in June 2019 through a discussion paper entitled Carbon Pollution Pricing: Options for a Federal GHG Offset System (https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/federal-offset-system.html) and in July 2020 through a discussion paper entitled Carbon Pollution Pricing: Considerations for Protocol Development in the Federal GHG Offset System (https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/carbon-pollution-pricing-considerations-protocol-development.html). The federal GHG offset regulation is anticipated to be published in the Fall of 2021.

[10] Offset credits generated by federally approved provincial offset protocols. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/list-recognized-offset-programs-protocols.html

[11] https://canadagazette.gc.ca/rp-pr/p2/2021/2021-09-01/html/sor-dors195-eng.html

(i) On September 21, 2020, the province of Ontario announced that the federal government accepted the Ontario EPS program as an alternative to the OBPS.

(ii) On December 23, 2020, the federal government issued a Notice of Intent to amend the OBPS Regulations to reflect the removal of Ontario as a listed province under Part 2 of Schedule 1 of the GGPPA to facilitate the implementation of Ontario's EPS program as an alternative to the OBPS.

(iii) On March 29, 2021, the federal government announced that the federal OBPS will stand down in Ontario at the end of 2021 and Ontario will transition to the EPS effective January 1, 2022.

(iv) On September 1, 2021, the *Order Amending Part 2 of Schedule 1 to the Greenhouse Gas Pollution Pricing Act* was published in the *Canada Gazette,* Part II, which removes Ontario from Part 2 of Schedule 1 of the GGPPA as of January 1, 2022.

12. Similar to the OBPS, the EPS creates a pricing incentive to reduce GHG emissions from EITE industrial facilities while limiting the impacts of carbon pricing on their respective competitiveness. Under the EPS Regulations, the Ontario Ministry of Environment, Conservation and Parks ("MECP") established a mandatory emissions threshold for entities identified as being in an EITE sector (facilities which have a primary activity listed in Schedule 2 of the EPS Regulation) of 50 $ktCO_2e$ or more per year and a voluntary emissions threshold of 10 – 50 $ktCO_2e$ per year for those entities that choose to voluntarily participate in the EPS.

13. Entities that are covered under the EPS are exempt from coverage under Part 1 of the GGPPA. Entities included in the EPS will be required to apply to the MECP, and the CRA for exemption from the Federal Carbon Charge. The Exemption Certificate issued by the CRA must then be submitted to Enbridge Gas to ensure that the entity is not charged the Federal Carbon Charge on its natural gas bill. Entities registered under the OBPS that will be transitioning to the EPS effective

January 1, 2022 will be reissued exemption documentation from the CRA. Enbridge Gas will maintain exemptions for customers who have provided the Company with their reissued Exemption Certificate, unless they otherwise notify Enbridge Gas that they are not eligible for exemption in EPS. Enbridge Gas will also exempt any additional eligible customers who submit an Exemption Certificate in the future. Participants in the EPS will be required to report and manage their own compliance obligations and if their annual emissions are greater than the total annual emissions limit, participants will have the following options to satisfy their compliance obligation:[12]

(i) pay the excess emissions charge;[13] or

(ii) submit emissions performance units issued by the provincial government ("EPUs").

14. Enbridge Gas is working to understand the transition plan from the OBPS to the EPS and reserves its right to amend this Application as appropriate once additional details are announced. Certain aspects of this transition have not yet been finalized by the relevant governmental authorities and may ultimately impact the costs incurred by Enbridge Gas in complying with the GGPPA and EPS. Any cost impacts to the Facility Carbon Charge due to a change in the estimated EPS compliance obligation will be included in the Facility Carbon Charge – Variance Accounts for future disposition.[14] In addition, the deadline for satisfying a participant's compliance obligation for 2021 emissions covered by the OBPS will occur in 2022 after the effective date of the Ontario EPS program.

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[12] MECP: GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit, July 2019, p.17. https://www.ontariocanada.com/registry/showAttachment.do?postingId=28727&attachmentId=41017

[13] Excess emissions charge is the price per unit in \$/tCO_2e. Rates of charge applicable from 2019-2022 are outlined in Section 11(9) of the EPS Regulations. For the 2022 compliance period, the excess emissions charge is \$50/tCO_2e.

[14] An amendment to the wording of the approved FCPP-related deferral and variance accounting orders has been proposed in this application which may result in new acronyms for the FCPP-related deferral and variance accounts. Please refer to Exhibit C and Exhibit C, Attachment 1 for more information.

15. As a result of the transition from OBPS to EPS and in recognition that Enbridge Gas will be subject to both federal and provincial regulations beginning January 1, 2022, Enbridge Gas requests an update to the accounting orders to reflect this change. Enbridge Gas's proposed update to the accounting orders can be found at Exhibit C, Attachment 1.

16. Any natural gas volumes delivered by Enbridge Gas for the period of January 1, 2022 to March 31, 2022 will continue to be charged the Federal Carbon Charge and Facility Carbon Charge rates approved by the OEB as part of Enbridge Gas's 2021 Application. With the transition from the OBPS to the EPS, any variance between what is recovered in rates and Enbridge Gas's actual compliance obligations will be captured in the OEB-approved variance accounts to be disposed of through a future FCPP application.

17. The only aspect of the FCPP that currently remains under development is the Federal GHG offset system regulations and offset protocols, which are anticipated to be completed fall of 2021. The EPS currently has no provision for use of offsets, although this may change in the future.

2. <u>Enbridge Gas's Obligations Under the GGPPA and EPS Regulation</u>

18. As a natural gas utility in Ontario, a "listed province" in the GGPPA, Enbridge Gas is required to register under Part 1 of the GGPPA with the CRA as a "distributor" for volumes of natural gas delivered to its customers.[15]

19. As a "distributor", Enbridge Gas is required to remit Federal Carbon Charges related to the GGPPA to the Government of Canada.

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[15] The GGPPA, s.55 (1). The GGPPA requires registration of distributors of marketable or non-marketable natural gas. https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

20. Enbridge Gas is also required to register under the EPS Regulation as a "covered facility" since its transmission and storage operations are covered by an industrial activity listed in Schedule 2 of the EPS Regulation.[16]

21. As a "covered facility" under the EPS Regulation, Enbridge Gas is required to remit payment for any excess emissions under the EPS.

22. Enbridge Gas has estimated its 2022 cost of compliance with the GGPPA and EPS Regulation to be approximately $1.68 billion: $1,039.50 million for the EGD rate zone (see Exhibit B, Tab 1 for additional detail) and $644.36 million for the Union rate zones (see Exhibit B, Tab 2 for additional detail). In addition, Enbridge Gas estimates that it will incur 2022 administrative costs of approximately $5.21million /c
associated with the administration of its requirements under the GGPPA and EPS Regulation (see Exhibit C for additional detail).

2.1 Volumes Subject to Federal Carbon Charge

23. Except for customer volumes that are covered under the EPS, or those that are otherwise fully or partially exempt from the Federal Carbon Charge, all distribution volumes delivered by Enbridge Gas in Ontario ("Customer Volumes") are covered under Part 1 of the GGPPA and are subject to the Federal Carbon Charge.[17]

24. Under the GGPPA Enbridge Gas is required, on a monthly basis, to:[18]
    - calculate and report to the CRA the volume of fuel consumed which is covered under Part 1 of the GGPPA, including Enbridge Gas's own use

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[16] The EPS, O.Reg. 241/19. https://www.ontario.ca/laws/regulation/r19241
[17] To calculate Enbridge Gas's 2022 customer volume forecast at Exhibit B, Tab 1, Schedule 1, and at Exhibit B, Tab 2, Schedule 1, Enbridge Gas excluded customers who have provided Enbridge Gas with an exemption certificate, in accordance with Section 17(2) of the GGPPA. This includes downstream distributors, entities covered under the EPS program, and customers who use natural gas in a non-covered activity. RNG volumes and 80% of volumes for eligible greenhouses are also excluded.
[18] The GGPPA, s.68 (2b), s.71 (3). https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

within its distribution system (i.e. distribution buildings, boilers/line heaters and NGV fleet volumes); and

- remit the amount of the Federal Carbon Charge in respect of the monthly volume that has been calculated.

Forecast Customer Volumes and Costs

25. As set out in Table 1, Enbridge Gas is required to remit the 2022 Federal Carbon Charge rate of 9.79 ¢/m^3 of natural gas consumed for applicable customers from April 1, 2022 to March 31, 2023. As outlined at Exhibit D and consistent with Enbridge Gas's treatment of 2019, 2020 and 2021 FCPP-related charges, Enbridge Gas will present these charges as a separate line item on customers' bills. Enbridge Gas's forecast cost associated with Customer Volumes for the period of April 1, 2022 to March 31, 2023 is $1,677.33 million: $1,038.41 million for the EGD rate zone and $638.92 million for the Union rate zones (please see Exhibit B for additional detail on costs associated with Customer Volumes for the period of April 1, 2022 to March 31, 2023).

26. These cost estimates are subject to change based on actual distribution volumes and are meant to be used for informational purposes only. Customers will be charged the Federal Carbon Charge rate monthly based on actual billed volumes.

27. Customers that hold an Exemption Certificate must provide a copy to Enbridge Gas no later than two weeks in advance of the first day of the month in which they wish to have their consumption volumes exempted from the Federal Carbon Charge. Similarly, if a customer is no longer eligible to hold an Exemption Certificate, they must provide notice to Enbridge Gas to remove the exemption from the Federal Carbon Charge.

Forecast Company Use Volumes and Costs

28. As set out in Table 1, Enbridge Gas is required to remit the 2022 Federal Carbon Charge rate of 9.79 ¢/m^3 for natural gas consumed in the operation of Enbridge Gas's facilities which are not covered by the EPS (i.e. distribution buildings, boilers/line heaters and NGV fleet volumes) ("Company Use Volumes"). The costs associated with Company Use Volumes will be recovered from customers as part of the Facility Carbon Charge, as detailed at Exhibit D, included in delivery or transportation charges on customers' bills. Enbridge Gas's forecast cost associated with Company Use Volumes for the period of April 1, 2022 to March 31, 2023 is approximately $2.72 million: $0.58 million for the EGD rate zone and $2.14 million for the Union rate zones (please see Exhibit B for additional detail on costs associated with Company Use Volumes for the period of April 1, 2022 to March 31, 2023).

29. The forecast Company Use Volumes and associated Facility Carbon Charge cost estimate are subject to change based on actual Facility Volumes.

2.2 Volumes Subject to EPS

30. Transmitting natural gas is a covered "industrial activity" under the EPS and includes installations and equipment such as compressor stations, storage installations, and compressor units that have a common owner/operator within a province.[19] For Enbridge Gas, this includes fuel used in transmission and storage compressor facilities ("EPS Volumes").

31. Under the EPS, Enbridge Gas is required, on an annual basis, to:
    - calculate and report to the Ontario MECP Enbridge Gas's covered emissions and total annual emissions limit for each compliance period; and

[19] The EPS, O.Reg. 241/19. https://www.ontario.ca/laws/regulation/r19241

- provide compensation for, or otherwise obtain EPUs, to cover any excess emissions by the applicable deadline.

32. EPS-covered facilities have a compliance obligation for the portion of their emissions that exceed their total annual emissions limit. Under the EPS, a covered facility's total annual emissions limit is calculated based on the applicable Performance Standard ("PS") and its associated annual production.[20] The PS for facilities transmitting natural gas is 80% of the production-weighted facility baseline emissions intensity.[21] The costs associated with EPS Volumes will be recovered from customers as part of the Facility Carbon Charge, as detailed at Exhibit D, included in delivery or transportation charges on customers' bills. Enbridge Gas's forecast 2022 (January 1, 2022 to December 31, 2022) cost associated with EPS Volumes is $3.81 million: $0.50 million for the EGD rate zone and $3.31 million for the Union rate zones (please see Exhibit B for additional detail on costs associated with EPS Volumes for the period of January 1, 2022 to December 31, 2022).

2.3 Management of Facility-Related Emissions and Costs

33. Consistent with Enbridge Gas's commitment in the 2021 Application "…to identify, track and report on emission reduction opportunities using criteria that effectively balance management of its compliance obligations under the FCPP, estimated capital costs, safety and operational reliability,"[22] this section of evidence contains details on the potential options for reducing Enbridge Gas's facility-related emissions and associated costs.[23] Facility-related emissions and associated costs can be reduced through the reduction of either Company Use Volumes or

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[20] MECP: GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit, July 2019, Section 3. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html
[21] The EPS, O.Reg. 241/19, Table 4.2. https://www.ontario.ca/laws/regulation/r19241
[22] EB-2020-0212, Enbridge Gas FCPP Application, September 30, 2020, Exhibit A, para. 28, p 14.
[23] EB-2019-0247, Enbridge Gas Reply Argument, July 16, 2020, p.13. The OEB subsequently found that Enbridge Gas's proposal was appropriate; EB-2019-0247, OEB Decision and Order, August 13, 2020, pp. 9-10.

OBPS/EPS Volumes, or, in the case of OBPS/EPS emissions, through the use of lower cost compliance options.

Facility-Related Volume Reductions

34. In 2019, Enbridge Inc. (the parent company of Enbridge Gas) implemented a Carbon and Energy Efficiency Plan ("CEE Plan") to identify emission reduction opportunities in each of its business units, including at Enbridge Gas. At that time, Enbridge Gas stated that it had not yet identified cost-effective opportunities that would result in significant reductions in emissions related to stationary combustion and flaring.[24]

35. In November 2020, Enbridge Inc. announced expanded environmental, social and governance ("ESG") targets related to reducing GHG emissions from operations. This includes achieving net zero emissions by 2050 and a 35% reduction in GHG emission intensity by 2030.

36. In 2021, Enbridge Gas initiated the Facility GHG Emissions Reduction project. The Facility GHG Emissions Reduction project continues the work that Enbridge Gas has completed in previous years as part of the CEE Plan, by identifying and reviewing potential GHG emission reduction opportunities and strategies to support the ESG targets, and evaluating the feasibility, emission reduction potential and cost of opportunities identified.

37. As discussed in Enbridge Gas' 2021 Application there were four opportunities identified with the potential to reduce OBPS/EPS-volumes.[25] Table 3 below shows an overview of the four opportunities identified to date.

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[24] Cost-effectiveness on a $/t$CO_2$e basis is based on a comparison to the excess emission charge, which is the carbon price in $/t$CO_2$e as outlined in Exhibit A, Table 1. Rates of charge applicable from 2019-2022 are outlined in Schedule 4 of the GGPPA. [25] EB-2020-0212, Enbridge Gas FCPP Application, September 30, 2020, Exhibit A, Table A-2, p. 12.
[25] EB-2020-0212, Enbridge Gas FCPP Application, September 30, 2020, Exhibit A, Table A-2, p. 12.

Table 3
Facility-Related Emission Reduction Project Summary

	Opportunity	**Total Estimated Capital Cost** ($millions)	**Estimated Emissions Reductions – 2020** (tCO_2e)	**Forecasted Emissions Reductions – 2022** (tCO_2e)	**Forecasted Emissions Reductions – 10-yr Cumulative** (tCO_2e)	**Cost per Tonne of GHG Emissions** ($\$/tCO_2e$)[26]
1	Online Monitoring	0.05	218	N/A[27]	1,100	-32
2	Air Filters	0[28]	0[29]	184	1,500	-47[30]
3	Plant J Twinning (Electric Drive)	70.00	N/A[31]	N/A	N/A	105
4	Re-wheeling Turbines	17.19	N/A[32]	N/A	N/A	191

38. Two of the opportunities, Online Monitoring and Air Filters, have been implemented while the Plant J Twinning and Re-wheeling Turbines will not be moving forward as

[26] A Discounted Cash Flow analysis was conducted to calculate the $\$/tCO_2e$ cost (represented by a positive $\$/tCO_2e$ figure) or savings (represented by a negative $\$/tCO_2e$ figure) of CEE plan opportunities. Cash outflows include incremental capital costs of each opportunity. Cash inflows include resulting natural gas savings, avoided carbon charges, any other incremental O&M costs or savings, income tax impacts and any operating costs or savings resulting from the opportunity. The net present value ("NPV") of cash inflows and outflows is divided by total expected emissions avoided to determine the $\$/tCO_2e$.

[27] Implementation of online monitoring on applicable units is expected to be completed by the end of 2021. The total 10-yr cumulative emissions reductions of 1,100 tCO2e are expected to be reduced in full once this is complete in 2021.

[28] Initial O&M costs for the air filter replacement program are estimated to be $10,000 in 2021 but once the program is fully implemented, it is estimated that there will be an O&M savings of approximately $150,000/year.

[29] Although the program was implemented in 2020, due to the condition of existing filters, no upgrades were made in 2020. The implementation of the program will result in the higher efficiency filters will be installed at the next filter change opportunity.

[30] Although the forecasted emissions reductions have decreased upon review of this opportunity, the economic analysis was not updated, as this opportunity is moving forward as part of the implementation of a more effective maintenance strategy.

[31] This opportunity is currently not being implemented as it is not cost-effective, and therefore no emission reductions will occur in 2022.

[32] This opportunity is currently not being implemented as it is not cost effective, and therefore no emission reductions will occur in 2022.

they are currently not feasible due to their high costs per tonne compared to the excess emissions charge.

39. As part of the Facility GHG Emissions Reduction project, Enbridge Gas will continue to identify and review opportunities that reduce stationary combustion emissions (OBPS/EPS emissions) through various pathways, including electrification and RNG fuel switching. In addition to the opportunities identified above, Enbridge Gas is currently developing a plan for compressor unit lifecycle replacement. As part of this long-term plan to replace identified compression, several factors are being considered in the evaluation of alternatives, including meeting the operating requirements for the storage and transmission systems, reliability, environmental compliance, and carbon reduction strategy. There are currently no OBPS/EPS emissions impacts anticipated for 2022, however, emission reduction opportunities and the cost of carbon are being considered in the development of this strategy. As part of this Facility GHG Emissions Reduction project, identified opportunities will be reviewed on an annual basis, including revisiting any previous assumptions, project costs and the cost of carbon.

40. Additional emission reductions are anticipated as part of regular asset management work and equipment life-cycle replacement. For example, Enbridge Gas's Asset Management Plan includes replacement of heating equipment which is installed to prevent equipment from freezing as well as to prevent or reduce the amount of frost heave experienced at a station. It is expected that the regular upgrade of heaters within the system will result in additional emission reductions of 1,700 tCO_2e by 2030, reducing emissions covered under the Federal Carbon Charge. This project has not been listed in the table above because it is considered a maintenance activity with the primary driver for the work being asset condition and has not been included as a project under the CEE Plan.

41. Going forward, Enbridge Gas will continue to identify, track and report on emission reduction opportunities using criteria that effectively balance management of its compliance obligations under the FCPP, estimated capital costs, safety and operational reliability. Enbridge Gas will include details of cost-effective emission reduction opportunities, as appropriate, in future FCPP applications. Actual GHG emission and reductions in OBPS/EPS costs resulting from these opportunities will be reflected in Enbridge Gas's future FCPP applications for clearance of FCPP-related deferral and variance accounts.

OBPS and EPS Compliance Cost Reductions

42. Enbridge Gas has alternative compliance options to satisfy its annual OBPS and EPS compliance obligation aside from paying the excess emissions charge, including the purchase of Credits or EPUs from other OBPS or EPS participants, respectively, and in the OBPS purchasing Offset Credits.

43. For Enbridge Gas to satisfy its 2020 OBPS compliance obligation, paying the excess emissions charge was the only viable option due to several factors including:

    i) The delayed timing of Credit issuance. Due to the COVID-19 pandemic, ECCC announced in April 2020 that the reporting and compensation deadlines for the 2019 compliance period would be delayed. The reporting deadline was moved from June 1, 2020 to October 1, 2020. The regular-rate compensation deadline was moved from December 15, 2020 to April 15, 2021. This delayed the allocation of Credits until the first quarter of 2021. These Credits were then expected to trade on the market at a price slightly below the 2021 excess emissions charge of \$40/tCO_2e which would have cost more than paying the 2020 excess emissions charge of \$30/tCO_2e.

ii) The delayed implementation of the federal offset program, which was in development in 2020, and is not anticipated to be finalized until later in 2021 at the earliest.

iii) Short timelines to purchase and retire Offset Credits from other provinces, referred to as “Recognized Units”. On August 25, 2020, ECCC announced that facilities with a compliance obligation under OBPS could procure Offset Credits from Alberta. With market prices of Offset Credits in Alberta expected to increase in the fourth quarter of 2020, Enbridge Gas did not have enough time to take the required steps to procure Offset Credits from Alberta below the 2020 excess emissions charge of $30/tCO_2e.

44. For Enbridge Gas’s 2022 EPS compliance obligation, the availability and market attributes of EPUs will be reviewed to determine if they present a viable means of reducing compliance costs.[33] If Enbridge Gas procures EPUs at a lower price than the excess emissions charge, the difference between these two costs will be recorded in the Facility Carbon Charge –Variance Accounts[34] and Enbridge Gas will seek to dispose of those amounts through a future FCPP application.[35]

45. Additional administrative costs may be incurred, such as increased staffing, and legal and consulting costs, in order to pursue and acquire EPUs and/or Offset Credits. All actual administrative costs incurred will be recorded in the Greenhouse Gas Emissions Administration Deferral Accounts and Enbridge Gas will seek to dispose of those amounts through a future FCPP application.

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[33] Currently, the EPS Regulation does not allow the use of Offset Credits as a viable compliance option.
[34] An amendment to the wording of the approved FCPP-related deferral and variance accounting orders has been proposed in this application which may result in new acronyms for the FCPP-related deferral and variance accounts. Please refer to Exhibit C and Exhibit C, Attachment 1 for more information.
[35] EB-2019-0247, Exhibit I.STAFF.8 b) and c), June 18, 2020; EB-2019-0247, Enbridge Gas Reply Argument, July 16, 2020, p. 12.

3. Bill Impacts

46. The bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,400 m3 is an increase of $47.05 per year in the EGD rate zone. The bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,200 m3 is an increase of $43.14 per year in the Union rate zones.

47. The bill impact of the proposed 2020 FCPP-related deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,400 m^3 is $0.72 in the EGD rate zone. The bill impact of the proposed 2020 /c FCPP-related deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,200 m^3 is $0.27 in the Union South rate zone and $0.34 in the Union North rate zone.

4. Requested Approvals

48. As the costs to comply with the GGPPA and EPS Regulation in 2022 form part of Enbridge Gas's ongoing operating costs as a utility, and consistent with Enbridge Gas's 2021 Application, Enbridge Gas proposes to continue to treat all prudently incurred costs of compliance with the GGPPA and EPS Regulation as a pass-through to customers (Y Factor).

49. Through this Application and by February 10, 2022, Enbridge Gas is seeking:
    a. OEB approval of rates to be applied to customer bills beginning April 1, 2022. Following the issuance of the OEB's Decision and Order for this Application, Enbridge Gas intends to reflect 2022 rate increases associated with the Federal Carbon Charge and Facility Carbon Charge in its April 1, 2022 QRAM application.
    b. OEB approval to dispose of the 2020 balances recorded in Enbridge Gas's FCPP-related deferral and variance accounts effective April 1, 2022. Following the issuance of the OEB's Decision and Order for this

Application, Enbridge Gas intends to dispose of these balances as a one-time adjustment in the April 1, 2022 QRAM.

c. Approval to amend the wording of the FCPP-related deferral and variance accounting orders to recognize the change from the federal OBPS to the provincial EPS.

DEFERRAL AND VARIANCE ACCOUNTS

1. The purpose of this exhibit of evidence is to address deferral and variance account matters associated with Enbridge Gas's Application. As outlined in the Application, Enbridge Gas is seeking disposition of 2020 balances in FCPP-related deferral and variance accounts for each of the EGD rate zone and Union rate zones, and an amendment to the wording of the FCPP-related deferral and variance accounting orders recognizing the change from the federal OBPS to the provincial EPS. Allocation and disposition of 2020 deferral and variance account balances is discussed in detail at Exhibit D.

2. This exhibit of evidence is organized as follows:
    1. Established FCPP-Related Deferral and Variance Accounts
    2. Accounting Order Amendments
    3. 2020 FCPP-Related Deferral and Variance Account Balances
        - 3.1. 2020 Administration Costs Recorded in the GGEADA
        - 3.2. 2020 Customer-Related Costs Recorded in the FCCCVA
        - 3.3. 2020 Facility-Related Costs Recorded in the FCCFVA
    4. Forecast 2022 Administration Costs (for informational purposes only)

1. Established FCPP-Related Deferral and Variance Accounts

3. In its 2019 Application, to facilitate compliance with the GGPPA in 2019 and beyond and ensure that the costs of compliance with the GGPPA were clearly delineated from those incurred under the Cap-and-Trade Program, Enbridge Gas requested OEB approval to establish five new deferral and variance accounts. The new accounts would record: (i) actual combined administration costs for all rate zones (effective January 1, 2019); (ii) Federal Carbon Charge cost variances between the actual costs incurred and the amount collected through rates related to the volumes delivered by Enbridge Gas for each of the EGD rate zone and Union rate zones (effective April 1, 2019); and (iii) Facility Carbon Charge cost variances between the actual costs incurred and the amount collected through

rates related to Company Use and OBPS volumes associated with Enbridge Gas's own operations for each of the EGD rate zone and the Union rate zones (effective January 1, 2019).[1]

4. In its Decision and Order on Enbridge Gas's 2019 Application, the OEB approved the establishment of Enbridge Gas's requested new FCPP-related deferral and variance accounts with a single exception; rather than approving a single deferral account to record the combined administration costs for all rate zones, the OEB directed that Enbridge Gas should establish two GGEADA, one for each of the EGD rate zone and the Union rate zones.[2]

5. Accordingly, Enbridge Gas established the following FCPP-related deferral and variance accounts:

    1. GGEADA – EGD Rate Zone;[3]
    2. GGEADA – Union Rate Zones;[4]
    3. FCCCVA – EGD Rate Zone;[5]
    4. FCCCVA – Union Rate Zones;[6]
    5. FCCFVA – EGD Rate Zone;[7] and
    6. FCCFVA – Union Rate Zones.[8]

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[1] EB-2018-0205, EGI 2019 FCPP Application, October 10, 2018, Exhibit D, Tab 1, Schedule 1, pp. 2-4.
[2] EB-2018-0205, OEB Decision and Order, July 4, 2019, pp. 9-10.
[3] EGD Rate Zone Account No. 179-501, to record the administration costs associated with the impacts of federal regulations related to greenhouse gas emission requirements for Enbridge Gas within the EGD rate zone effective January 1, 2019.
[4] Union Rate Zones Account No. 179-422, to record the administration costs associated with the impacts of federal regulations related to greenhouse gas emission requirements for Enbridge Gas within the Union rate zones effective January 1, 2019.
[5] EGD Rate Zone Account No. 179-502, to record the variances between actual customer carbon costs and customer carbon costs recovered in rates for distribution volumes delivered by Enbridge Gas within the EGD rate zone effective April 1, 2019. Except for exempted customers as explained in Exhibit A.
[6] Union Rate Zones Account No. 179-421, to record the variances between actual customer carbon costs and customer carbon costs recovered in rates for distribution volumes delivered by Enbridge Gas within the Union rate zones effective April 1, 2019. Except for exempted customers as explained in Exhibit A.
[7] EGD Rate Zone Account No. 179-503, to record the variance between actual facility carbon costs and facility carbon costs recovered in rates within the EGD rate zone effective January 1, 2019.
[8] Union Rate Zones Account No. 179-420, to record the variance between actual facility carbon costs and facility carbon costs recovered in rates within the Union rate zones effective January 1, 2019.

2. Accounting Order Amendments

6. As a result of the transition from the federal OBPS to the provincial EPS and in recognition that Enbridge Gas will be subject to both federal and provincial regulations beginning January 1, 2022, Enbridge Gas is proposing to update the accounting orders to reflect this change, effective January 1, 2022.

7. Enbridge Gas is requesting to update the applicable account definitions to include reference to both federal and provincial regulations and to update the applicable account names to remove the word "Federal". Enbridge Gas's requested update to the accounting orders can be found attached to this exhibit, Exhibit C. Attachment 1 shows the changes to the accounting order in black-line revision marking, and Attachment 2 is a clean version of the proposed changes.

3. 2020 FCPP-Related Deferral and Variance Account Balances

8. Enbridge Gas is seeking to dispose of: 2020 administration costs of $2.44 million in /c
the GGEADAs and 2020 facility-related costs of $(0.80) million in the FCCFVAs. The 2020 FCCCVAs have a zero balance.

3.1 2020 Administration Costs Recorded in the GGEADA

9. As set out in Table 1, Enbridge Gas's 2020 administration costs are
$2.44 million. A description of variances to Enbridge Gas's forecast 2020 /c
administration costs follows

Table 1
2020 Administration Costs ($millions)

Cost Element	2020 Forecasted Costs[9]	2020 Actual Costs[10]			Variance	
		EGD Rate Zone	Union Rate Zones	Total		
IT Billing System	0.40	0.17	0.14	0.31	(0.09)	
Staffing Resources	0.80	0.52	0.32	0.84	0.04	
Consulting and External Legal Support	0.20	0.08	0.05	0.13	(0.07)	
GHG Reporting and Verification	0.10	0.04	0.02	0.06	(0.04)	
Bad Debt	1.84	0.74	0.29	1.03	(0.81)	/c
Other Miscellaneous Costs	0.20	0.02	0.01	0.04	(0.16)	
Interest[11]	N/A	0.01	0.01	0.02	0.02	/c
Total	**3.54**	**1.59**	**0.85**	**2.44**	**(1.10)**	/c

10. Shared administration costs set out in Table 1, including costs related to: staffing resources, consulting and external legal support, GHG reporting and verification and other miscellaneous costs, have been allocated to the EGD rate zone and Union rate zones in proportion to actual customers' consumption volumes subject to the Federal Carbon Charge from January 1, 2020 to December 31, 2020.[12] Unique administration costs set out in Table 1 that are immediately attributable to a particular rate zone, including costs related to IT billing systems and bad debt, have been allocated to that respective rate zone accordingly. Each of the cost categories set out in Table 1 is further discussed below.

IT Billing System Costs

11. In its 2020 Application, Enbridge Gas forecast costs of $0.40 million related to the IT billing systems, which included $0.20 million for the EGD rate zone and

[9] EB-2019-0247, EGI FCPP Application, May 14, 2020, Updated Exhibit C, Table C-3, p. 14.
[10] Composed of actual 2020 costs from January to December 2020.
[11] Enbridge Gas did not include a 2020 forecast cost for interest.
[12] Approximately 62% of customer consumption volumes were attributable to the EGD rate zone and 38% of customer consumption volumes were attributable to the Union rate zones.

$0.20 million for the Union rate zones.[13] Included in these forecasts was the revenue requirement associated with the Cap and Trade-related billing system functionality, which was re-purposed for GGPPA-related charges. This also included a forecast capital cost of $0.10 million required for additional billing system modifications for the Union rate zones to comply with the GGPPA.

12. The actual revenue requirement impacts for 2020 associated with the re-purposing of the Cap and Trade-related billing system to collect GGPPA-related charges was a deficiency of $0.32 million; partially offset by a $0.01 million sufficiency associated with the first-year revenue requirement for the additional billing system modifications required for the Union rate zones.

Staffing Resources

13. In its 2020 Application, Enbridge Gas forecast costs of $0.80 million for salaries and wages in 2020, which included costs for four full time equivalents ("FTEs") that comprised the Carbon Strategy team.[14]

14. Actual salaries and wages costs incurred in 2020 were $0.84 million. FTE requirements increased from four to five in May 2020, reflecting resource requirements to facilitate compliance with the GGPPA and the incremental effort required for regulations related to GHG emissions requirements including the federal Offset Regulation and the Clean Fuel Regulation.

Consulting and External Legal Support

15. In its 2020 Application, Enbridge Gas forecast consulting and external legal support costs of $0.20 million for 2020.[15] Actual consulting and external legal support costs incurred in 2020 were $0.13 million. Consulting and external legal support costs were lower than forecast due to Enbridge Gas leveraging existing

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[13] EB-2019-0247, EGI FCPP Application, May 14, 2020 Updated Exhibit C, p. 14-15.
[14] Ibid, p. 15.
[15] EB-2019-0247, EGI FCPP Application, May 14, 2020, Updated Exhibit C, p. 16.

internal resources and the delay in the issuance of offset regulations and protocols that may have required additional support.

GHG Reporting and Verification

16. In its 2020 Application, Enbridge Gas forecast costs of $0.10 million for GHG reporting and verification in 2020.[16] Actual GHG reporting and verification costs incurred in 2020 were $0.06 million, including $0.01 million for the pre-verification of Enbridge Gas's 2019 OBPS report and $0.05 million related to the verification of its 2019 OBPS report by a third-party auditor as required under the OBPS Regulations.

Bad Debt

17. In its 2020 Application, Enbridge Gas forecast costs of $1.84 million for bad debt in 2020.[17] Actual bad debt costs incurred in 2020 were approximately $1.03 million. /c

18. The historic methodology used to collect bad debt within the Union rate zones is a contributing factor to the forecast variance. There is a time lag of approximately nine months between billing a customer and the write-off of a corresponding amount as a bad debt. Due to the timing of OEB approval of the 2019 Application, Enbridge Gas did not begin collecting FCPP-related charges from customers until August 1, 2019. As a result of this and the aforementioned nine-month time lag, bad debt for the Union rate zones did not start accumulating until April 1, 2020, therefore reducing the actual 2020 bad debt costs.

19. Consistent with the OEB's Decision and Order on Enbridge Gas's 2020 Application, the $1.03 million is exclusive of COVID-19 impacts. Enbridge Gas has /c recorded bad debt expenses for the FCPP related to the COVID-19 emergency in the COVID-specific sub-account.[18]

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[16] EB-2019-0247, EGI FCPP Application, May 14, 2020, Updated Exhibit C, pp.16-17.
[17] Ibid, p. 17.
[18] EB-2019-0247, OEB Decision and Order, August 13, 2020, p. 11.

Other Miscellaneous Costs

20. In its 2020 Application, Enbridge Gas forecast 2020 other miscellaneous costs of $0.20 million associated with customer outreach and communications, training, conferences, travel expenses, memberships and subscriptions associated with the GGPPA or other federal GHG or carbon pricing programs.[19] Actual other miscellaneous costs incurred in 2020 were $0.04 million. Due to the COVID-19 emergency, costs related to activities such as travel and conferences were limited, therefore reducing actual miscellaneous costs. Enbridge Gas also leveraged existing customer communication pathways, such as QRAM bill inserts, mass emails, webpages, and social media to communicate to customers regarding the FCPP, thus reducing actual 2020 costs related to customer communications.

3.2 2020 Customer-Related Costs Recorded in the FCCCVA

21. Enbridge Gas tracks the difference between the Federal Carbon Charge amount collected through rates and the actual costs incurred in the FCCCVA for each of the EGD rate zone and the Union rate zones. Since Enbridge Gas remits the Federal Carbon Charge to the CRA based on actual billed volumes and the Federal Carbon Charge rate, consistent with the GGPPA, was being collected through rates, there is no FCCCVA balance for either the EGD or Union rate zones.

3.3 2020 Facility-Related Costs Recorded in the FCCFVA

22. As set out in Exhibit A, Enbridge Gas's facility-related volumes and associated costs are composed of Company Use Volumes (facilities which are not covered under the OBPS) and OBPS Volumes from January 1, 2020 to December 31, 2020. Enbridge Gas's 2020 facility-related obligation was $3.15 million ($0.82 million related to Company Use Volumes and $2.33 million related to OBPS

[19] EB-2019-0247, EGI FCPP Application, May 14, 2020, Updated Exhibit C, pp. 17-18.

Volumes), of which $2.91 million is attributable to Enbridge Gas's regulated utility operations.

23. Enbridge Gas has recorded a 2020 facility-related variance of $(0.80) million in the FCCFVA, including $(0.04) million for the EGD rate zone and $(0.76) million for the Union rate zones.[20] This reflects a variance between the actual and forecast facility-related costs, and a variance in the amount of revenue billed through the Facility Carbon Charge, due to a difference in Customer Volumes realized. Table 2 below shows the variance related to the difference between 2020 forecast regulated facility-related volumes, as filed in Enbridge Gas's 2020 Application, and actual regulated facility-related volumes for 2020.

Table 2[21]
2020 Regulated Facility-Related Volumes/Emissions and Costs

	2020 Forecasted Volumes & Emissions	**2020 Forecasted Costs** ($millions)	**2020 Actual Volumes & Emissions**	**2020 Actual Costs** ($millions)	**Variance** ($millions)
Company Use	16,967 10^3m^3	0.83	16,496 10^3m^3	0.82	(0.01)
OBPS	108,162 tCO_2	3.24	69,873 tCO_2	2.10	(1.14)
Total	-	4.07	-	2.91	(1.15)

[20] This variance reflects consideration of: (i) applying the Federal Carbon Charge Rate for Marketable Natural Gas of 3.91 ¢/m^3 from January 1, 2020 – March 31, 2020 and 5.87 ¢/m^3 from April 1, 2020 to December 31, 2020 set out in Exhibit A, Table 1 to actual Company Use Volumes of natural gas consumed in the operation of Enbridge Gas's facilities from January 1, 2020 to December 31, 2020; (ii) Enbridge Gas's 2020 OBPS obligation of $2.10 million related to regulated utility operations for the January 1, 2020 to December 31, 2020 period; (iii) actual billed amounts for the January 1, 2020 to December 31, 2020 period; and (iv) interest of approximately $(0.30) million.

[21] Only volumes/emissions and associated costs related to regulated utility operations are included.

4. Forecast 2022 Administration Costs

24. As set out in Table 3, Enbridge Gas's forecast 2022 administration costs are $5.21 million: $3.51 million for the EGD rate zone and $1.71 million for the Union rate zones. Enbridge Gas will record actual 2022 costs in the GGEADAs until such time that these costs are incorporated into rates. Enbridge Gas is providing forecast 2022 administration costs for informational purposes only and will seek recovery of its actual 2022 administration costs in a future proceeding. /c

Table 3
Forecast 2022 Administration Costs

	2022 Forecast Costs ($millions)			
Cost Element	**EGD Rate Zone**	**Union Rate Zones**	**Total**	
IT Billing System	0.00	0.06	0.06	
Staffing Resources	0.58	0.36	0.94	/c
Consulting & External Legal Support	0.19	0.11	0.30	
GHG Reporting & Verification	0.03	0.02	0.05	
Bad Debt	2.61	1.10	3.72	/c
Other Miscellaneous Costs	0.09	0.06	0.15	
Total	**3.51**	**1.71**	**5.21**	/c

25. Shared administration costs set out in Table 3, including costs related to: staffing resources, consulting and external legal support, GHG reporting and verification and other miscellaneous costs, have been allocated to the EGD rate zone and Union rate zones in proportion to forecast customer consumption volumes subject to the Federal Carbon Charge from January 1, 2022 to December 31, 2022.[22] Unique administration costs set out in Table 3 that are directly attributable to a particular rate zone, including costs related to: IT billing systems and bad debt, have been allocated to that respective rate zone accordingly.

[22] Approximately 62% of forecast customer consumption volumes are attributable to the EGD rate zone and 38% of forecast customer consumption volumes are attributable to the Union rate zones.

26. Enbridge Gas's current OEB-approved 2021 rates and proposed 2022 rates for the EGD rate zone and Union rate zones do not include any FCPP-related administration costs as these costs are considered to be incremental to Enbridge Gas's traditional operations as a regulated natural gas utility in Ontario. A description of the components of Enbridge Gas's forecast 2022 administration costs follows.

IT Billing System Costs

27. For 2022, Enbridge Gas forecasts the IT billing system costs to be $0.06 million. The revenue requirement of $0.06 million is associated with the additional billing system modifications required in 2020 for the Union rate zones.[23] The 2022 revenue requirement for these costs has not been previously collected from customers.

Staffing Resources

28. For 2022, staffing costs are currently estimated to be approximately $0.94 million. /c
These fully allocated costs are for the five FTEs that comprise the Carbon Strategy team in 2020 plus one additional half FTE. This level of staffing reflects the incremental level of effort Enbridge Gas has experienced to date and expects to require across the organization to facilitate compliance with the GGPPA and EPS Regulation in 2022, including the incremental effort to evaluate and procure EPUs. With the establishment of other carbon emission-related programs and initiatives in the future, Enbridge Gas may require incremental staffing resources. Enbridge Gas will seek OEB approval to recover actual 2022 staffing costs required to facilitate compliance with the GGPPA, EPS Regulation and other GHG or carbon pricing regulations, together with its overall 2022 administration costs, in a future proceeding

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[23] As set out in Enbridge Gas's 2020 Application (EB-2019-0247), May 14, 2020, Updated Exhibit C, p. 7, included in the calculation of 2021 revenue requirement for the Union rate zones are capital costs related to additional billing system modifications previously expected to be incurred in 2019 and actually incurred in 2020.

29. The GGPPA and EPS Regulation impacts a wide variety of groups across the organization and wherever reasonable to do so Enbridge Gas has leveraged existing resources outside of the Carbon Strategy team and will continue to do so going forward. This approach is consistent with Enbridge Gas's commitment to cost-effectiveness, productivity gains and continuous improvement. These ancillary resources and related costs will not be recorded in the GGEADA in 2022.

Consulting and External Legal Support

30. Enbridge Gas anticipates that it will incur $0.30 million in consulting and external legal costs in 2022 for work supporting the development and sustainment of Enbridge Gas's carbon strategy and related analyses, the review and interpretation of any new or updated regulations associated with the GGPPA, EPS Regulation, or other GHG or carbon pricing programs, and the development of Enbridge Gas's Application and associated OEB proceedings.

31. These expenditures are required to ensure that Enbridge Gas remains well-informed of, and in compliance with, current and new regulatory requirements. Enbridge Gas also notes that it may incur additional consulting and external legal costs associated with other GHG or carbon policies. These costs will also be recorded in the GGEADA.

GHG Reporting and Verification

32. In accordance with the OBPS Regulations, Enbridge Gas is required to have it's annual OBPS report verified by a third-party auditor. The verification includes both the GHG emissions and the production from each specified industrial activity during the compliance period that was used in calculating the emissions limit.[24] The emission report and verification report must be submitted by June 1 of the year following each compliance period. For the 2021 OBPS compliance period,

[24] Output-Based Pricing System Regulations (SOR/2019-266), Schedule 5 – Application. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html

verification will be completed and submitted by June 1, 2022. Enbridge Gas anticipates the fees associated with 2021 emissions verification to be $0.05 million.

Bad Debt

33. Enbridge Gas estimates that it will incur approximately $3.72million in incremental bad debt expenses in 2022 based on forecasted costs recoverable from customers as a result of the GGPPA and EPS Regulation, as set out in Exhibit B. While Enbridge Gas has included total 2022 forecast bad debt costs in Table 3, only actual bad debt related to the GGPPA and EPS Regulation will be recorded in the GGEADAs for each rate zone. /c

34. Ongoing COVID-19 related conditions may impact bad debt related to the GGPPA and EPS Regulations beyond what Enbridge Gas would typically forecast. Consistent with the OEB's Decision and Order on Enbridge Gas's 2020 Application, Enbridge Gas will record bad debt expenses for the FCPP related to the COVID-19 emergency in the COVID-specific sub-account so that all matters related to the COVID-19 emergency are recorded in the same account.[25]

Other Miscellaneous Costs

35. Enbridge Gas expects to incur approximately $0.15 million in other miscellaneous costs for customer outreach and communications, training, conferences, travel expenses, memberships and subscriptions associated with the GGPPA, EPS Regulation or other GHG or carbon pricing programs in 2022.

[25] EB-2019-0247, OEB Decision and Order, August 13, 2020, p. 11.

COST RECOVERY

1. The purpose of this exhibit of evidence is to support Enbridge Gas's request to update the impacts of the GGPPA and EPS Regulation in rates for the EGD and Union rate zones, effective April 1, 2022 and to address the proposed allocation and disposition of Enbridge Gas's 2020 FCPP-related deferral and variance account balances, as described at Exhibit C. Accordingly, Enbridge Gas requests approval of: (i) the proposed rate changes on a final basis, effective April 1, 2022;[1] and (ii) the allocation and disposition of the 2020 FCPP-related deferral and variance account balances.

2. This exhibit of evidence is organized as follows:

   1. 2022 FCPP-Related Unit Rates
      - 1.1 2022 Federal Carbon Charge
      - 1.2 2022 Facility Carbon Charge
      - 1.3 Union South – Parkway Delivery Commitment Incentive Costs
      - 1.4 2022 Administration Costs
      - 1.5 Bill Impacts of Carbon Charges
   2. 2020 Deferral and Variance Account Balances
      - 2.1 2020 FCCCVA
      - 2.2 2020 FCCFVA
      - 2.3 2020 GGEADA
      - 2.4 Proposed Disposition of Deferral and Variance Account Balances
      - 2.5 Bill Impacts of Deferral and Variance Account Disposition

   Supporting schedules and appendices:

   - Tab 1: Cost Recovery - EGD Rate Zone
   - Tab 2: Cost Recovery - Union Rate Zones

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[1] Including for First Nations on-reserve customer as per that OEB's determinations regarding the applicability of the FCPP-related charges to Indigenous customers. (EB-2019-0247, OEB Decision and Order, September 23, 2021, p. 31).

1. 2022 FCPP-Related Unit Rates

3. Under the GGPPA, Enbridge Gas is required to remit payment of the Federal Carbon Charge to the Government of Canada for volumes delivered to its customers and for Company Use Volumes. Effective January 1, 2022, Enbridge Gas will also be required to remit payment for any excess emissions related to EPS Volumes pursuant to Ontario's EPS Regulation. These costs will be recovered from customers through the Federal Carbon Charge and Facility Carbon Charge unit rates, respectively.

4. The combined Federal Carbon Charge and Facility Carbon Charge unit rate for the April 1, 2022 to March 31, 2023 period is summarized at Exhibit D, Tab 1, Schedule 1, page 3 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 1, page 3 for the Union rate zones. A summary of the Federal Carbon Charge and Facility Carbon Charge unit rates by rate class for the April 1, 2022 to March 31, 2023 period for the EGD rate zone is provided at Exhibit D, Tab 1, Schedule 1, pages 4 to 5.

1.1 2022 Federal Carbon Charge

5. Effective April 1, 2022, Enbridge Gas proposes to increase the Federal Carbon Charge from 7.8300 ¢/m^3 (or \$40/tCO_2e) to 9.7900 ¢/m^3 (or \$50/tCO_2e), as outlined in the GGPPA and set out at Exhibit A, Table 1.[2]

6. The Federal Carbon Charge is applicable to distribution customers in all rate zones. Entities that are exempt under Part 1 of the GGPPA will not be charged the Federal Carbon Charge. Further, Enbridge Gas will apply 20% of the Federal Carbon Charge to distribution volumes for qualified commercial greenhouse customers, resulting in 80% greenhouse relief. The Federal Carbon Charge is shown as a separate line item on customers' bills, where applicable.

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[2] The GGPPA, Schedule 2 and Schedule 4. https://laws-lois.justice.gc.ca/PDF/G-11.55.pdf

7. Enbridge Gas will track the difference between the Federal Carbon Charge amount collected through rates and the actual costs incurred in the CCCVA for each of the EGD rate zone and the Union rate zones.[3]

8. The Federal Carbon Charge customer-related forecast volumes and costs by rate class for the April 1, 2022 to March 31, 2023 period is set out at Exhibit D, Tab 1, Schedule 1, page 1 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 1, page 1 for the Union rate zones.

1.2 <u>2022 Facility Carbon Charge</u>

9. Enbridge Gas incurs costs of compliance with the GGPPA and EPS Regulation that are associated with its own operations. Enbridge Gas's Facility Carbon Charge costs are incurred in relation to both Company Use Volumes (generated from distribution buildings, boilers/line heaters and NGV fleet volumes) and EPS Volumes (generated from compressor fuel volumes). The estimated Facility Carbon Charge costs for the April 1, 2022 to March 31, 2023 time period are $1.086 million for the EGD rate zone and $5.444 million for the Union rate zones, as detailed at Exhibit B, Tab 1 and at Exhibit B, Tab 2 respectively.

10. Enbridge Gas recovers Facility Carbon Charge costs from rate classes based on in-franchise delivery volumes and ex-franchise transportation volumes. All customers in each rate class are responsible for the Facility Carbon Charge costs, regardless of whether the customer is exempt from the Federal Carbon Charge. Enbridge Gas adds the Facility Carbon Charge to the current approved delivery or transportation charges on customers' bills.

11. Effective April 1, 2022, Enbridge Gas is proposing to increase the Facility Carbon Charge from 0.0066 ¢/m^3 to 0.0070 ¢/m^3 for the EGD rate zone and from

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[3] An amendment to the wording of the approved FCPP-related deferral and variance accounting orders has been proposed in this application which will result in new acronyms for the FCPP-related deferral and variance accounts. Please refer to Exhibit C and Exhibit C Attachment 1 and 2 for more information.

0.0127 ¢/m^3 to 0.0141 ¢/m^3 for the Union rate zones. When expressed in $/GJ, the Facility Carbon Charge remains unchanged at $0.002/GJ for the EGD rate zone and increases from $0.003/GJ to $0.004/GJ for the Union rate zones. The derivation of the proposed 2022 Facility Carbon Charge for each rate zone is set out in Table 1.

Table 1
Derivation of 2022 Facility Carbon Charges

Line No.	Particulars	Rate Zones EGD		Rate Zones Union	
		(a)		(b)	
1	Total Facility Carbon Cost ($000's)	1,086	(1)	5,444	(2)
2	2022 Forecast Volumes (10^3m^3)	15,541,716	(3)	38,669,274	(4)
3	Facility Carbon Charge (¢/m^3) (line 1 ÷ line 2 × 100)	0.0070		0.0141	
4	Facility Carbon Charge ($/GJ) (line 3 ÷ Heat Value × 10) (5)	0.002		0.004	

Notes:
(1) Exhibit B, Tab 1, Schedule 5.
(2) Exhibit B, Tab 2, Schedule 5.
(3) Forecast volumes per Exhibit D, Tab 1, Schedule 1.
(4) Forecast volumes per Exhibit D, Tab 2, Schedule 1.
(5) Conversion to GJ based on heat value adjustment of 38.85 GJ/10^3m^3 for the EGD rate zone. Conversion to GJ based on heat value adjustment of 39.32 GJ/10^3m^3 for the Union rate zones.

12. Enbridge Gas will track the difference between the amount collected through rates and the actual costs incurred in the FCCVA for each of the EGD rate zone and the Union rate zones.[4]

[4] An amendment to the wording of the approved FCPP-related deferral and variance accounting orders has been proposed in this application which will result in new acronyms for the FCPP-related deferral and variance accounts. Please refer to Exhibit C and Exhibit C Attachment 1 and 2 for more information.

13. Facility Carbon Charge forecast volumes by component, costs and unit rate for 2022 are detailed at Exhibit D, Tab 1, Schedule 1, page 2 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 1, page 2 for the Union rate zones.

1.3 Union South – Parkway Delivery Commitment Incentive Costs

14. Enbridge Gas is proposing an update to the Parkway Delivery Commitment Incentive ("PDCI") credit and PDCI costs recovered in Union South distribution rates as a result of the increase in the Facility Carbon Charge from $0.003/GJ to $0.004/GJ for the Union rate zones. Enbridge Gas includes the Facility Carbon Charge in the payment of the PDCI in the Union South rate zone for any continued obligated Daily Contract Quantity ("DCQ") at Parkway. The PDCI credit is set at the M12 Dawn to Parkway rate at 100% load factor, which increased by $0.001/GJ as a result of the increase in the Facility Carbon Charge in the M12 commodity rate. By recovering the Facility Carbon Charge costs in Rate M12, the cost of the PDCI credit increases from $13.573 million to $13.665 million. The increase in the PDCI costs of $0.092 million is recovered in Union South in-franchise delivery rates. The derivation of the Union South in-franchise delivery unit rate changes and the calculation of the PDCI costs are provided at Exhibit D, Tab 2, Schedule 2.

1.4 2022 Administration Costs

15. Administration costs incurred in 2022 will be recorded in the OEB-approved GGEADAs and disposed of in a future proceeding, as described at Exhibit A and Exhibit C.

1.5 Bill Impacts of Carbon Charges

16. For the EGD rate zone, the bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,400 m^3 is an increase of $47.05 per year. Exhibit D, Tab 1, Schedule 2 details customer bill impacts for the EGD rate zone relative to October 1, 2021 QRAM rates (EB-2021-0219).

17. For the Union rate zones, the bill impact of the 2022 carbon charges for a typical residential customer with annual consumption of 2,200 m^3 is an increase of $43.14 per year. Exhibit D, Tab 2, Schedule 3 details customer bill impacts for the Union rate zones relative to October 1, 2021 QRAM rates (EB-2021-0219).

2. <u>2020 Deferral and Variance Account Balances</u>

18. Enbridge Gas is requesting approval of the allocation and disposition of the 2020 final balances in its GGEADA and FCCFVA for each of the EGD and Union rate zones. There is no FCCCVA balance for either the EGD or Union rate zones. A description of 2020 FCPP-related deferral and variance account balances is provided at Exhibit C. The deferral and variance account balances are provided at Exhibit D, Tab 1, Schedule 3 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 4 for the Union rate zones.

2.1 <u>2020 FCCCVA</u>

19. There is no FCCCVA balance for the EGD or Union rate zones.

2.2 <u>2020 FCCFVA</u>

20. Enbridge Gas proposes to allocate FCCFVA balances to rate classes in proportion to actual in-franchise distribution and ex-franchise transportation volumes from January 1, 2020 to December 31, 2020. Unit rates for disposition are derived using actual volumes for the January 1, 2020 to December 31, 2020 time period. The methodology to derive the allocation and disposition unit rates is the same for the EGD and Union rate zones.

2.3 <u>2020 GGEADA</u>

21. Enbridge Gas proposes to allocate GGEADA balances to rate classes in proportion to the number of customers for the EGD rate zone and 2013 OEB-approved administrative and general expenses for the Union rate zones. The proposed allocation methodologies for each rate zone are consistent with the allocations approved in Enbridge Gas's 2019 FCPP-related deferral and variance account

disposition (EB-2019-0247). Unit rates for disposition are derived using actual volumes for the January 1, 2020 to December 31, 2020 time period. The methodology to derive the disposition unit rates is the same for the EGD and Union rate zones.

2.4 Proposed Disposition of Deferral and Variance Account Balances

22. Enbridge Gas proposes to dispose of the balances with a one-time billing adjustment recovered in one month for all customers in the EGD and the Union rate zones.

23. Enbridge Gas proposes to dispose of the approved 2020 FCPP-related deferral and variance account balances with the first QRAM application following the Board's approval, as early as April 1, 2022. Unit rates for disposition can be found at Exhibit D, Tab 1, Schedule 4 for the EGD rate zone and at Exhibit D, Tab 2, Schedule 5 for the Union rate zones.

2.5 Bill Impacts of Deferral and Variance Account Disposition

24. For the EGD rate zone, the bill impact of the proposed deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,400 m^3 is $0.72. Exhibit D, Tab 1, Schedule 5 details the /c
customer bill impacts for the EGD rate zone.

25. For the Union rate zones, the bill impact of the proposed deferral and variance account balance disposition for a typical residential customer with annual consumption of 2,200 m^3 is $0.27 for customers in the Union South rate zone and $0.34 for customers in the Union North rate zone. Exhibit D, Tab 2, Schedule 6 details customer bill impacts for the Union rate zones.

EGD RATE ZONE

TABLE 5: SUMMARY OF 2020 FEDERAL CARBON DEFERRAL AND VARIANCE ACCOUNTS

		Col. 1	Col. 2	Col. 3	Col. 4	
Line	Rate	Federal Carbon Charge - Customer Variance Account[1]	Federal Carbon Charge - Facility Variance Account[2]	Greenhouse Gas Emissions Administration Deferral Account[3]	Total	
					(Col. 1 + Col. 2 + Col. 3)	
		($000's)	($000's)	($000's)	($000's)	
1.1	Balance	-	(40)	1,579	1,539	/c
1.2	Interest	-	(4)	14	11	/c
1	Total	-	(44)	1,593	1,550	/c

Notes:
(1) EB-2021-0209, Exhibit C, Page 8, Paragraph 18.
(2) EB-2021-0209, Exhibit C, Page 8, Paragraph 20 .
(3) EB-2021-0209, Exhibit I.VECC.7.

EGD RATE ZONE

TABLE 6: SUMMARY OF ALLOCATION OF 2020 FEDERAL CARBON DEFERRAL AND VARIANCE ACCOUNTS

		Col. 1	Col. 2	Col. 3	Col. 4	
Line	Rate	Federal Carbon Charge - Customer Variance Account[1]	Federal Carbon Charge - Facility Variance Account[2]	Greenhouse Gas Emissions Administration Deferral Account[3]	Total	
					(Col. 1 + Col. 2 + Col. 3)	
		($000's)	($000's)	($000's)	($000's)	
1.1	1	-	(15)	1,472	1,457	/c
1.2	6	-	(14)	121	106	/c
1.3	9	-	0	0	0	
1.4	100	-	(0)	0	(0)	
1.5	110	-	(3)	0	(3)	
1.6	115	-	(1)	0	(1)	
1.7	125	-	(2)	0	(2)	
1.8	135	-	(0)	0	(0)	
1.9	145	-	(0)	0	(0)	
1.10	170	-	(1)	0	(1)	
1.11	200	-	(1)	0	(1)	
1.12	300	-	(0)	0	0	
1.13	315	-	0	0	0	
1.14	332	-	(7)	0	(7)	
1	Total	-	(44)	1,593	1,550	/c

Notes:
(1) Exhibit D, Tab 1, Schedule 4, Page 1, Table 7.
(2) Exhibit D, Tab 1, Schedule 4, Page 2, Table 8.
(3) Exhibit D, Tab 1, Schedule 4, Page 3, Table 9.

EGD RATE ZONE

TABLE 7: 2020 FEDERAL CARBON CHARGE - CUSTOMER VARIANCE ACCOUNT CLEARANCE UNIT RATES

		Col. 1	Col. 2	Col. 3
Line	Rate	Balance to be Cleared[1]	Interest[2]	Total Balance to be Cleared[3]
				(Col. 1 + Col. 2)
		($000's)	($000's)	($000's)
1.1	1	-	-	-
1.2	6	-	-	-
1.3	9	-	-	-
1.4	100	-	-	-
1.5	110	-	-	-
1.6	115	-	-	-
1.7	125	-	-	-
1.8	135	-	-	-
1.9	145	-	-	-
1.10	170	-	-	-
1.11	200	-	-	-
1.12	300	-	-	-
1.13	315	-	-	-
1.14	332	-	-	-
1	Total	-	-	-

Notes:
(1) The balance by rate class = The total balance in Line 1, Col. 1 x (volume for each rate class in Col. 4 / total volume in Line 1, Col. 4).
(2) The interest amount by rate class = The total interest in Line 1, Col. 2 x (the balance for each rate class in Col. 1 / the total balance in Line 1, Col. 1).
(3) Exhibit D, Tab 1, Schedule 3, Page 1, Line 1, Col. 1.

EGD RATE ZONE

TABLE 8: 2020 FEDERAL CARBON CHARGE - FACILITY VARIANCE ACCOUNT CLEARANCE UNIT RATES

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Line	Rate	Balance to be Cleared[1]	Interest[2]	Total Balance to be Cleared[3]	Actual Volumes (Jan - Dec 2020)	Unit Rate
				(Col. 1 + Col. 2)		(Col. 3 / Col. 4)
		($000's)	($000's)	($000's)	(10^3m^3)	(¢/m^3)
1.1	1	(14)	(1)	(15)	4,894,404	(0.0003)
1.2	6	(13)	(1)	(14)	4,650,326	(0.0003)
1.3	9	0	0	0	0	0.0000
1.4	100	(0)	(0)	(0)	20,111	(0.0003)
1.5	110	(3)	(0)	(3)	981,141	(0.0003)
1.6	115	(1)	(0)	(1)	378,039	(0.0003)
1.7	125	(1)	(0)	(2)	526,029	(0.0003)
1.8	135	(0)	(0)	(0)	65,287	(0.0003)
1.9	145	(0)	(0)	(0)	23,396	(0.0003)
1.10	170	(1)	(0)	(1)	247,430	(0.0003)
1.11	200	(1)	(0)	(1)	189,473	(0.0003)
1.12	300	(0)	(0)	(0)	204	(0.0003)
1.13	315	0	0	0	0	0.0000
1.14	332	(6)	(1)	(7)	2,288,139	(0.0003)
1	Total	(40)	(4)	(44)	14,263,977	

Notes:

(1) The balance by rate class = The total balance in Line 1, Col. 1 x (volume for each rate class in Col. 4 / total volume in Line 1, Col. 4).

(2) The interest amount by rate class = The total interest in Line 1, Col. 2 x (the balance for each rate class in Col. 1 / the total balance in Line 1, Col. 1).

(3) Exhibit D, Tab 1, Schedule 3, Page 1, Line 1, Col. 2.

EGD RATE ZONE

TABLE 9: 2020 GREENHOUSE GAS EMISSIONS ADMINISTRATION DEFERRAL ACCOUNT CLEARANCE UNIT RATES

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	
Line	Rate	2020 Number of Customers	Balance to be Cleared[1]	Interest[2]	Total Balance to be Cleared[3]	Actual Volumes (Jan - Dec 2020)	Unit Rate	
					(Col. 2 + Col. 3)		(Col. 4 / Col. 5)	
			($000's)	($000's)	($000's)	(10^3m^3)	(¢/m^3)	
1.1	1	2,064,531	1,459	13	1,472	4,894,404	0.0301	/c
1.2	6	169,084	120	1	121	4,650,326	0.0026	/c
1.3	9	2	0	0	0	0	0.0000	
1.4	100	9	0	0	0	20,111	0.0000	
1.5	110	335	0	0	0	981,141	0.0000	
1.6	115	20	0	0	0	378,039	0.0000	
1.7	125	4	0	0	0	526,029	0.0000	
1.8	135	40	0	0	0	65,287	0.0000	
1.9	145	22	0	0	0	23,396	0.0001	
1.10	170	21	0	0	0	247,430	0.0000	
1.11	200	1	0	0	0	189,473	0.0000	
1.12	300	1	0	0	0	204	0.0003	/c
1.13	315	0	0	0	0	0	0.0000	
1.14	332	1	0	0	0	2,288,139	0.0000	
1	Total	2,234,071	1,579	14	1,593	14,263,977		/c

Notes:

(1) The balance by rate class = The total balance in Line 1, Col. 2 x (number of customer for each rate class in Col. 1 / total number of customer in Line 1, Col. 1).

(2) The interest amount by rate class = The total interest in Line 1, Col. 3 x (the balance for each rate class in Col. 2 / the total balance in Line 1, Col. 2).

(3) Exhibit D, Tab 1, Schedule 3, Page 1, Line 1, Col. 3.

EGD RATE ZONE

TABLE 10: 2020 FEDERAL CARBON DEFERRAL AND VARIANCE ACCOUNT CLEARANCE
UNIT RATE SUMMARY BY RATE CLASS

The following adjustment is applicable to consumption volumes for the period January 1 to December 31, 2020.

Rate Class	Non-OBPS Unit Rate (¢/m^3)	OBPS[1] Unit Rate (¢/m^3)	
Rate 1	0.0298	0.0298	/c
Rate 6	0.0023	0.0023	/c
Rate 9	0.0000	0.0000	
Rate 100	(0.0003)	(0.0003)	
Rate 110	(0.0003)	(0.0003)	
Rate 115	(0.0003)	(0.0003)	
Rate 125	(0.0003)	(0.0003)	
Rate 135	(0.0003)	(0.0003)	
Rate 145	(0.0002)	(0.0002)	
Rate 170	(0.0003)	(0.0003)	
Rate 200	(0.0003)	(0.0003)	
Rate 300	0.0000	0.0000	/c
Rate 300 Interruptible	0.0000	0.0000	/c
Rate 315	0.0000	0.0000	
Rate 332	(0.0003)	(0.0003)	

(1) Includes Voluntary Participants and Other Exempt Gas Volumes.

EGD RATE ZONE

TABLE 11: 2020 FEDERAL CARBON DEFERRAL AND VARIANCE ACCOUNT CLEARANCE
UNIT RATE BREAKDOWN BY RATE CLASS

The following adjustment is applicable to consumption volumes for the period January 1 to December 31, 2020.

Rate Class		Non-OBPS (¢/m³)	OBPS[1] (¢/m³)	
Rate 1	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0301	0.0301	/c
	Total	0.0298	0.0298	/c
Rate 6	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0026	0.0026	/c
	Total	0.0023	0.0023	/c
Rate 9	Customer-Related	0.0000		
	Facility-Related	0.0000	0.0000	
	GGEADA	0.0000	0.0000	
	Total	0.0000	0.0000	
Rate 100	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0000	0.0000	
	Total	(0.0003)	(0.0003)	
Rate 110	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0000	0.0000	
	Total	(0.0003)	(0.0003)	

Rate Class		Non-OBPS (¢/m³)	OBPS[1] (¢/m³)
Rate 115	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0000	0.0000
	Total	(0.0003)	(0.0003)
Rate 125	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0000	0.0000
	Total	(0.0003)	(0.0003)
Rate 135	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0000	0.0000
	Total	(0.0003)	(0.0003)
Rate 145	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0001	0.0001
	Total	(0.0002)	(0.0002)
Rate 170	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0000	0.0000
	Total	(0.0003)	(0.0003)
Rate 200	Customer-Related	0.0000	
	Facility-Related	(0.0003)	(0.0003)
	GGEADA	0.0000	0.0000
	Total	(0.0003)	(0.0003)

Rate Class		Non-OBPS ($¢/m^3$)	OBPS[1] ($¢/m^3$)	
Rate 300	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0003	0.0003	/c
	Total	0.0000	0.0000	/c
Rate 300 Interruptible	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0003	0.0003	/c
	Total	0.0000	0.0000	/c
Rate 315	Customer-Related	0.0000		
	Facility-Related	0.0000	0.0000	
	GGEADA	0.0000	0.0000	
	Total	0.0000	0.0000	
Rate 332	Customer-Related	0.0000		
	Facility-Related	(0.0003)	(0.0003)	
	GGEADA	0.0000	0.0000	
	Total	(0.0003)	(0.0003)	

(1) Includes Voluntary Participants and Other Exempt Gas Volumes.

EGD RATE ZONE

2020 FEDERAL CARBON DEFERRAL AND VARIANCE ACCOUNT CLEARANCE
Bill Adjustment for April 2022 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
		Volume	Annual Bill Impact for Non-OBPS					Annual Bill Impact for OBPS					
	GENERAL SERVICE	Annual	Unit Rate	Total Adjustment	October 2021 Bill	October 2021 Bill Including Total Adjustment	% Impact	Unit Rate	Total Adjustment	October 2021 Bill	October 2021 Bill Including Total Adjustment	% Impact	
		m^3	¢/m^3	$	$	$	%	¢/m^3	$	$	$	%	
1.1	**RATE 1 RESIDENTIAL**												
1.2	Heating & Water Heating	2,400	0.0298	0.72	1,149	1,150	0.1%	0.0298	0.72	961	962	0.1%	/c
2.1	**RATE 6 COMMERCIAL**												
2.2	Commercial - Heating & Other Uses	22,606	0.0023	0.52	8,840	8,841	0.0%	0.0023	0.52	7,070	7,070	0.0%	/c
2.3	General Use	43,285	0.0023	1.00	15,889	15,890	0.0%	0.0023	1.00	12,500	12,501	0.0%	/c
	CONTRACT SERVICE												
3.1	**RATE 100**												
3.2	Industrial - small size	339,188	(0.0003)	(1.02)	110,977	110,976	0.0%	(0.0003)	(1.02)	84,418	84,417	0.0%	
4.1	**RATE 110**												
4.2	Industrial - small size, 50% LF	598,568	(0.0003)	(1.80)	184,575	184,573	0.0%	(0.0003)	(1.80)	137,707	137,705	0.0%	
4.3	Industrial - avg. size, 75% LF	9,976,121	(0.0003)	(29.93)	2,907,942	2,907,912	0.0%	(0.0003)	(29.93)	2,126,812	2,126,782	0.0%	
5.1	**RATE 115**												
5.2	Industrial - large size, 80% LF	69,832,850	(0.0003)	(209.50)	19,877,665	19,877,456	0.0%	(0.0003)	(209.50)	14,409,753	14,409,544	0.0%	
6.1	**RATE 135**												
6.2	Industrial - Seasonal Firm	598,567	(0.0003)	(1.80)	168,904	168,902	0.0%	(0.0003)	(1.80)	122,036	122,034	0.0%	
7.1	**RATE 145**												
7.2	Commercial - avg. size	598,568	(0.0002)	(1.20)	192,488	192,486	0.0%	(0.0002)	(1.20)	145,620	145,619	0.0%	
8.1	**RATE 170**												
8.2	Industrial - avg. size, 75% LF	9,976,120	(0.0003)	(29.93)	2,667,937	2,667,907	0.0%	(0.0003)	(29.93)	1,886,806	1,886,776	0.0%	

Notes:
Col. 5 = Col. 3 x Col. 4 / 100.
Col. 6 is the approved October 2021 annual bill for Sales Service customer from EB-2021-0219, Exhibit C, Tab 4, Schedule 7.
Col. 7 = Col. 5 + Col. 6.
Col. 8 = Col. 5 / Col. 6.
Col. 10 = Col. 3 x Col. 9 / 100.
Col. 11 is the approved October 2021 annual bill for Sales Service customer from EB-2021-0219, Exhibit C, Tab 4, Schedule 8.
Col. 12 = Col. 10 + Col. 11.
Col. 13 = Col. 10 / Col. 11.