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October 10, 2024

VIA RESS AND EMAIL

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas)
Ontario Energy Board (OEB) File No.: EB-2024-0125
2023 Utility Earnings and Disposition of Deferral & Variance Account Balances – ADR Information Requests

In Procedural Order No. 1 dated July 22, 2024, the OEB scheduled a settlement conference commencing September 16, 2024. Enclosed are responses to supplementary requests for information that were made during the settlement conference process. All parties agreed that it is appropriate for these items to be included on the public record for this proceeding.

In the event that you have any questions on the above, please do not hesitate to contact me.

Sincerely,

Richard Wathy

Richard Wathy
Technical Manager, Regulatory Applications

cc.: D. Stevens (Aird & Berlis)
EB-2024-0125 Intervenors

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Please provide a copy of Table 1 in I.ED-6 that includes a breakdown between the blowdowns that involve venting gas to the atmosphere versus flaring the gas.

b) Please comment at a high level on the approximate proportion of blowdowns on an annual basis that involve venting gas to the atmosphere versus flaring gas for (i) operational blowdowns and (ii) capital blowdowns.

c) I.ED.6 indicates that “blowdown emissions are included within Enbridge Gas’s GHG emissions inventory as reported to provincial and federal GHG reporting programs.” For the purposes of those inventories, how does Enbridge differentiate between gas that is combusted (i.e. flaring) versus gas that is vented in light of the fact that vented gas is far worse?

d) Please add a column to Table 1 in I.ED-6 that includes the GHG emissions therefrom.

e) Does Enbridge ever manage to capture gas for repurposing instead of implementing an operational or capital blowdown? If yes, how and in what circumstances? Could this be expanded?

f) Do other gas utilities ever manage to capture gas for repurposing instead of implementing an operational or capital blowdown? If yes, how and in what circumstances? Could this be adopted by Enbridge?

g) Does Enbridge (or its customers) pay a different amount in carbon costs for one m3 of gas that is vented versus one m3 that is combusted (in light of the very different GHG impacts between those)?

Response:

a) - d)

Enbridge Gas’s response at Exhibit I.ED-6 was provided in the context of UFG reporting. For the purposes of UFG reporting, flaring volumes are not differentiated from blowdown volumes included in the determination of Sendout, since the volume of gas lost from the system is not impacted by this categorization.

For Enbridge Gas's GHG emissions inventories reported under the provincial and federal GHG reporting programs, emissions are reported under the categories of "venting", "combustion", "fugitives", or "flaring". For these purposes, blowdown volumes are differentiated based on whether the volumes are vented to atmosphere (i.e. methane emissions) or combusted via a flare (i.e. carbon dioxide emissions). The associated emissions are calculated in accordance with the appropriate methodologies as laid out under the GHG reporting programs and contribute to the total annual vented and flared emissions reported.

The annual total vented and flared emissions reported under the GHG reporting programs are provided in Table 1 below:

Table 1
Annual GHG Emissions for 2019-2023 in tCO_2e

	Vented	Flared
2023	75,796	1,849
2022	114,533	3,495
2021	120,740	3,087
2020	122,381	3,713
2019	113,417	3,437

e) - f)

To minimize methane emissions, Enbridge has installed permanent blowdown recovery compressors at compressor stations along the Dawn to Parkway system and Enbridge Gas also deploys portable blowdown recovery units.

The permanent blowdown recovery units at compressor stations are designed to capture the blowdown gas instead of venting the gas to atmosphere. These units draw the gas from a compressor plant and re-inject it into the pipeline, allowing the gas to be used within the system, and reducing vented methane emissions into the atmosphere.

Enbridge Gas has also purchased portable blowdown recovery units and is continuing to expand its fleet with the purchase of these units managed through the approved capital envelope. These units are used primarily within the distribution system to capture gas from pipeline segments to be blown down and reinject that gas into active segments of the system, avoiding the release of that gas to atmosphere.

g) Yes. Flared volumes related to Storage and Transmission Operations (STO) are subject to carbon costs under the Ontario EPS program as outlined in the Federal Carbon Pricing Program application (See 2024 Federal Carbon Pricing Program Application, EB-2023-0196), Vented emissions are not captured under the Federal Carbon Pricing Program (FCPP), or the Ontario Emissions Performance Standard (EPS) program and as such, there are no carbon costs applied to vented emissions.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) I.ED-7 seems to suggest that there are usually more unclassified leaks than classified leaks. Is that correct? Why would that be?

b) I.ED-7 seems to suggest that leak volumes are estimated with industry average emission factors that are based on the type of pipe but not on the leak class. Is that correct? Wouldn't it be more accurate to also use the leak class on the assumption that more serious class leaks have higher emission rates? Are there other industry average emission factors that can be used that also account for the class or severity of the leak?

c) If Enbridge develops its own emission factors, will it also use the leak class/size to assess the rates of emissions?

Response:

a) The table provided is representative of work orders related to leaks. A leak may have multiple work orders associated to it that includes confirmation of the leak, monitoring of the leak, repair of the leak, and post-monitoring. Classifications are performed on the confirmation and monitoring parts of the process. The maintenance classification is updated through the lifecycle of leak. A process change in 2022 resulted in an increased volume of above ground leaks that were historically addressed through another repair process that did not require monitoring. This introduction of leaks reported through the revised repair process significantly contributes to the greater number of unclassified leaks. Also, the unclassified category includes "no leak" classifications that is typically used when a leak has been repaired and is no longer a hazard.

b) In Enbridge Gas's response at Exhibit I.ED-14 part g), an example calculation was provided which demonstrated how pipeline leak volumes are calculated using industry average emission factors based on the type (mains, service) and material (plastic, protected steel, unprotected steel) of pipe, as well as the number of leaks found and repaired in the reporting year. Leak class is not used in Enbridge Gas's emissions calculation. There are a few reasons for this:

- National published emission factors do not exist for Enbridge's specific leak classes, as different utilities may classify leaks differently.

- As described in the previously attached Leak Operating Standard, leaks are classified based on degree of hazard to persons or property and are therefore not necessarily an indicator of leak size. For example, proximity to customer residence may impact leak classification due to increased hazard to persons and property, but this would not be expected to correlate with leak volume or emissions.

For calculating emissions, Enbridge Gas uses Emission Factors from the *Canadian Energy Partnership for Environmental Innovation (CEPEI) Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System* (Please see response at Exhibit I.ED-14 part g)), as permitted in the *Guideline for Quantification, Reporting and Verification of GHG Emissions* provided by the Government of Ontario.

Enbridge Gas has proposed to begin developing company-specific emission factors using a handheld flow rate measurement technology for a subset of distribution assets, pending OEB approvals. It is expected that these company-specific emission factors would more accurately reflect Enbridge Gas's operating environment and company leak sizes.

c) Enbridge Gas is currently awaiting OEB approval on the establishment of a deferral account to pilot measurement technologies, including the development of company-specific EFs. As described in our response to part (b), it is not clear that leak class would be an appropriate predictor of emissions.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

These questions are for Highwood:

a) In I.ED.20, Highwood refers to "academic investigations" that have used tower, aerial, or satellite data in large urban centres not for leak detection, but to provide top-down overall emissions rates as one factor to help to assess the accuracy of bottom-up estimates. Please provide a list of these academic investigations.

b) Would Highwood be capable of running a pilot or study to explore the use of top-down emissions rates (e.g. from towers, aerial, or satellite data) in one or two Ontario cities to test the accuracy of bottom-up estimates, including the disaggregation of methane sources (such as a collaboration with a specialist or academic)? If Highwood is not capable of doing so, which other firms or individuals would it recommend contacting to explore this kind of pilot or study?

c) In I.ED-18, Highwood comments on the potential differences between Boston and cities in Ontario. But the study finds that the top-down measurements are much greater than bottom-up measurements in 6 US cities. Is this not at least an indication that the same could potentially be true for some Ontario cities and that this is worthy of exploration?

Response:

a) Examples of studies that include top-down measurements of emissions include:

1. Weller, Zachary D., Steven P. Hamburg, and Joseph C. von Fischer. "A national estimate of methane leakage from pipeline mains in natural gas local distribution systems." *Environmental science & technology* 54.14 (2020): 8958-8967.[1]
2. (referenced in Interrogatory #D-ED-17): *Urban methane emission monitoring across North America using TROPOMI data: an analytical inversion approach*. Sci Rep. 2024 Apr 19;14(1):9041.[2]
3. (referenced in Interrogatory #D-ED-17): *Investigation of the Spatial Distribution of Methane Sources in the Greater Toronto Area Using Mobile Gas Monitoring Systems*.[3]

b) Highwood's analysts have experience working with complex emission data sets and have the expertise to analyze data from top-down emissions. Highwood would be able to disaggregate this data but with a high degree of uncertainty in relative source contributions. If the goal is to develop an estimate of natural gas distribution emissions, then a more accurate method would leverage technologies that can identify and quantify individual leaks as opposed to technologies that measure regional emissions. Highwood is not a measurement technology service provider and would not conduct atmospheric measurements ourselves.

c) It is important to note that city-level measurements may include methane emissions from sources such as beyond-the-meter losses and other non-utility sources. As stated in the Boston study “determining the processes and source types responsible for NG emissions unaccounted for in bottom-up inventories remains a significant challenge”. Without confident source attribution, it would be difficult to determine what portion of any potential underestimations from bottom-up inventories are due to non-utility emission sources. The study cited in the response at Exhibit, I.ED-17 part c), found the waste sector to be the largest emitter of methane in the Greater Toronto Area.

   Furthermore, U.S. utilities operate under different regulatory environments and may have different operational and maintenance practices, and pipeline infrastructure materials compared with Canadian utilities. In our experience, sometimes emissions are higher and sometimes they are lower when top-down estimates are performed in distribution systems. As stated previously, the assumption that the trends observed in the U.S. would be observed in Canada is not necessarily valid in our opinion.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Of all projects in the latest AMP how many (i) have undergone IRP screening and (ii) have not undergone IRP screening. If it is possible to provide a response by project cost category (e.g. more or less than $2 million) that would be helpful.

b) Of all projects in the latest AMP that have passed screening (i) how many have undergone an IRP assessment and (ii) have not undergone an IRP assessment. If it is possible to provide a response by project cost category (e.g. more or less than $2 million) that would be helpful.

Response:

a) All projects in the latest AMP filed October 31, 2023, as part of EB-2020-0091 – Enbridge Gas Asset Management Plan Addendum – 2024, Appendix B - IRP (Updated) have undergone IRP screening.

b) Please see Exhibit H, Tab 1, Schedule 1, pages 5 to 8 of 97 for Section 3 – IRPA Evaluation and AMP Update.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

Can you provide the previous leak standard?

Response:

Please see Attachment 1 for the previous leak standard.

Leak Operating Standard

1 Purpose

The purpose of this standard is to define:

- The frequency of leakage surveys on all pipeline systems.
- The classification of leaks by degree of hazard.
- The response criteria based on leak classification.

2 Terms and Definitions

The following is a list of terms found in this document and their definitions.

at-risk corrosion area: Corrosion areas, identified by Integrity Engineering, that are at a greater risk of developing corrosion leaks. Some examples include areas that have:

- Historically low cathodic protection.
- AC corrosion.
- Pipelines identified as having shielding type coatings.
- Pipelines with a history of leaks due to corrosion.
- Historically unmonitored pipelines.

GHG: Greenhouse gas.

GPI: Gas pipeline inspector.

HCA: High consequence area.

LDAR: Leak detection and repair.

MOP: Maximum operating pressure.

MUB: Multi-unit building.

- Also referred to as multi-unit residential building, multi-family building, vertical subdivision, or garage header.
- Typically, but not limited to, a multi-storey structure containing four or more storeys (i.e., with cooking, eating, sanitary, and sleeping facilities) which may have in-suite natural gas house piping or house piping serving central equipment service rooms only (e.g., penthouse or basement boiler rooms).
- Depending on age, a building could contain piping and valve features complying with the criteria in the TSSA *Guidelines for the Distribution of Natural Gas in Multi-Family Buildings*.
- Some building configurations may have commercial occupancies on the first one or two floors and dwelling units on the upper floors.

rooftop header: Metal piping system installed on a rooftop. This includes all piping running outside the building up to and onto the roof.

STO: Storage & Transmission Operations

TIMP: Transmission Integrity Management Program.

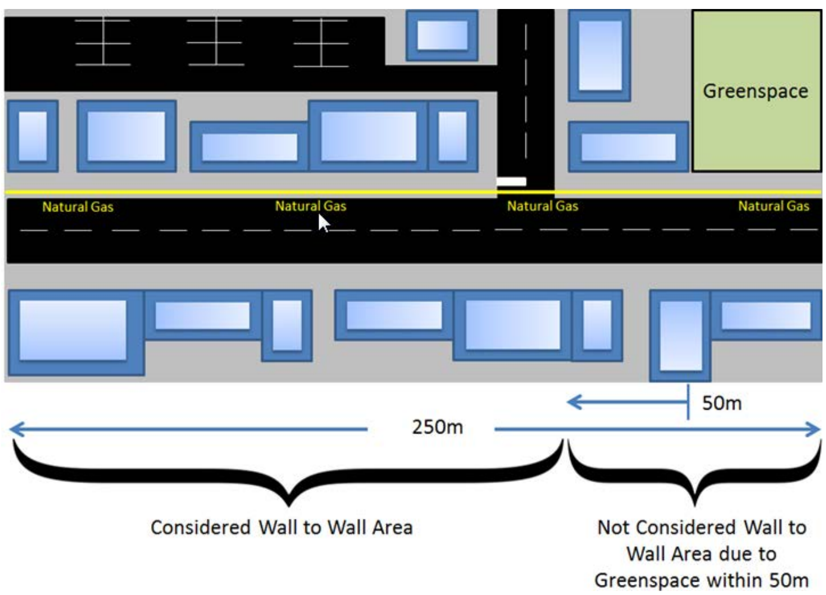
unprotected plant: Pipelines that were intentionally designed without cathodic protection.

wall to wall: Any area where buildings are on both sides of permanent hard surface material (e.g., asphalt, concrete, interlocking brick) that restricts natural gas venting to atmosphere for 50 m (164 ft) or more measured parallel to the pipeline. See Figure 2-1: Wall to wall area on page 2.

The presence of concrete expansion joints does not remove an area from being considered wall to wall.

Tree pits spaced no more than 15 m (50 ft) apart, or a grass median ≥ 0.5m (1.5 ft) wide, are considered a vent point that may remove an area from being considered wall to wall.

Figure 2-1: Wall to wall area



3 Requirements

3.1 Leak Classification and Corrective Actions

Table 3-1: Above- and Below-Grade Leak Classification and Response

Classification	Response
Class A – A leak on any asset that represents an existing or probable hazard to persons or property.	• Designate the leak as an emergency and respond immediately. • The leak must be continually monitored until repaired or mitigated to reduce the leak classification followed by the corresponding monitoring and planned repair.

Classification	Response
Class B – A leak on any asset classified as being nonhazardous at the time of detection but has the potential to become hazardous.	• Repair the leak as soon as possible, not exceeding 70 days for below-grade leaks and 30 days for above-grade leaks. For below grade leaks only: • GDS staff must attend the site of the leak within seven days to verify the classification and begin pre-work. • Until repaired, monitor the leak a minimum of biweekly (15-day window) to ensure it does not intensify to an "A" leak.
Class C – A leak on any non-plastic asset that is nonhazardous at the time of detection and can be reasonably expected to remain nonhazardous.	• Repair the leak as soon as reasonably possible, not exceeding 30 days* for STO assets or 18 months for Distribution Operations assets. • Until repaired, monitor and reassess the leak at a minimum of annually (within 12 months).
Class N – A natural gas release that has been confirmed through investigation to be the result of a natural process and not related to company infrastructure leaks	• If the natural gas release poses a risk to the public or property, the local authorities must be notified.

*C leaks on STO assets that cannot be reasonably repaired within 30 days are to follow the STO leak detection and repair (LDAR) process to determine an allowable extension that meets the Greenhouse Gas (GHG) emissions regulations.

Note
B or C leaks on Distribution Operations assets or B leaks on STO assets, where repair cannot be met within the response timeline, a mitigation plan must be submitted and approved through a Request for Variance prior to the initial due date.

3.2 General Leakage Survey

All piping must be surveyed for leakage in accordance with approved procedures at the frequencies shown in Table 3-2: General Leakage Survey Frequency on page 4. All piping including regulating and gas metering devices, unless such components are specifically delegated to a separate program, must be surveyed for leakage in accordance with approved procedures at the frequencies shown in Table 3-2: General Leakage Survey Frequency on page 4.

Note
Avoid completing surveys when interference of frost caps or severe weather can distort survey results

Table 3-2: General Leakage Survey Frequency

Pipeline and Location	Survey Frequency		
	< 30% SMYS	TIMP not in HCA or ≥ NPS 16 Vital Main	TIMP in HCA
Indoor facilities (not MUBs) – service extensions into buildings up to the demarcation point (meter) • All installations with inside regulation. • All installations with a 5M rotary meter or larger.	Annual[1]	N/A	N/A
Indoor facilities (not MUBs) – service extensions into buildings up to the demarcation point (meter) for installation with a 3M rotary meter or smaller.	10 year[1]	N/A	N/A
Vertical subdivisions, garage headers, MUBs, and rooftop headers	3 year	N/A	N/A
Unprotected plant and copper survey	Annual	N/A	N/A
PE mains and services[2] and protected steel mains and services[2], [3] - installed prior to 2000	4 year	Annual	Semi-annual
Protected steel mains and services[2], [3] installed after 1999 operating at or above 700 kPa	4 year	Annual	Semi-annual
PE mains and services[2] and protected steel mains and services[2] - installed after 1999 and operating at < 700 kPa	8 year	N/A	N/A
PE mains, services, and protected steel – wall to wall	Annual	N/A	N/A
Class A Stations	Annual		
Class B Stations	4 years		
Class C or D Stations installed prior to 2000 or operating at or above 700 kPa	4 years		
Class C or D Stations installed after 1999 and operating at < 700 kPa	8 years		

1 *Record of a pressure test, by an individual carrying a TSSA gas fitters license or who is a certified gas pipeline inspector (GPI) and covering all indoor piping from inlet to meter, may be accepted as a leak inspection completed within the same calendar year of the pressure test.*

2 *Services made of multiple service pipes must be surveyed based on the highest risk pipe.*

3 *STO sites that fall within the GHG survey requirements must be inspected three times annually. This includes all compressor stations and interconnects to other transmission companies.*

3.3 Building Surveys

Where practical, surveys within buildings should be conducted when the ground surface is frozen. Surveys of rooftops should be conducted during spring or fall and should not be completed during inclement weather.

3.4 Wall to Wall Surveys

Where practical, surveys in wall to wall areas should be conducted in advance of the ground becoming frozen.

3.5 Special Surveys

Special surveys are to be conducted for known integrity deficiencies associated with specific types or vintages of pipes or fittings and may include at-risk corrosion areas. The limits of the area affected and the increased survey frequency for the condition will be provided by Integrity Management.

A special leak survey of mains and services will be considered before major street repairs or other major construction in the vicinity of gas pipelines. A leakage survey should also be considered after completion of any major construction projects in the vicinity of gas pipelines.

At the discretion of regional management, more frequent surveys may be required on certain pipelines in areas of unstable soil condition, areas of frequent construction activity, or other atypical circumstances.

A mandatory leak survey is required prior to and after the completion of any blasting that takes place within 30 m of a gas pipeline.

After a large flooding event, tornado, or any significant weather event, consideration is given to completing targeted leak surveys in the affected area.

A mandatory leak survey is required prior to, and following, all increases to piping maximum operating pressure (MOP).

4 References

4.1 Code and Regulation References

- CSA Z662-19, Oil and Gas Pipeline Systems
    - Section 10 – Operating, Maintenance, and Upgrading
        - Clauses 10.3.4.1, 10.3.4.2, 10.3.4.3, 10.4.4, 10.6.1.1, 10.6.1.2, 10.6.4.1
    - Section 12 – Gas Distribution Systems
        - Clauses 12.10.3.1, 12.10.3.3
- TSSA, Guidelines for the Distribution of Natural Gas in Multi-Family Buildings (April 2009)
- TSSA FS-238-18, Oil and Gas Pipeline Systems Code Adoption Amendment (Feb 15, 2018)
- Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) SOR/2018-66
    - Sections 26 to 45

4.2 Gas Distribution and Storage

- Request for Variance (release pending)

5 Document Governance

For document governance purposes, the following tables capture important information related to this document.

Document Control

Table 5-1:

Category	Value
Owned by:	Engineering department
Review interval:	Every 5 years

Revision History

Table 5-2: March 30, 2022 Release

Release Date	Version	Project Number	RFC Number	Prepared By	Approved By
2022-03-30	2.2.0	n/a	RFC 4930	Hooman Zahedi, Supervisor Pipeline Engineering Integration	Tracey Teed Martin, Engineering Director, Engineering & STO
Doc ID		**Scope**	**Document & Section**		**Summary of Changes**
ST-17-96A5-955A		GDS	Section 3.2 - General Leakage Survey		Updated 1st paragraph and Table 3-2.
			Sections 4.3 and 4.4		Sections deleted.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference: Exhibit I.FRPO-19

Question(s):

a) What portion of compressors have blowdown recovery?

b) What more work need to be done to get blowdown emissions down and how much more improvement could be made?

Response:

a) Enbridge Gas has installed permanent blowdown recovery compressors at the four compressor stations along the mainline Dawn-Parkway system. These facilities account for the majority of compressor blowdowns. There are no permanent blowdown recovery compressors installed at the remote storage facilities. The permanent blowdown recovery compressors are connected to approximately 30% of Enbridge Gas' compressor units. Enbridge Gas has flares installed at three facilities which will reduce emissions from blowdowns. Enbridge Gas also owns and deploys portable blowdown recovery units for maintenance and construction activities.

b) Investigations are underway to expand the use of blowdown recovery at Enbridge Gas facilities.

   For the mainline Dawn-Parkway system, permanent blowdown equipment exists and additional piping to this equipment is being considered to expand recovery opportunities at these facilities.

   Permanent blowdown recovery compressors at most remote storage facilities are not reasonable due to infrequent blowdown events.

   To facilitate blowdown recovery for remote storage facilities, additional pipeline connections may need to be installed to connect to permanent blowdown equipment

   Portable blowdown equipment to perform these operations is large, complex, and costly, but will continue to be considered.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

Please outline the allocation of UFG Price Variance deferral account for 2022 and 2023 and the impact on T3 customers.

Response:

The UFG Price Variance Account is allocated to rate classes based on the actual UFG gas supply purchases made by the Company in a given year[1]. UFG purchases are made on behalf of customers for which Enbridge Gas provides fuel and on behalf of customers who provide fuel in kind when the actual UFG variance is greater than the amount of UFG collected through customer supplied fuel. The UFG price variance related to utility supplied fuel is allocated to rate classes in proportion to volumes consistent with the Board-approved allocation of UFG costs, updated for actual activity for 2022 and 2023.

The average actual cost of UFG purchases in 2022 was higher than the OEB-approved reference prices included in rates[2].This resulted in a $9.78 million balance to be collected from ratepayers ($10.441 million including interest). The allocation to T3 customers in 2022 was a collection of $0.087 million[3] as there was a shortfall in the UFG provided through customer supplied fuel compared to the allocation of actual UFG volumes between utility supplied fuel and customer supplied fuel for 2022.

The average actual cost of UFG purchases in 2023 was lower than the OEB-approved references prices included in rates[4]. This resulted in a $0.63 million balance to be refunded to ratepayers ($0.759 million including interest). There is no allocation to T3 customers in 2023[5] as the UFG provided through customer supplied fuel was sufficient compared to the allocation of actual UFG volumes between utility supplied fuel and customer supplied fuel for 2023.

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[1] EB-2019-0105, Exhibit C, Tab 3, p.6, Lines 11-20.
[2] EB-2023-0092, Exhibit E, Tab 1, p.46.
[3] EB-2023-0092, Appendix C, Schedule 3, p.1, Line 24.
[4] EB-2024-0125, Exhibit E, Tab 1, p. 30.
[5] EB-2024-0125, Exhibit F, Tab 3, Schedule 3, p.1, Line 25, updated 20240905.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Preamble:

Minogi repeatedly referenced UFG (and not UAF) in its interrogatories. In EGI's answers, it occasionally distinguishes between UAF and UFG costs. (An example of this can be found in its response to Environmental Defence at Exhibit I, ED-4, Attachment 2.)

Minogi is concerned that EGI's answers to Minogi's questions regarding UFG may somehow fail to capture EGI's complete emissions picture, in particular data relating to the EGD rate zone. This concern arises in part from the answer provided in Exhibit I, ED-4, response a), where Enbridge states that: "UAF is the term used in reference to distribution losses in the EGD rate zone. UFG is the term used in reference to distribution, transmission and storage losses in the Union rate zones."

Question(s):

a) Did EGI's answers to Minogi's interrogatories requesting data relating to UFG include data for both the Union and the Enbridge rate zones?

b) In Exhibit I, ED-4, Attachment 2. What types of costs relating to fugitive emissions (including but not limited to fugitive emissions relating to blowdowns, flaring and venting) does EGI's data under the heading UAF costs capture that EGI's data under the heading UFG costs does not, and vice versa? I.e., what are the differences between the two columns in terms of the types of costs that lie behind the figures provided?

Response:

a) Yes, Enbridge Gas's responses to Minogi's interrogatories relating to UFG included data for both the Union and the EGD Rate Zones.

b) The data provided in Exhibit I.ED-4 for the EGD Rate Zone is limited to distribution losses. For the Union Rate Zones, the data includes distribution, transmission and storage losses. As noted in the pre-filed evidence Exhibit D, Tab 1, page 28, for the EGD Rate Zone, the Company recovers UFG volumes and costs relating to storage operations volumetrically in delivery rates based on a fixed OEB-approved provision. As such, actual UFG volumes are not tracked and no volumetric or cost variances are recorded in a variance account. The OEB-approved provision for storage related UFG losses for 2023 was 20,365 10^3m^3. The associated cost is priced at the relevant PGVA reference price. In 2023, the cost for EGD storage related UFG volumes was approx. $4.2 million.

Another difference in the data within Exhibit I.ED-4 Attachment 2 is that for the EGD rate zone, the data for 1991-2023 are utility volumes only (per footnote 1) and for the Union Rate Zones, the reported volumes include utility and non-utility volumes (per footnote 2).

In pre-filed evidence Exhibit D, Tab 1, page 25 it is noted that volumes associated with operational blowdowns are removed from Sendout and as such do not contribute to calculated UFG volumes. This was the historical practice for the Union Rate Zones. For the EGD Rate Zone, this practice was implemented in 2023, so historical UFG volumes for the EGD Rate Zone prior to 2023 do include volumes associated with operational blowdowns.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Exhibit I, ED-4, Attachment 2. What is EGI's explanation for the relative spike in costs that took place in 2022?

Response

The relative spike in costs that took place in 2022 was driven by a combination of higher UFG volumes as well as higher gas supply commodity costs.

As noted in the response at Exhibit I.STAFF-12, the reduction in 2023 UFG cost relative to 2022 of $45.5 million is driven by lower commodity cost in 2023 for approximately $25.6 million, and lower UFG volumes in 2023, as shown at Exhibit E, Tab 1, page 27, Table 2, for approximately $19.9 million.

The response at Exhibit I.STAFF-13 notes that the drop in the 2023 actual average cost relative to 2022 is driven by the lower gas supply commodity costs in 2023 versus 2022. The lower gas supply commodity costs are demonstrated in the lower OEB-approved reference prices in 2023 as shown in Table 2 of Exhibit E, Tab 1, page 32, line 1, in comparison to the 2022 OEB-approved reference prices in the 2022 Utility Earnings and Disposition of Deferral & Variance Account Balances proceeding at EB-2023-0092 Exhibit E, Tab 1, page 48, line 1.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Exhibit I, ED-4, Attachment 2. What is EGI's explanation for the relative decline in costs that took place in 2020?

Response

The primary driver of lower costs in 2020 was due to lower UFG volumes in 2020. In EB-2022-0110 2021 Utility Earnings and Disposition of Deferral & Variance Account Balances Application, Exhibit E, Tab 1, page 35, it is noted that there was a decrease in UFG volumes in 2020 with an offsetting increase in 2021.