ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended (the "**Act**"); and in particular section 90(1) and section 97 thereof**;**

AND IN THE MATTER OF an application by Enbridge Gas Inc. for an order granting leave to construct natural gas pipelines in the Municipality of Chatham Kent and Essex County.

EB-2022-0157

CROSS-EXAMINATION COMPENDIUM

THREE FIRES GROUP INC.

November 13, 2023

SUMMARY OF APPLICATION

1. In response to increasing natural gas demand growth in the areas served by Enbridge Gas's Panhandle Transmission System ("Panhandle System"), Enbridge Gas is proposing to construct the following facilities, collectively referred to as the Panhandle Regional Expansion Project ("Project"):

   - Approximately 19 km of Nominal Pipe Size ("NPS") 36 natural gas pipeline with a Maximum Operating Pressure ("MOP") of 6040 kPag from the existing Enbridge Gas Dover Transmission Station in the Municipality of Chatham-Kent to a new valve site in the Municipality of Lakeshore; and, /U
   - Ancillary measurement, pressure regulation, and station facilities within the Township of Dawn Euphemia and in the Municipality of Chatham-Kent.

2. The Panhandle System is comprised of transmission pipelines to transport natural gas between Enbridge Gas's Dawn Compressor Station ("Dawn"), located in the Township of Dawn-Euphemia and the Ojibway Valve Site ("Ojibway"), located in the City of Windsor. The Panhandle System feeds distribution systems serving residential, commercial, and industrial markets in the municipalities of Dawn-Euphemia, St. Clair, Chatham-Kent, Windsor, Lakeshore, Leamington, Kingsville, Essex, Amherstburg, LaSalle, and Tecumseh ("Panhandle Market").

3. The current (Winter 2022/2023) Panhandle System capacity is 737 TJ/d. Enbridge /U
   Gas plans its facilities to reliably serve firm in-franchise customer demand on the coldest observed day on record, which is referred to as the "Design Day." Enbridge Gas's current Design Day demand forecast indicates that the Panhandle System demand will exceed capacity by 66 TJ/d beginning in Winter 2024/2025, which increases to 156 TJ/d by Winter 2028/2029. As a result of this demand growth,

there is a need for capacity to meet the forecasted firm customer demands by November 1, 2024 and beyond.

4. Enbridge Gas's current Panhandle System Design Day demand forecast is developed from the contract demand and customer attachment forecasts. Growth is forecast to occur across the entire Panhandle System with concentration in the Leamington-Kingsville and Windsor areas. Details of the Enbridge Gas growth forecast for contract and general service rate classes are provided in Exhibit B, Tab 1.

5. The Company's Panhandle System network analysis and determination of the need to mitigate the forecasted shortfall are discussed in Exhibit B, Tab 2. This network analysis has identified that the operational requirements of the Panhandle System cannot be met for Winter 2024/2025. To continue to provide reliable firm service to new and existing general service and contract rate customers, Enbridge Gas must address this forecasted shortfall beginning November 1, 2024. The optimal solution to address the forecasted shortfall is the proposed Project, which targets the largest pressure bottleneck on the current Panhandle System. /U

6. The proposed Project is designed to reliably serve the increased demands for firm service in the Panhandle Market including, in particular, from the greenhouse, automotive, and power generation sectors. Reliably serving this increased demand is vital to the continued economic well-being of the region. The additional capacity of 168 TJ/d resulting from the Project will support the continued reliable and secure delivery of natural gas to the growing residential, commercial, and industrial customer segments within the Panhandle Market. /U

7. Affordable energy is critical to the development and prosperity of communities and businesses. Affordable energy promotes and enables growth in the economy, provides savings for residential customers and helps maintain the global competitiveness of Ontario's businesses. Natural gas is the most affordable energy source available to customers.

8. The Project will directly support job growth, increase property tax revenue for the affected municipalities and increase tax revenue for the province. Furthermore, as indicated by various letters of support received by Enbridge Gas (see Exhibit B, Tab 1, Schedule 1, Attachments 3 – 7), the Project has broad support from regional /U municipalities as well as major customer groups. For example:

   The Chatham-Kent Chamber of Commerce said:

   > "In order for future growth in Chatham-Kent area to be realized, sufficient natural gas infrastructure will be required and expansion of service is necessary to support current and planned economic developments in the region, particularly in the fast-growing greenhouse, manufacturing sectors and, with that, residential growth of the Chatham-Kent, Windsor and Essex County area. This project is critical for attracting new and aspiring developments by guaranteeing increased access to energy needed for all sectors of the local economy."

   Mayor Drew Dilkens, on behalf of the City of Windsor, wrote:

   > "… this project represents an investment in the future of our region. Simply put, (the) project ensures that Enbridge Gas continues to meet the ongoing needs of longstanding businesses and industries in Windsor, at a time we are experiencing exponential growth. This project is also critical for attracting future developments by guaranteeing increased access to energy for all sectors of the local economy."

   The Ontario Greenhouse Vegetable Growers Association ("OGVG"), stated:

   > "Natural gas is necessary now more than ever, as we implement technology that will allow more greenhouse farms to grow year-round, effectively extending the annual production cycle. This directly translates to more affordable food, more jobs created and ultimately, robust economies in the communities in which we serve."

FCA Canada Inc (Stellantis), which has recently announced several expansions to their automotive manufacturing operations within Southwestern Ontario, stated:

> "This Project is also critical for attracting future investment and developments by guaranteeing increased access to energy for all sectors of the local economy. As Stellantis looks to its future, it is imperative that we have reliable and affordable access to energy, which we trust the (Enbridge) Gas Panhandle Regional Expansion Project will deliver."

9. With leave of the OEB, construction of the NPS 36 pipeline and ancillary measurement, pressure regulation, and station facilities is planned to commence in Q1 2024 to allow these facilities to be placed into service by November 2024. The capacity provided by the Project is intended to ensure the growing Panhandle Market has sufficient capacity until Winter 2029/2030. /U

10. Through the consideration of alternatives, Enbridge Gas has determined that the proposed Project represents the best way to address the identified needs. In particular, Enbridge Gas considered several facility, non-facility and hybrid alternatives and determined that the proposed Project is the optimal solution for meeting the forecasted system need and is in the best interests of Enbridge Gas's customers. The assessment of Project alternatives is described in Exhibit C.

11. Enbridge Gas is proposing to construct the Project following its standard construction practices which have been refined over many years. The design of the pipeline will meet or exceed all applicable Canadian Standards Association code requirements. Experienced contractors familiar with Enbridge Gas's design and construction practices are available to construct the proposed facilities. Detailed information about the proposed Project, the construction schedule, and related engineering and construction specifications can be found in Exhibit D.

PROJECT UPDATE SUMMARY

1. On June 10, 2022, Enbridge Gas applied to the OEB pursuant to section 90(1) of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, Schedule B (the “Act”), for an Order granting leave to construct the following:

   - Approximately 19 km of Nominal Pipe Size (“NPS”) 36 natural gas pipeline with a Maximum Operating Pressure (“MOP”) of 6040 kPag from the existing Enbridge Gas Dover Transmission Station in the Municipality of Chatham-Kent to a new valve site in the Municipality of Lakeshore (“Panhandle Loop”); and,
   - Approximately 12 km of NPS 16 natural gas pipeline with a MOP of 6040 kPag in the Municipality of Lakeshore, the Town of Kingsville, and the Municipality of Leamington (“Leamington Interconnect”).

2. Enbridge Gas also planned to construct ancillary measurement, pressure regulation, and station facilities within the Township of Dawn Euphemia, in the Municipality of Chatham-Kent, and valve-site station facilities within the Town of Kingsville and the Municipality of Leamington.

3. On July 4, 2022, the OEB issued a Notice of Hearing and subsequently established initial procedural steps in Procedural Order No. 1 which was issued on August 12, 2022. Throughout the months that followed, the OEB, Enbridge Gas, and intervening parties engaged in a robust review of the Company’s Application, including extensive discovery via written interrogatories, a virtual technical conference and written undertakings.

4. On November 10, 2022, the OEB issued Procedural Order No. 3 which set out procedural timelines including the date by which Enbridge Gas’s Argument-in-Chief was due to be filed with the OEB and sent to intervening parties (December 5, 2022).

5. On December 5, 2022, Enbridge Gas notified the OEB and parties that, due to unexpected circumstances, the Company was not in a position to proceed with the filing of its Argument-in-Chief. The Company went on to request that the OEB place the Application into abeyance as it had identified potentially material increases to certain components of the estimated Project costs, and that it was in the process of

B. Updated Demand Forecast

15. Following the Application being placed into abeyance in December 2022 and given market indications that demand for natural gas continued to evolve, Enbridge Gas launched an additional Expression of Interest ("EOI") and Reverse Open Season ("ROS") to re-assess and re-confirm customer demand for natural gas services (firm and/or interruptible) in the Project area from 2024 to 2031.

16. Enhancements were made to the EOI/ROS process to gain further clarity and certainty regarding the nature of customer interest/bids. More specifically, customers who responded to the EOI/ROS were asked to provide additional information regarding the viability of interruptible service as an alternative to new firm service, including whether they would be more inclined to consider interruptible service over new firm service if the ability to negotiate lower than posted interruptible rates was available. Customers were also asked to confirm that their EOI bid amounts are inclusive of all future expected natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternatives.

17. Using the results of the additional EOI/ROS, an updated demand forecast to Winter 2030/2031 was developed which reflects decreases in customer demand, including:

- Winter 2023/2024 customer demands decreased by 14 TJ/d, from 744 TJ/d to 730 TJ/d.
- The 5-year demand forecast (i.e., the total forecast demand in Winter 2028/2029) decreased by 40 TJ/d, from 932 TJ/d to 892 TJ/d.[1]

18. The impact to Project scope and in-service date caused by the updated demand forecast combined with the increase in the Panhandle System's capacity realized for 2022/2023 (described in Section C below) is described in Section E below. More information regarding the updated EOI/ROS and demand forecast can be found at Exhibit B, Tab 1, Schedule 1.

[1] As described in Section C of this Exhibit, the existing capacity of the Panhandle System is 737 TJ/d.

C. Updated Panhandle System Capacity

19. Following the Application being placed into abeyance in December 2022 (at the Company's request), Enbridge Gas re-evaluated existing system capacity based on the impact of actual 2022 customer demands, updated forecast demands, updated SWAHV, and supply volumes on the Panhandle System.[2] As a result of this assessment the Company found that:

    i. The nature, magnitude and location of actual customer demands has changed and the Company expects there to be less pressure loss on the existing system, and thus greater existing/remaining capacity, than originally estimated. The existing Panhandle System is now forecasted to be able to serve an additional 27 TJ/d of capacity compared to the previous modelling and forecasts, until Winter 2024/2025 at which time customer demands are expected to exceed the system's capacity.
    ii. Panhandle System capacity decreased by 3 TJ/d due to the updated SWAHV.
    iii. There were no changes to system capacity due to supply volumes and their locations.

20. The outcome of the changes described above increased the existing Panhandle System capacity by 24 TJ/d from 713 TJ/d to 737 TJ/d. The impact to the Project's in-service date due to this increase in Panhandle System capacity combined with the decrease in customer demand (described in Section B above) is described in Section E below.

D. Contributions in Aid of Construction

21. Following the OEB's remarks in Procedural Order No. 4 regarding CIAC, Enbridge Gas account managers conducted outreach to customers who indicated their intention to submit an EOI bid. Customers were asked about the impact a requirement for CIAC would have on their demands for new/incremental service. The themes of the feedback are as follows:

---

[2] Existing system capacity is based on the existing pipeline facilities, customer demand volumes and location, the energy content of natural gas (also known as the system-wide average heating value, or "SWAHV"), and supply volumes and location.

- Customers submitting EOI bids for new/incremental service were generally doing so under the assumption that the OEB would apply the established regulatory framework for transmission system expansion projects, which does not require CIAC, consistent with similar projects constructed in the past. Customers generally indicated opposition to being required to provide CIAC to support transmission system expansion in this instance.
- No customer indicated that they would be willing to provide CIAC for a transmission system expansion project without understanding the magnitude of the CIAC and the unique justification for its selective application in this instance.

22. On this basis, and for the reasons already set out on the record for the current Application, the Company re-iterates that it is not appropriate to require CIAC from specific customers for the proposed Project because, as a transmission system, the Panhandle System transports natural gas for the benefit of all customers within the Panhandle Market – rather than individual or specific customers.[3]

23. The Panhandle System transports natural gas supply and stored volumes from the Dawn Hub and upstream supply basins into and through Enbridge Gas's integrated storage and transmission systems, and ultimately distribution systems to end use customers. Enbridge Gas's transmission systems are connected to multiple upstream supply basins, storage facilities and markets through ex-franchise transmission pipelines. This provides Enbridge Gas's ratepayers access to multiple sources of economic natural gas supply. As a result, Ontario ratepayers pay a lower cost for natural gas supply than they otherwise would and rarely experience disruption of firm natural gas services. Accordingly, the continued expansion of the Panhandle System will allow existing and future customers to experience the same diversity, reliability, and resiliency of Enbridge Gas's integrated natural gas storage and transmission systems. This results in increased energy price stability and competitiveness, and mitigates supply shortfall or disruption to the benefit of all Ontario natural gas customers.

E. Outcome and Summary

24. The combined effects of the decrease to the customer demand forecast (as described in Section B above) and an increase in the existing system capacity (as

[3] Exhibit JT1.3

PROJECT NEED

1. The purpose of this Exhibit is to describe the need and timing for the proposed Project.

2. This Exhibit is organized as follows:
   A. Introduction
   B. Existing System Capacity
   C. Incremental Demand
      i. Contract Rate Growth Forecast
      ii. General Service Growth Forecast
      iii. Total Panhandle System Growth Forecast
   D. System Growth Benefits
   E. Project Timing and Enbridge Gas Growth Plans
   F. Conclusion

A. Introduction

3. The proposed Project is in response to increasing natural gas demand growth in the areas served by the Panhandle System. Specifically, Enbridge Gas is forecasting continued demand growth from commercial, industrial, and residential customers located in the areas west of Dawn, with concentrations in the Municipalities of Windsor, Leamington, and Kingsville.

B. Existing System Capacity

4. The current (Winter 2022/2023) Panhandle System capacity is 737 TJ/d. The forecasted firm demand on the Panhandle System for Winter 2022/2023 is 698 TJ/day. Enbridge Gas's current Design Day demand forecast, discussed in detail below, indicates that the Panhandle System demand will increase by 32 TJ/d to 730 TJ/d by Winter 2023/2024, and by an additional 72 TJ/d to 802 TJ/d in Winter 2024/2025. As a result of this growth, there is a need for capacity to meet the forecasted firm customer demands by November 1, 2024 and beyond. /U

5. Details of the Company's Panhandle System network analysis and determination of the need to mitigate the forecasted shortfall are discussed at Exhibit B, Tab 2, Schedule 1.

C. Incremental Demand

6. The firm demand for natural gas from new and existing general service and contract rate customers has continued to grow on the Panhandle System over the past decade. Prior to 2017, Enbridge Gas was able to reinforce the Panhandle System by constructing downstream facilities, such as the Leamington North Loop (Leamington Expansion Phase I project in 2013[1] and Phase II project in 2016[2]), upsizing of pipeline between Ruscom and Patillo from NPS 16 to NPS 20 through the Panhandle NPS 16 Replacement Project between 2014 and 2016[3], and by relying on Enbridge Gas's firm gas supply arriving at Ojibway to serve markets within the Windsor region.

7. Starting in 2017, Enbridge Gas expanded the Panhandle System to meet increasing demands for firm service from Enbridge Gas's distribution systems which serve the in-franchise markets in the Municipalities of Dawn-Euphemia and St. Clair, Chatham-Kent, Lakeshore, Essex, Tecumseh, Leamington, Kingsville, LaSalle, Amherstburg and Windsor (together "the Panhandle Market"). The Panhandle Reinforcement Project ("PRP")[4] was placed into service on November 1, 2017, to serve forecasted demand growth out to Winter 2021/2022, including unfulfilled demand requests from the Leamington Expansion Phase II project.

8. In 2018, Enbridge Gas's Kingsville Transmission Reinforcement Project ("KTRP")[5] was advanced by 3 years from the initial forecasted in-service date of November 1, 2022 to November 1, 2019. The forecasted Panhandle System capacity shortfall at that time occurred in Winter 2020/2021, but the Project was placed into service in 2019 to alleviate the need for incremental downstream distribution system expansion. The KTRP facilities were designed to meet forecasted demand in the Panhandle Market out to Winter 2025/2026, based on the best information then available.

9. Consistent with these past experiences, significant growth has continued within the Panhandle Market and demand is forecast to exceed the Panhandle System capacity sooner than anticipated, resulting in the need to address a forecasted system capacity shortfall by November 1, 2024. /U

[1] EB-2012-0431
[2] EB-2016-0013
[3] EB-2013-0420
[4] EB-2016-0186
[5] EB-2018-0013

10. Enbridge Gas's current Panhandle System Design Day demand forecast is developed from the contract demand and customer attachment forecasts. Growth is forecast to occur across the entire Panhandle System with concentration in the Leamington-Kingsville and Windsor areas. Details of the Enbridge Gas growth forecast for contract and general service rate classes are provided in the sections below.

i. Contract Rate Growth Forecast

2021 Expression of Interest and Reverse Open Season – Approach and Outcomes

11. The contract rate (Rate M/BT4, Rate M/BT5, Rate M/BT7, Rate T-1 and Rate T-2) demand accounts for approximately 55% of firm demand served by the Panhandle System as of Winter 2021/2022. Based on early indications of incremental demand obtained by informal contract rate customer outreach, Enbridge Gas launched an Expression of Interest ("EOI") process in February 2021 to formally gauge interest for incremental growth on the Panhandle System[6]. An email notification announcing the EOI was sent to all existing contract rate customers, all large volume general service rate M2 customers within the Area of Benefit, and the direct purchase marketer community. The EOI and related bid forms were also posted on Enbridge Gas's website. The EOI is provided as Attachment 1 to this Exhibit. /U

12. The EOI included a map, shown in Figure 1 below, depicting the Area of Benefit. The Area of Benefit included all of Essex County as well as the western portion of the Municipality of Chatham-Kent.

[6] Enbridge Gas's Expression of Interest process is intended to collect and aggregate all potential customer demand changes in a targeted Area of Benefit, so that an optimized facility or non-facility solution can be developed and implemented in a timely manner. In addition to soliciting requests for firm capacity and conversion of existing interruptible capacity to firm, it allows for customers to express interest in additional interruptible capacity. Existing customers are also provided an opportunity to turn back or de-contract existing firm or interruptible capacity. The net of all changes requested through the process supports the generation of an informed demand forecast for the Area of Benefit.

Figure 1 – Expression of Interest Area of Benefit Map

13. Customers were invited to express their interest for incremental Panhandle System capacity by submitting a bid form that included details of their location, expected new or incremental firm or interruptible hourly natural gas requirements, and expected timing. The EOI bid forms were non-binding and were intended to gather information on potential customer demands over the 2023-2033 period.

14. To provide clarity on the EOI process and ensure customers understood the information requested on the EOI bid forms, Enbridge Gas followed up with contract rate customers to discuss the EOI. Meetings were also held with local economic development officials and other external stakeholders to ensure they were informed of the intent and timelines of the EOI and to answer any questions regarding the EOI process and bid forms.

15. The EOI closed on March 31, 2021. All bids received were acknowledged via email from Enbridge Gas. In total, 44 bid forms from interested parties were received, indicating over 318 TJ/d of interest for incremental firm and interruptible demand over the 2023-2033 period. Of the 44 bid forms received, 43 of the requests for additional capacity were from customers in the greenhouse sector and one request was from a large power generator (Brighton Beach Power L.P. (doing business as Atura Power ("Atura")). The 43 requests from the greenhouse sector came from 38

greenhouse customers. Several greenhouse sector customers submitted multiple bid forms, each representing a specific location for which new or incremental service was requested.

16. The response to the EOI far exceeded Enbridge Gas's initial incremental demand projections and confirmed that demand for natural gas in the region is expected to grow significantly over the next 10 years.

17. The interest for incremental firm service received from the greenhouse sector through the EOI process is consistent with IESO reports identifying incremental demand for electricity driven by anticipated growth in the greenhouse sector in Windsor-Essex and Chatham-Kent.[7] Greenhouses require electricity primarily for lighting, but also require natural gas for heating, power generation, and other process-related needs. Increased awareness of the importance of food security and affordability, advances in technology enabling year-round crop growing, and the addition of new crop types to greenhouses are expected to contribute to an increase in greenhouse acreage developed in the region over the next decade.

18. After the close of the EOI process, Enbridge Gas was approached by a large industrial customer from the automotive industry (Stellantis N.V. ("Stellantis")) which requested incremental natural gas service to their planned large scale electric vehicle ("EV") battery manufacturing facility in Windsor, Ontario. This facility is part of a joint-venture agreement between LG Energy Solution ("LGES") and Stellantis and will operate under the legal name NextStar Energy Inc. ("NextStar"). Because Enbridge Gas was in the process of finalizing a contract with NextStar this demand was included in the contract rate demand forecast for the Project. Enbridge Gas has since finalized a contract with NextStar for service commencing in September 2023, using existing capacity.

/U

19. To promote the most efficient means of meeting the growing demands in the Panhandle Market, including minimizing the need for incremental facilities and thereby the overall costs to ratepayers, Enbridge Gas provided existing contract rate and large volume general service customers the opportunity to turnback firm or interruptible capacity or convert existing firm capacity to interruptible capacity in the Area of Benefit on two separate occasions.

[7] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/2021-Annual-Planning-Outlook.ashx

20. First, on the EOI bid form, customers in the Area of Benefit were provided an opportunity to turn back or de-contract existing firm or interruptible capacity. Any capacity turned back can be used to serve additional growth prior to the addition of new facility or non-facility projects. Enbridge Gas received no interest to turn back capacity as part of the EOI process.

21. Second, a follow-up Binding Reverse Open Season was issued on September 29, 2021 and closed on October 15, 2021. The Binding Reverse Open Season can be found at Attachment 2 to this Exhibit. Email notification of the Binding Reverse Open Season was sent to all existing contract rate customers in the Area of Benefit, as well as to the energy marketer community, including a link to further information located on Enbridge Gas's website. Enbridge Gas received no requests to turn back capacity as part of the Binding Reverse Open Season.

22. In addition to the EOI and Binding Reverse Open Season processes, customers can de-contract firm or interruptible capacity provided they meet the notice requirements per the terms and conditions of their distribution contract. Enbridge Gas has not received any communications from customers requesting to reduce their existing firm or interruptible contract demands since the close of the Binding Reverse Open Season. Enbridge Gas does not expect existing contract rate customers will turn back firm capacity, as demand for natural gas in the region continues to increase.

2023 Expression of Interest and Reverse Open Season – Approach and Outcomes

23. On February 23, 2023, Enbridge Gas launched a second non-binding EOI and concurrent binding Reverse Open Season (ROS) for the Panhandle Market (see Figure 1 above for the Expression of Interest Area of Benefit Map). The purpose of the second EOI was to re-confirm customer interest in incremental capacity on the Panhandle System following the Project's leave to construct application being placed into abeyance in December 2022 (see Attachment 8 to this Exhibit for the February 2023 EOI form). Customers who responded to the EOI were also requested to provide additional information regarding the viability of interruptible service as an alternative to new firm service, including whether they would be more inclined to consider interruptible service over new firm service if the ability to negotiate lower than posted interruptible rates was available. Customers were also asked to confirm that their EOI bid amounts were inclusive of all future expected natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternative options. /U

24. The ROS provided existing contract customers another opportunity to formally de-contract existing firm or interruptible capacity (see Attachment 9 to this Exhibit for the February 2023 ROS form). The ROS also provided existing customers the opportunity to request to convert existing firm service to interruptible service. It should be noted that regardless of formal ROS initiatives such as this, customers always have the ability to request changes to their existing contract parameters including de-contracting existing capacity, provided appropriate notice is given per the terms and conditions of their distribution contract. /U

25. To provide clarity and respond to any questions regarding the EOI and ROS process, Enbridge Gas account managers directly contacted each contract rate customer in the Panhandle Market. In addition to direct outreach, all existing contract customers were invited to attend an in-person meeting held on March 7, 2023, and/or a virtual meeting held on March 23, 2023. A meeting with local economic development officials was also held on March 2, 2023, to inform them of the process and timelines, and to answer any questions related to the forms. /U

26. The EOI and ROS process closed on April 6, 2023, thirty business days following its launch. All bids received were acknowledged via email from Enbridge Gas. A total of 42 EOI bid forms were received from 39 entities, indicating approximately 197 TJ/d of interest over the 2024-2033 period. The 197 TJ/d is incremental to the capacity that has already been contracted for by customers via the 2021 EOI process and through the normal course of business since the close of the 2021 EOI process. Of the 42 EOI bids received, 38 bids were from the greenhouse sector, 2 bids were from the power sector and 2 bids were from the commercial sector. The results of the EOI can be found in Table 1. /U

Table 1 – 2023 EOI Bid Summary by Year (m³/hr) /U

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
New/Incremental Firm	52,432	84,503	37,807	25,802	32,952	17,204	13,732	12,547	7,277	2,325	286,581
Interruptible to Firm Conversion	66	8,484	-	-	-	-	-	-	-	-	8,550
Firm Turnback	-	-	-	-	-	-	-	-	-	-	-
Firm to Interruptible Conversion	-	-	-	-	-	-	-	-	-	-	-
Net New/Incremental Firm (by year)	**52,498**	**92,987**	**37,807**	**25,802**	**32,952**	**17,204**	**13,732**	**12,547**	**7,277**	**2,325**	**295,131**
Net New/Incremental Firm (cumulative)	52,498	145,485	183,292	209,094	242,046	259,250	272,982	285,529	292,806	295,131	
TJ/day (by year)	**33**	**71**	**24**	**16**	**21**	**11**	**9**	**8**	**5**	**1**	**197**
TJ/day (cumulative)	33	104	127	143	164	175	183	191	196	197	

Notes:
1) The volumes received through the 2023 Expression of Interest process were in cubic meters of gas per hour (m3/hr).
2) The 2023 Expression of Interest results, combined with the previously contracted volumes from the 2021 Expression of Interest process were used to generate an informed demand forecast.

27. *EOI results – existing interruptible service to firm service conversion:* Customers requesting to convert existing interruptible service to firm service were asked to identify the driving factors behind their conversion request on the EOI bid forms. Of the two bids received for interruptible to firm service conversion, one indicated that they wanted to reduce their reliance on back-up fuel sources due to increased risk of disruption/crop loss, and the other referenced contractual obligations with the IESO. /U

28. *EOI results – viability of interruptible service as an alternative to new firm service:* Customers who submitted EOI bids for new/incremental firm service were asked to provide information regarding the viability of interruptible service as an alternative to new firm service. Of the 42 EOI bids received, only 2 bids (3% of total EOI interest) indicated that interruptible service was a viable alternative and that they could rely on alternate fuel sources during an interruption event. It should be noted that for those two bids, interruptible service was not requested, nor was there an accompanying ROS request to convert existing firm service to interruptible service. The firm demands from these two bids were not included in the updated demand forecast. For the bid forms received where customers indicated why interruptible service was not a viable option, reasons included: disruption to operations/productivity impacts; potential for crop loss/production loss; contractual obligations with the IESO/regional power generation; increased cost/availability/emissions associated with alternate fuel sources; installation and maintenance costs of backup fuel systems; and, CO_2 requirements for greenhouses. /U

29. *EOI results – interruptible service as an alternative to new firm service if negotiable interruptible rates were available:* Customers were also invited to indicate whether they would be more inclined to consider interruptible service over new firm service if the ability to negotiate lower than posted interruptible rates was available. There were five bids received (8% of total EOI interest, inclusive of the two bids referenced in the paragraph above) where customers indicated they would consider interruptible /U

service as an alternative to firm service, with a required reduction in interruptible rates ranging between 20% and 35% below current rates. Of those five bids, three bids indicated that interruptible service was not a viable option and did not specify how they would comply during an interruption event. Enbridge Gas will work with these five customers to determine if their future natural gas requirements can be met with interruptible service despite their bid for new/incremental firm service. The firm demands from these five bids were not included in the updated demand forecast.

30. *EOI results – natural gas conservation:* Customers who submitted an EOI form were asked to confirm whether Enbridge Gas had discussed energy conservation program offerings with them, which all customers confirmed. Customers were also asked to confirm that their EOI bid volumes were inclusive of all future natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternative options. All customers confirmed that to be the case. Customers were also reminded of Enbridge Gas's DSM programs during the in-person customer meeting on March 7, 2023, as well as during the March 23, 2023, virtual customer meeting. /U

31. *ROS results:* There were no requests received from existing contract customers via the ROS to de-contract existing firm or interruptible capacity. In addition, no customers requested to convert existing contracted firm service to interruptible service. /U

32. Since the close of the EOI, Enbridge Gas has continued to engage customers that submitted bids to confirm their interest and negotiate contracts for incremental service. Enbridge Gas is requesting a minimum five-year contract from interested contract rate customers for capacity on the Panhandle System starting in November /U

2024. This practice is consistent with the methodology of contracting for incremental capacity that was used for the PRP and KTRP projects.

33. Contract rate customer demand makes up approximately 94% of the capacity of the proposed Project. As of May 2023, approximately 34% of the contract rate customer demand is underpinned by a firm distribution contract. The commitment letters received in 2021 are no longer being relied upon by Enbridge Gas as they were applicable to the former 2021 EOI process only. Based on the timing of the 2023 EOI process and updated leave to construct application, Enbridge Gas will be executing firm distribution contracts with customers that are requesting service in 2024 and 2025 first, followed by securing customer demands for the future years. /U

34. The contract rate (Rate M/BT4, Rate M/BT5, Rate M/BT7, Rate T-1 and Rate T-2) demand represents approximately 56% of firm demand served by the Panhandle System as of Winter 2022/2023. /U

35. Each customer that requests incremental contract rate service may require an individual service line, main extension, station(s), and/or local distribution reinforcement to bring sufficient natural gas to their site. These costs will be the responsibility of the customer and will be assessed in accordance with E.B.O. 188 guidelines, which may result in the need for the customer to pay a contribution in aid of construction. /U

ii. General Service Growth Forecast

36. Approximately 44% of the firm demand served by the Panhandle System is for general service customers as of winter 2022/2023. Enbridge Gas forecasts that general service customer demand in the Panhandle Market will increase by approximately 4.6% between winter 2022/2023 and 2030/2031. Incremental /U

demands from general service customers make up approximately 6% of the incremental capacity of the proposed Project.

37. The general service growth forecast is informed by Enbridge Gas's internal customer attachment forecast. The customer attachments are converted into a volumetric forecast based on average volume per customer information and geographic location.

38. To ensure continued safe and reliable natural gas service, Enbridge Gas is maintaining enough Panhandle System capacity to serve at least 4 years of general service growth on the system. This practice is due to the amount of time it takes between identifying the need for capacity and commissioning a facility or non-facility project or other IRPA[8].

39. Enbridge Gas is aware of, has reviewed, and is working in conjunction with the municipalities within the Panhandle Market to determine whether the expansion of the Panhandle System impacts their ability to achieve the greenhouse gas ("GHG") emissions reduction goals outlined within their respective Community Energy Plans ("CEPs"). The current CEPs do not include a level of specificity to enable Enbridge Gas to rely upon them as part of its demand forecast for the Panhandle System. This is because of the following:

- Forecasts of measurable reductions in annual and peak-hour natural gas demand/consumption are not available as most CEPs only contain forecasts of annual GHG reductions that are achievable in a variety of

[8] This timeframe includes scope development, design, regulatory process, expropriation, permitting, material procurement, construction, and commissioning, as applicable.

ways and, depending on the initiative, will have a variety of impacts on annual and peak-hour natural gas demand/consumption;[9]

- Details of initiatives/actions intended to be implemented to achieve the reduction targets are not yet available, nor is the associated implementation timing;
- Confirmation of full funding approval for associated programming has not been granted; and
- Confirmation that municipalities have jurisdictional authority to implement the CEP programs and activities has not been determined.

40. Absent the details described above, Enbridge Gas cannot predict the impact that any of these CEPs may have on the timing, annual and peak, and geographic distribution of regional natural gas demands in the future. However, based on Enbridge Gas's working knowledge of the identified municipalities' CEPs, the Company does not anticipate that they will materially influence the demand forecast and the resulting need for capacity on the Panhandle System. This conclusion is further reinforced by the Company's expectation that any capacity created on the Panhandle System could also be relied upon in the future to support transmission and distribution of renewable natural gas and/or hydrogen gas volumes.

iii. Total Panhandle System Growth Forecast

41. Table 2 below summarizes the Design Day demand forecast for the Panhandle System, based on the discussion in the sections above. /U

[9] For example, a programmable thermostat may achieve annual demand reductions, however, would not impact peak demand. Therefore, there would be no impact on the Company's peak demand forecast.

Table 2: Panhandle System Design Day Demand Forecast

	Historical Actuals (TJ/d)			FORECAST (TJ/d)								
	Winter 19/20	Winter 20/21	Winter 21/22	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26	Winter 26/27	Winter 27/28	Winter 28/29	Winter 29/30	Winter 30/31
General Service Firm (Total)	317	308	310	306	308	310	312	314	315	317	319	320
Contract Firm (Total excluding Power Generators)	218	241	256	286	316	329	342	354	367	380	393	406
Power Generators - Firm Contract only	105	106	106	106	106	163	195	195	195	195	195	195
Total System Demand Forecast	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
General Service Firm (Total Incremental Demand)	19	-9	2	-4	2	2	2	2	2	2	2	1
Contract Firm (Incremental excluding Power Generators)	3	23	14	30	30	13	13	13	13	13	13	13
Power Generators - Firm Contract only (incremental)	0	1	0	-1	0	57	32	0	0	0	0	0
Total Incremental Demand Forecast	**22**	**16**	**16**	**26**	**32**	**72**	**47**	**15**	**14**	**14**	**14**	**14**
Total Incremental Demand Forecast (Cumulative)				**26**	**58**	**130**	**177**	**191**	**206**	**220**	**235**	**249**

D. System Growth Benefits

42. The Panhandle System is a critical natural gas pipeline system that supports Enbridge Gas's residential, commercial, and industrial customers west of the Dawn Hub. With continued increasing firm demand forecasted in the Panhandle Market, primarily from greenhouse, automotive and power generation customers in the City of Windsor, Leamington, and Kingsville market areas, the Project will increase long term capacity on the Panhandle System and support the economic well-being of Southwestern Ontario.

43. Ontario's underground natural gas storage facilities (namely the Dawn Hub) provide /U
ratepayers' access to affordable and reliable natural gas supply. This access has become increasingly important due to the increased frequency and severity of extreme weather events experienced across North America in recent years as discussed in Exhibit B, Tab 3, Schedule 1. Affordable energy is critical to the development and prosperity of communities and businesses. Affordable energy promotes and enables growth in the economy, provides savings for residential customers and helps maintain the global competitiveness of Ontario's businesses. Natural gas is the most affordable energy source available to customers. The importance of reliable infrastructure and availability of storage to backstop supply shortfall is paramount to providing firm service with price stability during periods of extreme weather.

44. The Project will directly support job growth, increase property tax revenue for the affected municipalities and tax revenue for the province. Additional details regarding these economic benefits are included in Exhibit E, Tab 1, Schedule 1.

45. The economic benefits natural gas provides are significant. Such benefits include, but are not limited to:
    - residential energy savings enabling more consumer spending at local businesses and across the community (e.g., charitable organizations);
    - energy savings supporting the ability of new businesses to be competitive;
    - enhanced ability to attract new residents and new businesses to the community;
    - enhanced ability for existing businesses to grow and expand;
    - increased housing values and resulting property tax assessments; and
    - municipal energy cost savings in municipal buildings such as arenas and community centres.

46. As indicated by the letters of support received by Enbridge Gas (see Attachment 3 to this Exhibit), the Project has broad support from various parties, including regional municipalities and chambers of commerce. For example:
    The Chatham-Kent Chamber of Commerce said:

> "In order for future growth in Chatham-Kent area to be realized, sufficient natural gas infrastructure will be required and expansion of service is necessary to support current and planned economic developments in the region, particularly in the fast-growing greenhouse, manufacturing sectors and, with that, residential growth of the Chatham-Kent, Windsor and Essex County area. This project is critical for attracting new and aspiring developments by guaranteeing increased access to energy needed for all sectors of the local economy."

Mayor Drew Dilkens, on behalf of the City of Windsor, wrote:

> "… this project represents an investment in the future of our region. Simply put, (the) project ensures that Enbridge Gas continues to meet the ongoing needs of longstanding businesses and industries in Windsor, at a time we are experiencing

exponential growth. This project is also critical for attracting future developments by guaranteeing increased access to energy for all sectors of the local economy."

Sector Specific Benefits:

Greenhouse Sector

47. The growth of the controlled environment agriculture (greenhouse) industry in Southwestern Ontario is vital to the economic prosperity of the region. The greenhouse sector is one area of the agriculture industry that is particularly reliant on natural gas and has a significant impact on the local economy.

48. Natural gas is uniquely suited to the greenhouse sector. It is used to heat greenhouses and to supply the carbon dioxide requirements ("CO_2") of the growing plants. A common practice within the greenhouse sector is to capture the CO_2 that would normally be emitted into the atmosphere upon combustion of natural gas and use it within the greenhouse where it is consumed by the growing plants, resulting in faster growth and increased production.

49. The greenhouse sector does not currently have a viable economic alternative to replace natural gas for heat and CO_2 production.

50. The main alternate fuels used for heating in the greenhouse sector are oil, diesel, and propane. These fuels are not only more expensive than natural gas but also prevent the greenhouse operations from using the CO_2 emissions within the greenhouse because other elements within the exhaust of these fuels will harm the plants. As a result, without natural gas, a more expensive and higher carbon intensive energy source would need to be procured for heat, and an alternative source of CO_2 would also be required to maintain production levels.

51. Over one third of greenhouse production costs are energy related. If natural gas is not available, greenhouse customers will be forced to either rely on a far more expensive alternative, which will threaten their competitiveness, or move their operations to other jurisdictions, such as the United States, where natural gas is available.

52. On average, every acre of greenhouse development: i) creates jobs for five employees, ii) results in significant capital investment of approximately $2,000,000, iii) results in additional spin-off employment, and (iv) annually produces approximately $370,000 worth of produce (2021 farm gate value). /U

53. The greenhouse market in Southwestern Ontario has experienced significant growth, increasing in size from approximately 1,500 acres in 2007 to over 3,500 acres in 2022[10]. This industry provides approximately 14,500 jobs in Southwestern Ontario and supports food processing plants and packagers located in the area. Greenhouse vegetable production is integral to a strong and resilient domestic food supply system and produces nutritious and affordable food for Ontarians.

54. On the 2023 EOI bid forms, customers were requested to provide economic development impacts related to their incremental gas needs. Based on the feedback received through the EOI (75% of bids provided feedback), a total of 6,900 jobs could be created through the greenhouse business growth enabled by the incremental capacity of the proposed Project. In addition, the total direct capital investment into their business operations in Southwestern Ontario indicated by customers on the bid forms exceeded $4.5 billion. /U

[10] https://www.ogvg.com/post/ogvg-applauds-the-province-for-supporting-economic-development-in-southwestern-ontario

55. Letters of support for the Project from the Ontario Greenhouse Vegetable Growers and several large greenhouse customers can be found at Attachment 4 to this Exhibit.

Power Generation Sector

56. The IESO's 2022 Annual Planning Outlook ("APO") electricity demand forecast anticipates a rise in the average growth of electricity demand in Ontario, reaching about 1.9% annually compared to 1.7% in the 2021 forecast.[11] Due to the demand growth, along with nuclear retirements/refurbishments and expiring generation contracts, the IESO is anticipating to experience electricity capacity shortfalls by the mid-2020s. /U

57. On October 6, 2022, Ontario Minister of Energy Todd Smith issued a Minister's Directive to the IESO to procure approximately 4,000 MW of capacity, with up to 1,500 MW of natural-gas fired generation, to ensure the reliable operation of Ontario's electricity system in response to ongoing and growing electricity needs expected in the future.[12] The Minister's Directive noted the IESO's 2021 finding that natural gas-fired generation plays an important role in the near term to avoid rotating blackouts. /U

58. Following the Minister's Directive, the IESO stated that it will seek to secure the new capacity through long-term procurement processes with in-service dates ranging from 2025 to 2027.[13] The IESO also re-iterated that without new natural gas-fired /U

---

[11] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2022/2022-Annual-Planning-Outlook.ashx
[12] https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Directive-from-the-Minister-of-Energy-20221007-resource-eligibility.ashx
[13] Resource Eligibility Interim Report | October 7, 2022, p. 8

generation in the near term, the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid.

59. As per the IESO, the Brighton Beach Generating Station ("BBGS") will play a particularly critical role in meeting localized power generation needs between 2024 /U and 2028.[14] With demand for electricity continuing to grow, it is anticipated that BBGS will continue to play a significant role in maintaining energy reliability in the region and will serve increased peak period electricity demand growth in the Southwest Region beyond 2028. Additionally, the IESO's May 16, 2023 Resource Adequacy Update stated that the IESO has finalized a 10-year agreement for the continued operation of the BBGS facility, including a 42.5 MW efficiency upgrade for the facility.[15]

60. In January 2023, Windsor City Council voted to support an energy proposal from Capital Power to pursue an expansion at its existing East Windsor Cogeneration /U Centre location related to the above mentioned IESO procurement.[16] The IESO's May 16, 2023 Resource Adequacy Update highlighted that the East Windsor Cogeneration Centre location was awarded an incremental 100 MW contract.[17]

61. It is Enbridge Gas's understanding that these near-term and longer-term needs /U have driven requests for incremental firm service from these customers, and the

[14] IESO Annual Planning Outlook, December 2021, p. 57, https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/Demand-Forecast-Module.ashx
[15] https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-adequacy/ieso-resource-adequacy-update-May2023.ashx
[16] https://windsorstar.com/news/local-news/capital-powers-natural-gas-turbine-expansion-in-windsor-approved
[17] https://www.ieso.ca/-/media/Files/IESO/Document-Library/resource-adequacy/ieso-resource-adequacy-update-May2023.ashx; https://ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/ELT1-RFP-Selected-Proponents.ashx

incremental firm service needs from these customers are reflected in the Panhandle System's demand forecast.

62. A letter of support for the Project from Atura can be found at Attachment 5 to this Exhibit. A letter of support for the Project from Capital Power can be found at Attachment 7 to this Exhibit. /U

Automotive Sector in Southwestern Ontario

63. The automotive sector also has significant natural gas demands. The City of Windsor is home to major automotive manufacturers as well as Tier 1 and Tier 2 automotive suppliers. This industry employs thousands of people in the Panhandle Market. Natural gas is relied upon through the automotive manufacturing process, including for paint baking, paint shop humidification, and melting metal for auto parts. Moreover, natural gas cannot be easily substituted with other energy sources for carrying out these processes. Phase 2 of Ontario's plan, *Driving Prosperity: The Future of Ontario's Automotive Sector* aims to support the attraction of large-scale electric vehicle and electric battery production, to anchor an advanced electric battery supply chain in the Province[18].

64. On March 23, 2022, the multinational automotive manufacturing company, Stellantis, and the battery manufacturer, LGES, announced that they had entered into a binding joint-venture agreement to establish the first large scale EV battery manufacturing facility in Windsor, Ontario, through an entity to be known as /U

[18] https://files.ontario.ca/medjct-driving-prosperity-ontario-automotive-plan-phase-2-en-2021-11-23.pdf

NextStar.[19] Natural gas plays a critical role in meeting the energy needs of the EV, EV battery and EV battery component manufacturing sector.

65. Since the NextStar EV battery plant was announced, Enbridge Gas has been responding to multiple confidential inquiries from EV battery component manufacturers that have expressed interest in the Windsor-Essex region and the availability of natural gas capacity. Demands for incremental natural gas capacity are expected in this region as participants in the EV component supply chain desire to situate themselves in close proximity to the new NextStar production facility. Due to the preliminary nature of these discussions, these demands have not been included in the demand forecast for the Project.

66. A letter of support for the Project from Stellantis can be found at Attachment 6 to this Exhibit. As discussed in paragraph 18 above, Enbridge Gas has since finalized a contract with NextStar for service commencing in September 2023, using a portion of the remaining Panhandle System existing capacity. However, the broader system benefits of the proposed Project outlined by Stellantis in Attachment 6 including access to reliable and affordable natural gas supply to support future investments and developments in the local economy remain relevant. /U

E. Project Timing and Enbridge Gas Growth Plans

67. The Project has previously been identified within Enbridge Gas's Asset Management Plan ("AMP"), as filed with the OEB. More particularly, as part of the Company's 2022 Rates (Phase 2) proceeding, Enbridge Gas filed an AMP Addendum which identified the proposed Project as a requirement to meet the growing Design Day demand of the Panhandle System:

[19] https://www.stellantis.com/en/news/press-releases/2022/march/stellantis-and-lg-energy-solution-to-invest-over-5-billion-cad-in-joint-venture-for-first-large-scale-lithium-Ion-battery-production-plant-in-canada

> "The Panhandle Regional Expansion Project (PREP) is required to provide reliable, secure, economic natural gas supply to meet the growing design day demand of the EGI Panhandle Transmission System which serves in-franchise markets (including residential, commercial and industrial customers). As a result of a non-binding Expression of Interest (EOI) conducted in February 2021, EGI is forecasting firm transportation growth driven by general service growth, greenhouse market demand in Leamington / Kingsville / Chatham-Kent and industrial demand in Windsor requiring incremental facilities as early as winter 2023-24. Alternatives are being evaluated at varying levels of detail depending upon project feasibility including engineering, cost, construction feasibility, capacity and reliability. Through this process, EGI will identify the most efficient project to provide the Panhandle Transmission System with reliable supply and adequate capacity for both design day conditions and operational conditions. As part of the project plan, EGI will complete a supply-side IRP assessment in addition to a binding reverse open season. In this way, EGI will minimize the facilities required to serve incremental demand while optimizing any unwanted existing capacity."[20]

68. Exhibit D, Tab 1, Schedule 1 describes the overall Project and construction schedule. Construction of the NPS 36 pipeline and ancillary measurement station facilities is planned to commence in Q1 2024 and to be placed into service by November 2024, and construction of the pressure regulation and measurement facilities within the Dawn Yard is planned to commence in Q2 2025 and to be placed into service by November 2025. The construction schedule for both portions of the project takes advantage of the drier summer months, thereby minimizing the impact of construction on agricultural lands and other features such as watercourses. /U

69. Enbridge Gas has taken extra steps at the front end of the Project to begin early negotiations with landowners and other impacted stakeholders, including municipalities and Indigenous communities, to minimize the potential for requiring land expropriation.

70. Enbridge Gas has also identified the potential need for a second phase of transmission expansion to meet the demands that are forecasted over the next 20

---

[20] EB-2021-0148, Exhibit B, Tab 2, Schedule 3, P. 8

years. This second phase has been identified within the Enbridge Gas 2021-2025 AMP with a forecasted 2029 in-service date as shown below.

> "Panhandle Transmission System Reinforcement - The Panhandle System expansion is driven by in-franchise growth in Chatham-Kent, Windsor-Essex and surrounding areas, including the fast-growing greenhouse market in the Leamington/Kingsville area. Based on the current forecast for in franchise general service and contract growth in the Panhandle Transmission System market, EGI has determined that the next Panhandle facilities for expansion will need to be in place for the 2029 winter season (construction beginning in 2029)." [21]

/U

F. Conclusion

71. Enbridge Gas is forecasting continued demand growth from commercial, industrial, and residential customers located in the areas west of Dawn, with concentration in the Municipalities of Windsor, Leamington, and Kingsville. This demand growth is primarily driven by the greenhouse, power generation, and automotive sectors in the region.

72. As a result of the increased forecast of demand growth, there is a need for capacity on the Panhandle System to meet the forecasted firm system demands by November 1, 2024.

73. If this natural gas capacity on the Panhandle System is not available by such day, there is a risk that businesses will delay or cancel plans to expand or may establish their operations in different jurisdictions where reliable, affordable energy is available.

---

[21] EB-2021-0181, Exhibit C, Tab 2, Schedule 1, P. 88

PANHANDLE SYSTEM DESIGN AND NETWORK ANALYSIS

1. The purpose of this section of evidence is to: i) provide an overview of the current and future design and operation of Enbridge Gas's Panhandle System, and ii) to describe the network analysis methodology and its results which demonstrate the existing Panhandle System will be unable to meet the demands as detailed in Exhibit B, Tab 1, Schedule 1, by the winter of 2024/2025. /U

2. This Exhibit includes the following sections:
   A. Panhandle System Overview
   B. Panhandle System Design
   C. Panhandle System Supply and Demand
   D. Panhandle System Network Analysis
   E. Conclusion

A. Panhandle System Overview

3. The Panhandle System is the transmission system that supplies natural gas to the Panhandle Market. The Panhandle System also provides C1 Rate transportation services from Michigan through the Ojibway Valve Site ("Ojibway") to the Dawn Compressor Station ("Dawn" or "Dawn Hub"). Figure 1 below illustrates the Panhandle System and the market areas it supplies.

4. The Panhandle System is critical to providing safe, reliable, and affordable natural gas to Enbridge Gas's in-franchise residential, commercial, and industrial customers in the Panhandle Market. A reliable, cost competitive energy supply is fundamental to economic well-being and growth in Ontario. As detailed in Exhibit B, Tab 1, Schedule 1, the forecast rate of growth in the Panhandle Market has surpassed

Table 2: Panhandle System Demands by Service Type for Winter 2022/2023 /U

Service Type	Demands (TJ/d)
General Service (firm)	306
Contract Rate (firm)	392
Contract Rate (Interruptible)	87
Total	785

26. Enbridge Gas continues to offer customers the ability to turn back firm service and select interruptible service. This offering, if accepted, would reduce Design Day firm demands. As described in Exhibit B, Tab 1, Schedule 1, to date there has been no interest from customers to turn back firm service.

D. Panhandle System Network Analysis

27. The Panhandle System capacity for Winter 2022/2023 is 737 TJ/day[11]. The forecasted firm demand on the Panhandle System for Winter 2022/2023 is 698 TJ/day. A forecast of the Panhandle System capacity, Design Day demand, and shortfall is detailed in Table 3 below. /U

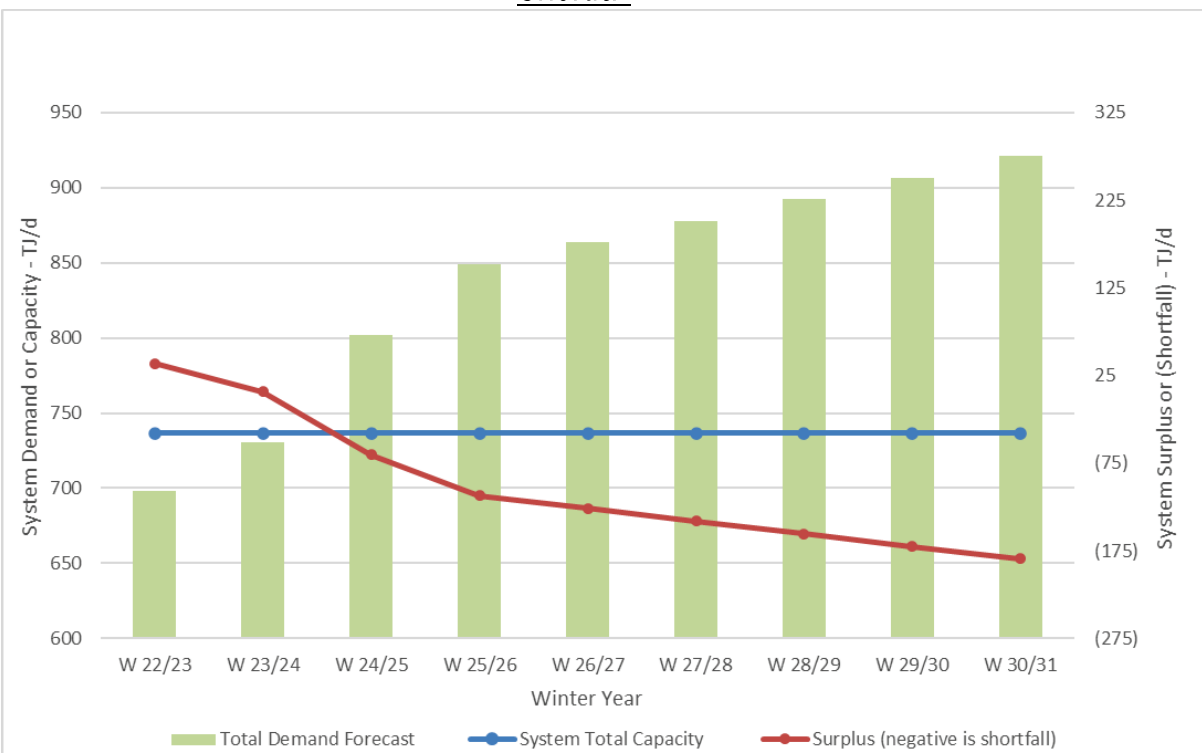
Table 3: Panhandle System Capacity, Design Day Demand, and Shortfall /U

	Historical Actuals			FORECAST								
	Winter 19/20	Winter 20/21	Winter 21/22	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26	Winter 26/27	Winter 27/28	Winter 28/29	Winter 29/30	Winter 30/31
Panhandle System Capacity (TJ/d)	**725**	**725**	**713**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**
Design Day Demand Forecast (TJ/d)	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
Surplus (shortfall is negative) (TJ/d)	84	69	41	38	6	(66)	(112)	(127)	(141)	(156)	(170)	(184)

[11] The existing system capacity has increased since the previous forecast due to differences in the actual location of growth and changes in the energy content of the gas.

28. In Winter 2023/2024, the Design Day demand is expected to increase to 730 TJ/d and is forecast to further increase to a Design Day demand of 802 TJ/d in Winter 2024/2025. This demand exceeds the current system capacity of 737 TJ/d, resulting in a shortfall of 66 TJ/day beginning in Winter 2024/2025. Figure 3 below shows a graphical representation of the forecasted Panhandle System capacity, Design Day demand, and shortfall. /U

Figure 3: Graph of the Forecast Panhandle System Capacity, Design Day Demand and Shortfall /U



29. Design Day demands are based on the forecast detailed in Exhibit B, Tab 1, Schedule 1

ONTARIO ENERGY BOARD

FILE NO.: **EB-2022-0157** **Enbridge Gas Inc.**

VOLUME: **Technical Conference**

DATE: **October 6, 2022**

We have done a 10-year outlook of growth. However, we're seeking at this point only approval for the facilities to serve the five year outlook in growth, and that is what you are asking.

As you know, the initial part of this there is some growth related to Brighton Beach and some other special contracts and then after that, we pattern this after our understanding of that expressed interest, but also limited by the market's capacity to be able to build infrastructure, to build new greenhouses is -- has a capacity, if you will.

MR. QUINN: Okay. So as opposed to reiterating what was said before, Ian, I will summarize again. This is an extrapolation of a trend to 2030. Correct?

MR. MacPHERSON: This trend, this is backed by the expression of interest bids that the company received in our process in 2021. So this is not -- this is not -- I mean we have done, I guess you know, adjustments but we have real stated interest that is reflected in this forecast.

MR. QUINN: It is reflected in the forecast. But do you have contracts that you add up all of the contracts that are between your commitment letters and all of the rest of the more firm contracts, do you have contractual -- do you have letters of demand from customers that would total to 980 as of 2030? It is a simple yes or no.

MR. MacPHERSON: So maybe I could ask Matt, Mr. Ciupka, to respond between the expressed interest and what the current market capacity. Could you just, please, state what that total would be?

MR. CIUPKA: Yes. Matt Ciupka, Enbridge Gas. So from greenhouse customers through the expression of interest forecast period in that process, we have the energy equivalent to roughly 4600 acres of greenhouse expansion between the period of 2023-24 to 2032-33. And so that -- all of that expressed interest has been included in the long term demand forecast, but again we are proposing to build facilities to support the immediate five year forecast for which we have great certainty from customers through the customer commitments executed to date.

MR. QUINN: I would like to get back to that five years and I will in a moment. But I asked the question about 980 TJs. That is what your graph shows.

I can't seem to get anybody to answer the question: Is this a summation of all of your letters of commitment and more firm contracts or not? Or is this an -- you talked about market area of growth and acreage that could be under glass. I get that. But that is -- frankly, that is an extrapolation if you haven't had a customer say and I need an extra ten TJs in 2030.

MS. THOMPSON: Thompson, Enbridge Gas. I think a good reference would be Exhibit B, tab 1, schedule 1, table 1. That table is actually a reflection of our historical actuals and the demand forecast out to 2030-31, which is a reflection of the data that is on that graph.

So the data...

MR. QUINN: But that data, Ms. Thompson, is that data based upon actual letters of commitment or more from contracts?

MR. MacPHERSON: Ian MacPherson, Enbridge. The answer again is no. Out to 2031 as we stated a few times, we have letters of commitment which are very high, actually, very high, in relation to the 203 TJs which we're seeking approval now to build. Not seeking approval to build the total forecast capacity of the EOI.

So that is what we're comparing against. And that is what would be normally would be occurring here. Like in the way the market evolves with growth, people -- customers aren't signing contracts for things years in the future. That is just not how the market evolves in the distribution market.

I am not sure if I am answering what you are saying, but we would not expect that to be clear, in any event that we would be in a position to have every, every TJ of capacity built.

We're here discussing the demand forecast and its veracity against that market interest, and that is what we are focussed on explaining here today.

MR. QUINN: For the purpose of moving on, I am going to say it myself, and you will tell me if it is right or wrong. You do not have letters of commitment and other contracts that would total 980 TJs by 2031; correct?

MR. MacPHERSON: Based on my understanding of what you are saying, the answer is no. But I would qualify that to say, nor we would be expecting to and nor does that necessarily align with our proposal here today and our request for approval.

MR. QUINN: This would go a lot more easily, Mr. MacPherson, if you would answer the question that I am asking.

I understand your focus, there is demand there. I get it. The next five years, so let's move to that. But showing a graph and showing a trend that is completely constant for five years lends somebody to believe -- some understanding to say that has to be an extrapolation, an averaging of smoothing. I was trying to figure out if there are contracts underpinning it.

But I am going to move backwards to the five-year time frame you are talking about.

In that five-year time frame, and I think it is actually somewhere else. If you can tell me what the reference is I can move down. Actually, if we can go to Staff 4. That is one reference that might help us here.

What I am trying to do is differentiate these customers that have signed letters of commitment and this is showing interruptible. I am at risk of mixing this thing up, so I will stay with the letters of commitment first.

Do you have somewhere else on the record the amount customers have, quote-unquote -- that are letters of commitment versus firm contracts? I thought I saw is somewhere else in the record. I couldn't find it this morning. If anyone has that reference then we could move on to the IT part of it.

MR. CIUPKA: Mat Ciupka, Enbridge Gas.

MR. QUINN: Yes.

MR. CIUPKA: If you pull up the response to IR Staff 3.

MR. QUINN: Staff 3?

MR. CIUPKA: There was a table provided that shows the breakdown of distribution contracts and executed letters of indemnity and commitment letters.

MR. QUINN: Just so we can move on with comfort that I am getting the answer that I was seeking. Yes, that is where it is. I'm sorry. That is exactly it, and I can use that going forward. So that is sufficient for now on these letters of commitment versus executed distribution contracts, is the way you put it in here. So thank you for that.

MR. MILLAR: Dwayne, we are at 11:15. Is this a good spot for a break?

MR. QUINN: I was hoping to get through the demand side, Michael.

MR. MILLAR: If you can do it in five minutes.

MR. QUINN: I will try to do it in five minutes. If we start spinning our wheels again I will defer to after the break.

MR. MILLAR: Go ahead.

MR. QUINN: Moving to the next one, Ms. Allman, thank you, Staff 4.

MR. SZYMANSKI: I could tell you now. It is obtained from the Natural Resources Canada website for the location of Windsor.

MR. ELSON: For both of those, if you could undertake to provide us a link because otherwise we will be running around on the Internet to find out which NR can data you are referring to, that would be appreciated.

MR. SZYMANSKI: We can do that.

MR. ELSON: Thank you.

MR. PARKES: JT1.32.

UNDERTAKING NO. JT1.32: TO PROVIDE THE SOURCE FOR THE NRCAN PRICING FOR HEATING OIL AND PROPANE

MR. ELSON: Thank you. If I could turn to Pollution Probe 5, page 2. And could you agree to add a column indicating for each of these whether it is a commitment letter, indemnity letter or contract?

MR. CIUPKA: Matt Ciupka, Enbridge Gas. We can take it away to split the letters of indemnity and commitment letters from the number provided at the bottom of the table.

MR. ELSON: Okay. That would be a start.

MR. PARKES: That is JT1.33.

UNDERTAKING NO. JT1.33: RE THE TABLE AT POLLUTION PROBE 5, PAGE 2, TO ADD A COLUMN INDICATING WHETHER THERE IS A COMMITMENT LETTER OR AN INDEMNITY LETTER.

MR. ELSON: And I take it the numbers that actually have dates attached to them, the first four, are you able to just tell me off-the-cuff whether those are commitment letters, letters of indemnity, or distribution contracts?

MR. CIUPKA: Matt Ciupka, Enbridge Gas. Those are distribution contracts.

MR. ELSON: Okay. And you said in your presentation that 80 percent of the capacity is committed.

What was the meaning of that? And how does that correspond to the figure at the bottom of total commitments of 167.3?

MR. CIUPKA: Matt Ciupka, Enbridge Gas. So the 167.3 TJs a day at the bottom of the table compared to the total overall capacity of the proposed facilities of 203 TJs a day.

MR. ELSON: Got it. And so the total commitments includes commitment letters?

MR. CIUPKA: Correct.

MR. ELSON: What is the penalty in the case of a letter of indemnity versus a distribution contract if a customer backs out?

MR. CIUPKA: Matt Ciupka, Enbridge Gas. So for a letter of indemnity, there would be a set amount in the contract based on what materials and what costs Enbridge would be seeking to recover, in case the customer decided not to proceed with the distribution contract.

And with the distribution contract, there would be costs associated with breaking the distribution contract, per the terms and condition of that contract.

And I would refer back to the attachment for PP 5 that shows the contract templates to give an indication of what those costs would look like.

MR. ELSON: And what is the order of magnitude between a letter of indemnity versus a distribution contract penalty? Are we talking the contract penalty is going to be multiple times higher?

MR. CIUPKA: Matt Ciupka, Enbridge. It would really depend on the specific customer, the requirements they're requesting, any facilities that are required to provide the service to their contract, in addition to any facilities required from this project. So it is very much customer-specific.

MR. ELSON: Now, that is fair. Is there anything you can say on a generalized level? Is there a significant difference in let's say the majority, or often a significant difference? I am just trying to get a sense of how much greater the penalty is once you have a distribution contract.

I understand like everything it varies, but can you speak to that directionally or some sort of average?

MR. CIUPKA: I cannot. Again it is very dependent on the contract, the customer, the volume of gas they're requesting, their location, et cetera.

MR. ELSON: Okay. Well, this might be a good time for me to wrap up. I may be largely through my questions, but I can confirm that tomorrow.

MR. PARKES: Okay. Thanks, Mr. Elson. That makes sense. My understanding is that we will start with Mr. Brophy from Pollution Probe at 9:30 and you will resume

ENBRIDGE GAS INC.

Undertaking Response to ED

Re the table at Pollution Probe 5, page 2, to add a column indicating whether there is a commitment letter or an indemnity letter.

Response:

Please see Table 1 below. To preserve confidentiality of customer-specific commercially sensitive information that could divulge the nature and timing of investment decisions, Enbridge Gas is seeking confidential treatment of redacted content in Table 1.

Table 1

Customer	TJ/day	Contract Start Date	Contract End Date	Commitment Type
[redacted]	1.4	1-Nov-23	31-Oct-28	Distribution Contract
	2.4	1-Nov-23	31-Oct-40	Distribution Contract
	1.6	1-Nov-23	31-Oct-28	Distribution Contract
	57.7	16-Jul-24	15-Jul-29	Distribution Contract
	3.1	N/A	N/A	Letter of Indemnity
	19.0	N/A	N/A	Letter of Indemnity
	1.1	N/A	N/A	Commitment Letter
	2.3	N/A	N/A	Commitment Letter
	2.1	N/A	N/A	Commitment Letter
	2.8	N/A	N/A	Commitment Letter
	0.8	N/A	N/A	Commitment Letter
	2.8	N/A	N/A	Commitment Letter
	2.8	N/A	N/A	Commitment Letter
	1.2	N/A	N/A	Commitment Letter
	5.7	N/A	N/A	Commitment Letter
	1.0	N/A	N/A	Commitment Letter
	0.9	N/A	N/A	Commitment Letter
	2.4	N/A	N/A	Commitment Letter
	3.5	N/A	N/A	Commitment Letter
	3.5	N/A	N/A	Commitment Letter
	3.2	N/A	N/A	Commitment Letter
	11.3	N/A	N/A	Commitment Letter
	1.8	N/A	N/A	Commitment Letter
	1.8	N/A	N/A	Commitment Letter
	1.8	N/A	N/A	Commitment Letter
	10.6	N/A	N/A	Commitment Letter
	0.8	N/A	N/A	Commitment Letter
	1.4	N/A	N/A	Commitment Letter
	1.0	N/A	N/A	Commitment Letter
	1.7	N/A	N/A	Commitment Letter
	0.4	N/A	N/A	Commitment Letter
	1.4	N/A	N/A	Commitment Letter
	6.8	N/A	N/A	Commitment Letter
	3.3	N/A	N/A	Commitment Letter
	0.1	N/A	N/A	Commitment Letter
	1.7	N/A	N/A	Commitment Letter

Distribution Contract Total (TJ/day)	63.1
Letter of Indemnity Total (TJ/day)	22.1
Commitment Letter Total (TJ/day)	82.2
Total Commitments (TJ/day)	**167.3**

ENBRIDGE GAS INC.

Undertaking Response to PP

Re table 1 in IR PP 5, on a best-efforts basis, recognizing they are estimated dates, to identify any corresponding dates to the obligations that are identified in this table.

Response(s):

Please see Table 1 below. To preserve confidentiality of customer-specific commercially sensitive information that could divulge the nature and timing of investment decisions, Enbridge Gas is seeking confidential treatment of redacted content in Table 1.

It is important to note that distribution contracts do not expire. They are evergreen (i.e., automatically renew annually) unless a customer provides notice to Enbridge Gas that they wish to terminate the contract prior to the end of the “Initial Term” of the contract, or prior to the annual renewal date of the contract. Enbridge Gas has no such basis (i.e., customer notice) for which to assume that existing distribution contracts will not be renewed.

Table 1

Customer	TJ/day	Contract Start Date	Contract End Date	Commitment Type	Requested In-service Date (LOI/CL)	Expiry Date (LOI/CL)*
[redacted]	1.4	1-Nov-23	31-Oct-28	Distribution Contract	n/a	n/a
[redacted]	2.4	1-Nov-23	31-Oct-40	Distribution Contract	n/a	n/a
[redacted]	1.6	1-Nov-23	31-Oct-28	Distribution Contract	n/a	n/a
[redacted]	57.7	16-Jul-24	15-Jul-29	Distribution Contract	n/a	n/a
[redacted]	3.1	N/A	N/A	Letter of Indemnity	1-Aug-23	n/a
[redacted]	19.0	N/A	N/A	Letter of Indemnity	1-Sep-23	n/a
[redacted]	1.1	N/A	N/A	Commitment Letter	1-Jan-23	31-Dec-22
[redacted]	2.3	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	2.1	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	2.8	N/A	N/A	Commitment Letter	1-Nov-23	1-Nov-22
[redacted]	0.8	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	2.8	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	2.8	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	1.2	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	5.7	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	1.0	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	0.9	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	2.4	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	3.5	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	3.5	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-23
[redacted]	3.2	N/A	N/A	Commitment Letter	1-Nov-23	31-Oct-22
[redacted]	11.3	N/A	N/A	Commitment Letter	1-Dec-23	30-Nov-23
[redacted]	1.8	N/A	N/A	Commitment Letter	1-Jan-24	1-Jan-23
[redacted]	1.8	N/A	N/A	Commitment Letter	1-Jan-24	1-Jan-23
[redacted]	1.8	N/A	N/A	Commitment Letter	1-Jan-24	1-Jan-23
[redacted]	10.6	N/A	N/A	Commitment Letter	1-Apr-24	1-Oct-23
[redacted]	0.8	N/A	N/A	Commitment Letter	1-Aug-24	31-Jul-23
[redacted]	1.4	N/A	N/A	Commitment Letter	1-Aug-24	31-Jul-23
[redacted]	1.0	N/A	N/A	Commitment Letter	1-Aug-24	31-Jul-23
[redacted]	1.7	N/A	N/A	Commitment Letter	1-Nov-24	31-Oct-23
[redacted]	0.4	N/A	N/A	Commitment Letter	1-Nov-24	31-Oct-24
[redacted]	1.4	N/A	N/A	Commitment Letter	1-Nov-24	31-Oct-24
[redacted]	6.8	N/A	N/A	Commitment Letter	1-Sep-25	31-Aug-24
[redacted]	3.3	N/A	N/A	Commitment Letter	1-Nov-25	31-Oct-25
[redacted]	0.1	N/A	N/A	Commitment Letter	1-Nov-26	31-Oct-26
[redacted]	1.7	N/A	N/A	Commitment Letter	1-Nov-27	31-Oct-27

Distribution Contract Total (TJ/day)	63.1
Letter of Indemnity Total (TJ/day)	22.1
Commitment Letter Total (TJ/day)	82.2
Total Commitments (TJ/day)	**167.3**

NOTE:
*If a CL expires, or if the estimated in-service date cannot be met, the CL is expected to be renewed with the customer with a revised in-service date.

ENBRIDGE GAS INC.

Undertaking Response to IGUA

Enbridge to explain why it did not make a proposal to enable seeking of a contribution for the capacity sought.

Response:

The proposed Project is a transmission project (please also see the response at Exhibit JT1.2 for Enbridge Gas's definitions of transmission and distribution pipelines) that will increase capacity on the Panhandle System to meet forecast demand within a large area of benefit.[1] While the demand underpinning the need for the proposed Project is informed by customer demand throughout the area of benefit, there will be no customers directly connecting to the proposed Project (Panhandle Loop and Leamington Interconnect).

Distribution projects, in comparison, generally provide customer premises with direct access to natural gas. In the case of distribution projects, it can be appropriate to seek a financial contribution from customers whose premises will be directly benefiting from the project. These financial contributions can minimize cross-subsidisation by customers who will not benefit from the distribution facilities.

It is not appropriate to seek a financial contribution from specific customers for the proposed transmission Project because, as a transmission system, the Panhandle System transports natural gas for the benefit of all customers within the Panhandle Market – rather than individual or specific customers. Once in service, the proposed Project will serve all customers, whether or not they participated in the expression of interest. The proposed Project addresses system bottlenecks, which once relieved, will improve the reliability of service for existing customers, and will allow for growth from existing and new customers.

It should be noted that the Company's approach is consistent with previous Enbridge Gas applications to the OEB seeking leave to construct, including the Kingsville Transmission Reinforcement Project ("KTRP") (EB-2018-0013). Within the OEB's Decision in the KTRP leave to construct proceeding, the OEB found that the Company "appropriately followed the OEB's E.B.O. 134 test for transmission projects" and confirmed that "currently there is no mechanism to have these parties make a contribution to the costs."[2]

---

[1] Exhibit B, Tab 1, Schedule 1, p. 5, Figure 1
[2] EB-2018-0013, OEB Decision and Order (September 20, 2018), pp. 5-6

The Company's approach is also in alignment with the OEB's Decision (less than two years ago) on Enbridge Gas's Application for Approval of a System Expansion Surcharge ("SES"), a Temporary Connection Surcharge ("TCS"), and an Hourly Allocation Factor ("HAF"), specifically:

> "The OEB approves the use of HAF for projects that are primarily distribution and if there is a minor component of transmission then the OEB would still accept the use of HAF. For exclusively transmission projects, the OEB has not agreed to the application of HAF."[3]

[3] EB-2020-0094, OEB Decision and Order (November 5, 2020), p. 20

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, page 7, paragraph 20 and page 9, paragraph 26

Preamble:

The Project's incremental capacity is estimated to be 203 TJ/d. Approximately 98% of this capacity is expected to meet the demand of contract rate customers. Enbridge Gas asserted that, at the time of filing the application, 80% of the contract rate customer demand is subject to commitments by those customers. Binding commitments represent 159 TJ/d, including approximately 62 TJ/d of executed firm distribution contracts. Enbridge Gas noted that 100% of the 2023/2024 forecasted incremental demand on the Panhandle System is secured with binding customer commitments.

Question:

a) Please clarify what the "binding commitments" that are not firm distribution contracts entail.
b) Please provide any updates to the contract rate customers commitments or the executed contracts since filing the application.

Response

a) A Commitment Letter ("CL") and/or a Letter of Indemnity ("LOI") are "binding commitments" that are not firm contracts, and can be utilized prior to the execution of a distribution contract. These binding commitments demonstrate a customer's commitment to the capacity they have expressed interest in or have formally requested from Enbridge Gas.

The use of CLs is a standard practice for Enbridge Gas and they have been used previously for the Chatham-Kent Rural Pipeline project (EB-

2018-0013). They are intended to provide further customer commitment to the requests for capacity received through an EOI process, prior to a customer executing an LOI or distribution contract.

There are no financial assurances required to execute a CL.

The use of LOIs is also standard practice for Enbridge Gas. They are commonly used prior to the execution of a distribution contract. Their usage allows Enbridge Gas to order long-lead time items and/or initiate project activities prior to the finalization of a distribution contract. Financial assurances are required for LOIs.

Refer to response to Exhibit I.PP.5 part b) for the LOI and CL templates.

b) Table 1 below outlines the customer commitments to the Project as at the June 10, 2022 LTC application filing date, as well as the updated commitment numbers as at September 22, 2022, organized by commitment type.

Table 1

	TJ/d	
PREP Capacity Commitments	**As at Jun 10, 2022 (LTC filing)**	**As at Sep 22, 2022 (IR Responses)**
Executed Distribution Contracts	62	63
Executed Letters of Indemnity / Commitment Letters	97	104
Total PREP Capacity Commitments	**159**	**167**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

INTERROGATORY

Reference:

IESO Pathways to Decarbonization Report - Pathways to Decarbonization (ieso.ca)

Question(s):

IESO analysis suggests that natural gas capacity can be reduced to 8,000 MW from the current 10,000 MW by 2035 and completely phased out in the 2050 scenario.

a) Please provide Enbridge’s assumptions for how long each current or proposed gas fired generating station served (directly or indirectly) by the Panhandle system will be in service.

b) Please confirm the amortization period for the proposed pipeline.

c) If the proposed amortization period for the proposed pipeline is greater than 25 years (i.e. by 2050), please explain how recovery of the unamortized portion of the pipeline will be recovered if no gas fired generating stations remain on the Panhandle system.

Response:

a) Both of the gas-fired generation customers that bid into the EOI received contract extensions of 10 years or more from the IESO. Although the draft Clean Electricity Regulations released by the government of Canada notes that the new regulations will come into effect in 2035, at this time, Enbridge Gas has no reason to believe that these power producers will not remain connected to the Panhandle System after their current contract, as these gas-fired generators can remain operational in the future by pursuing energy transition solutions that allow them to meet net zero goals. In addition, the draft Clean Electricity Regulations released by the government of Canada also makes reference to allowing natural gas facilities to operate outside of the performance standard for short periods of time over the course of the year; therefore, these gas plants could be kept as a backup to address periods of high demand or to balance variable production from renewables.

b) The current OEB-approved depreciation rate for transmission pipelines in the Union Rate Zone assumes an average service life of 55 years.

c) The impacts of the energy transition remain uncertain. As noted in part a), Enbridge Gas has no reason to expect, at this point, that power generators will not be connected to the Panhandle System for the duration of the asset's average service life. Further, changes over the next 25 years could result in other existing or new customers utilizing the system. Enbridge Gas expects that it will be able to recover the costs of prudently invested capital. If changes in future utilization indicate the need for a shorter average service life, the Company would leverage regulatory processes and mechanisms (e.g. accelerated depreciation) to maintain the regulatory compact.

Enbridge Gas is not seeking cost recovery of the Project as part of this application.[1]

[1] Exhibit A, Tab 3, Schedule 1, para. 13.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, page 7, paragraph 20 and page 9, paragraph 26

Preamble:

The Project's incremental capacity is estimated to be 203 TJ/d. Approximately 98% of this capacity is expected to meet the demand of contract rate customers. Enbridge Gas asserted that, at the time of filing the application, 80% of the contract rate customer demand is subject to commitments by those customers. Binding commitments represent 159 TJ/d, including approximately 62 TJ/d of executed firm distribution contracts. Enbridge Gas noted that 100% of the 2023/2024 forecasted incremental demand on the Panhandle System is secured with binding customer commitments.

Question:

a) Please clarify what the "binding commitments" that are not firm distribution contracts entail.
b) Please provide any updates to the contract rate customers commitments or the executed contracts since filing the application.

Response

a) A Commitment Letter ("CL") and/or a Letter of Indemnity ("LOI") are "binding commitments" that are not firm contracts, and can be utilized prior to the execution of a distribution contract. These binding commitments demonstrate a customer's commitment to the capacity they have expressed interest in or have formally requested from Enbridge Gas.

The use of CLs is a standard practice for Enbridge Gas and they have been used previously for the Chatham-Kent Rural Pipeline project (EB-

2018-0013). They are intended to provide further customer commitment to the requests for capacity received through an EOI process, prior to a customer executing an LOI or distribution contract.

There are no financial assurances required to execute a CL.

The use of LOIs is also standard practice for Enbridge Gas. They are commonly used prior to the execution of a distribution contract. Their usage allows Enbridge Gas to order long-lead time items and/or initiate project activities prior to the finalization of a distribution contract. Financial assurances are required for LOIs.

Refer to response to Exhibit I.PP.5 part b) for the LOI and CL templates.

b) Table 1 below outlines the customer commitments to the Project as at the June 10, 2022 LTC application filing date, as well as the updated commitment numbers as at September 22, 2022, organized by commitment type.

Table 1

	TJ/d	
PREP Capacity Commitments	**As at Jun 10, 2022 (LTC filing)**	**As at Sep 22, 2022 (IR Responses)**
Executed Distribution Contracts	62	63
Executed Letters of Indemnity / Commitment Letters	97	104
Total PREP Capacity Commitments	**159**	**167**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"The Project as proposed is designed to reliably serve increased demands for firm service in the Panhandle Market, including, in particular, incremental demands from the greenhouse, automotive, and power generation sectors." [A/2/1 Page 2]

Question:

a) What is the current peak demand (GJ) for the Panhandle system and what will be the peak demand capacity if the project is approved and completed.
b) Please provide a copy of all firm contracts and firm commitments from greenhouse, automotive, and power generation sectors customers that drive the incremental peak demand identified.
c) Please provide a table showing each customer incremental natural gas peak demand that would be supplied by the proposed pipeline and include columns indicating the start and end date for each firm contractual commitment related to those peak demand commitments.
d) Please identify any additional peak demand capacity that the proposed project would provide in excess of the contracted demand identified.
e) Please confirm that the Panhandle system has the capacity to provide for ex-franchise delivery (e.g. export) and what the capacity is available for ex-franchise deliver.

Response

a) The current Panhandle System peak day demand is 671,893 GJ/d and the system capacity is 713,346 GJ/day. The system capacity will be 916,313 GJ/day once the Project is placed into service.

b) Please see the contract and commitment templates set out in Attachment 1 of this response, which are representative of all executed commitments from customers. Please see the response to part c) below for customer-specific bid details.

c) Please see Table 1 below for the firm customer commitments received to date. To preserve confidentiality of customer-specific commercially sensitive information that could divulge the nature and timing of investment decisions, customer names have been redacted.

Table 1

Customer	TJ/day	Start Date[1]	End Date[2,3]
[redacted]	57.7	16-Jul-24	15-Jul-29
[redacted]	1.4	1-Nov-23	31-Oct-28
[redacted]	2.4	1-Nov-23	31-Oct-40
[redacted]	1.6	1-Nov-23	31-Oct-28
[redacted]	19.0	N/A	N/A
[redacted]	3.1	N/A	N/A
[redacted]	10.6	N/A	N/A
[redacted]	2.3	N/A	N/A
[redacted]	2.1	N/A	N/A
[redacted]	2.8	N/A	N/A
[redacted]	0.8	N/A	N/A
[redacted]	2.8	N/A	N/A
[redacted]	2.8	N/A	N/A
[redacted]	11.3	N/A	N/A
[redacted]	1.2	N/A	N/A
[redacted]	6.8	N/A	N/A
[redacted]	0.8	N/A	N/A
[redacted]	1.4	N/A	N/A
[redacted]	1.7	N/A	N/A
[redacted]	1.0	N/A	N/A
[redacted]	0.1	N/A	N/A
[redacted]	0.4	N/A	N/A
[redacted]	1.1	N/A	N/A
[redacted]	1.7	N/A	N/A
[redacted]	5.7	N/A	N/A
[redacted]	1.0	N/A	N/A
[redacted]	2.4	N/A	N/A
[redacted]	0.9	N/A	N/A
[redacted]	3.5	N/A	N/A
[redacted]	3.5	N/A	N/A
[redacted]	1.4	N/A	N/A
[redacted]	3.3	N/A	N/A
[redacted]	3.2	N/A	N/A
[redacted]	1.8	N/A	N/A
[redacted]	1.8	N/A	N/A
[redacted]	1.8	N/A	N/A

Distribution Contract Total	63.1
Letters of Indemnity / Commitment Letters	104.2
Total Commitments (TJ/d)	**167.3**

1 Start dates not applicable to a Letter of Indemnity or a Commitment Letter.
2 End dates not applicable to a Letter of Indemnity or a Commitment Letter.
3 Distribution Contracts continue on a year to year basis after the Initial Term of a Distribution Contract.

d) The capacity of the proposed Project is 203 TJ/day. The amount currently under binding commitment is 167 TJ/day, however the remaining 36 TJ/day of capacity is forecasted to be fully subscribed by Winter 2028/2029.

e) Confirmed.

Enbridge Gas's Panhandle System connects with the Panhandle Eastern Pipeline Company ("PEPL") system at Ojibway. The capacity for ex-franchise delivery is limited by the ability for PEPL system capacity to accept gas, which isn't known by Enbridge Gas at this time. There are currently no customers of Enbridge Gas with C1 service from Dawn to Ojibway and no requests have been received for this service by Enbridge Gas.

<Letter Date>

<Customers Legal Name>
<Property Address>
<City>, Ontario
<Postal Code>

Re: Commitment Letter ("CL") for the Panhandle Regional Expansion Project (the "Project")

Enbridge Gas Inc. ("**Enbridge Gas**") continues to experience strong growth in demand for natural gas service by new and existing customers in the municipalities of Chatham-Kent, Windsor, Lakeshore, Leamington, Kingsville, Essex, Amherstburg, LaSalle, and Tecumseh.

In order to meet this growing demand from our in-franchise customer markets (which include the residential, commercial, industrial and greenhouse sectors), Enbridge Gas is proposing to expand its Panhandle Transmission System and associated gas distribution facilities in the area. The proposed Project will help unlock access to abundant, affordable and clean natural gas supply.

Enbridge Gas is requesting that customers who are interested in securing natural gas service from the proposed Project demonstrate their commitment to it by executing this CL, confirming their intentions to proceed with a new or amended distribution contract.

1. <Customers Legal Name> and Enbridge Gas intend to formalize a contract for natural gas service (the "**Distribution Contract**"), which will be conditional upon, amongst other things, Enbridge Gas receiving all required internal approvals to proceed with the Project, and Enbridge Gas receiving Ontario Energy Board approval for the Project.

2. The Distribution Contract will be based on the following estimated contract parameters, conditions and understanding:

    a. <Customers Legal Name> agrees to a minimum 5-year (maximum 20-year) distribution contract for natural gas service based on the conditions outlined in the applicable Enbridge Gas distribution contract and an in service date of the later of <Effective Date>, or the in-service date of the Project.

    b. Natural gas service will be provided by Enbridge Gas to <Customers Legal Name> under the terms and conditions of the appropriate rate schedule(s), which are available here: https://www.enbridgegas.com/business-industrial/commercial-industrial/large-volume-services-rates/union-south (not including natural gas commodity related costs).

c. Incremental firm hourly quantity of <Incremental FHQ> m^3/hour, total firm hourly quantity of <Total FHQ> m^3/hour, firm daily contract demand of <Firm CD> m^3/day, and minimum annual volume of <Total MAV> m^3.

d. Customer is expected to execute a new or amended distribution contract no later than <1 year prior to requested in-service date>.

e. If a new or amended distribution contract is not executed by <1 year prior to requested in-service date>, Customer will be required to execute a Letter of Indemnification until a new or amended distribution contract is executed.

f. Customer shall have received all required financing as well as any Municipal, Provincial or Federal permits necessary, on or before <Specify Date>, to ensure the Customer's ability to construct its expansion facilities at <Customer Expansion Facilities Address> and honour the provisions of this CL.

g. Enbridge Gas shall have received all required internal approvals.

h. Enbridge Gas shall have received all required regulatory approvals.

3. <Customers Legal Name> has reviewed, and accepts the terms and conditions of the Distribution Contract.

4. Any additional financial contributions required from <Customers Legal Name> to provide natural gas service will be calculated and included in the new or amended distribution contract in the form of a contribution in aid of construction.

5. This CL shall expire at the earlier of a) <Expiry Date> or b) when the CL is replaced with a signed Distribution Contact or indemnification agreement.

6. <Customers Legal Name> hereby warrants that it has taken all appropriate and necessary corporate action to authorise the execution of this CL and the performance of the terms hereof represents a legally binding obligation on <Customers Legal Name> with the exception of paragraph 1 of this CL, which indicates the Parties' intentions.

7. Enbridge Gas hereby warrants that it has taken all appropriate and necessary corporate action to authorise the execution of this CL and the performance of the terms hereof represents a legally binding obligation on Enbridge Gas, with the exception of paragraph 1 of this CL, which indicates the Parties' intentions.
If you have any questions, please contact your account manager:

<Account Manager>
<Phone>
<Email>

If <Customers Legal Name> acknowledges and agrees with the foregoing, please execute below and return a copy to my attention by <Date>.

Yours truly,

____

<Enbridge Gas Authorized Person>
<Title>
Enbridge Gas Inc.

Acknowledged and accepted on behalf of <Customers Legal Name>

By: _________________________________

Name: ______________________________

Title: ________________________________

Date: _____________________

[Date]
[Name of Customer]
[Address]

Attention: []

Dear []

Re: Indemnity Letter for Enbridge Gas Inc. facilities at the [Location]

Enbridge Gas Inc. ("**the Company**") and [Name of Customer] ("**Customer**") have held discussions related to the provision of natural gas distribution and storage services (the "**Services**") [*NTD: text to describe the driver: for new facilities to be built by Customer / increased demand by the customer at the [Location] as of [date*]. Until a definitive natural gas distribution services agreement ("**Contract**") is executed by the parties hereto, the Company requires a written covenant from Customer to indemnify and save harmless the Company for all of the Project Costs related to the development and construction of any new Enbridge Gas Inc. facilities ("**Expansion Facilities**") needed to serve the new facilities.

In consideration of the Company undertaking certain development and construction activities related to the Expansion Facilities [*NTD: optional clause for times when further details are needed: as further described in Appendix []*]**,** and other good and valuable consideration the receipt and sufficiency of which is hereby acknowledged, Customer hereby irrevocably and unconditionally indemnifies and holds harmless the Company, and all of the Company's affiliates, employees, officers, and directors (collectively , the "**Indemnitees**") from all Project Costs which the Indemnitees or any of them may incur or suffer in respect of, or in connection with, or in any manner arising out of the development and construction of the Expansion Facilities. "**Project Costs**" means any and all costs, (including litigation costs, cancellation costs, carrying costs, and third party claims) expenses, losses, demands, damages, obligations, or other liabilities (whether of a capital or operating nature, and whether incurred or suffered before or after the date of this Indemnity Letter) by any of the Indemnitees (including amounts paid to affiliates for services rendered in accordance with the Affiliate Relationships Code as established by the Ontario Energy Board), in connection with or in respect of development and construction of the Expansion Facilities (including without limitation the construction and placing into service of the Expansion Facilities, the obtaining of all governmental, regulatory and other third party approvals, and the obtaining of rights of way,) whether resulting from any of the Indemnitees' negligence or not, except for any costs that have arisen from the fraud or wilful misconduct of any of the Indemnitees.

Except to the extent of any Project Costs arising out of the Customer's breach of contract, negligence, fraud, or wilful misconduct, Customer's liability under this Indemnity Letter will not exceed $ [Amount] CAD [including/excluding] taxes.

This Indemnity Letter will terminate on the earlier of (a) the date that the Contract is executed, or (b) [Expiry Date] unless extended in writing by mutual consent, provided, however, that if the termination occurs pursuant to item (b) of this Indemnity Letter, Customer shall pay to the Company for all Project Costs as herein defined. Such payment shall be within 30 days of the Company submitting an invoice for Project Costs to Customer. Interest on any amounts due hereunder will accrue at an effective monthly interest rate of 1.5%, compounded monthly, for a nominal annual interest rate of 18%. In the event of termination under item (b), the Company may invoice Customer for Project Costs, from time to time and at any time within 12 months of such termination.

This Indemnity Letter supersedes any prior agreements, understandings, negotiations, or discussions whether oral or written, between the Parties with respect to the subject matter hereof.

If Customer agrees to be bound by the foregoing, please execute below and return a copy to my attention.

Yours very truly,
Enbridge Gas Inc.

____
Authorized Signatory

Customer agrees to be bound by the foregoing:
[Name of Customer]

____
Authorized Signatory

PROJECT COSTS AND ECONOMICS

1. The purpose of this Exhibit is to provide an overview of the costs of the Project and the economic analysis that was completed to demonstrate that the Project is economically feasible and in the public interest.

2. This Exhibit is organized as follows:
   A. Project Cost
   B. Project Economics
      i. Stage 1 – Project Specific Discounted Cash Flow Analysis
      ii. Stage 2 – Benefit/Cost Analysis
      iii. Stage 3 – Other Public Interest Considerations
      iv. Summary of Stages 1 to 3 Analyses

A. **Project Cost**

1. The total estimated cost of the Project is $358.0 million, as shown in Exhibit E, Tab 1, Schedule 2. This cost includes: (i) materials; (ii) labour; (iii) external permitting and land; (iv) outside services; (v) contingencies; (vi) interest during construction; and (vii) indirect overheads. Excluding indirect overheads, the total estimated cost of the Project is $289.2 million. /U

2. The costs are based upon a class 3 estimate prepared in Q1 2023, updated to reflect market conditions based on Q4 2022 contractor responses to RFP, as per American Association of Cost Engineers standards, and include a contingency of approximately 8% applied to all direct capital costs reflecting the detailed engineering design stage of the Project and materials received to date. This contingency amount has been calculated based on the risk profile of the Project and is consistent with contingency amounts calculated for projects in similar stages of design and complexity completed by Enbridge Gas. /U

3. Table 1 below provide a comparison of Project pipeline costs to other recent Enbridge Gas pipeline projects in close proximity to the Project area. Table 1 compares the estimated cost of the current Project (Panhandle Loop) to the latest estimated cost of the Dawn to Corunna Replacement Project (EB-2022-0086). A high-level explanation of significant variances is provided in the notes to the table. /U

Table 1: Project Cost Comparison – Pipeline Costs ($ Millions) /U

Item No.	**Description**	**(a)** **Proposed Project** Panhandle Loop (EB-2022-0157)	**(b)** **Current Forecast** Dawn to Corunna (EB-2022-0086)	**(c) = (a) - (b)** **Variance to Actual**
	Pipeline Diameter	***NPS 36***	***NPS 36***	
	Length	***19 km***	***20 km***	
	Pipeline Material	***Steel***	***Steel***	
1	Materials	28.3	26.1	2.2
2	Labour	150.8	123.1	27.7
3	Contingency	13.9	2.6	11.3
4	Interest During	6.4	3.7	2.7
5	**Total Direct Capital Cost**	**199.5**	**155.5**	**44.0**
6	Indirect Overheads	48.0	33.4	14.6
7	**Total Project Cost**	**247.5**	**188.9**	**58.6**
8	Total Cost per km	13.0	9.4	3.6
9	Material Cost per km	1.5	1.3	0.2
10	Labour, External permitting and land, and Outside Services per km	7.9	6.2	1.7
11	**Total Ancillary Facilities Direct Capital Cost**	**89.7**	**127.1**	**(37.4)**
12	Ancillary Facilities Indirect Overheads	20.8	23.3	(2.5)
13	**Total Ancillary Facilities Project Cost**	**110.5**	**150.4**	**(39.9)**
14	**Total Project Cost (Mainline and Ancillary Facilities) $ Millions**	**358.0**	**339.3**	**18.7**

NOTES:

- The proposed Project mainline estimate is inclusive of the Richardson Sideroad end point valve site.
- The proposed Project has a more complex mainline scope with eight (8) trenchless crossings compared to one (1) trenchless crossing for the Dawn to Corunna Replacement Project.
- Reduced contingency for the Dawn to Corunna Replacement Project due to its current stage of development/execution.

/U

B. <u>Project Economics</u>

4. The purpose of this section of evidence is to discuss the economic analysis of the Project, completed in accordance with the OEB's recommendations in E.B.O. 134 Report of the Board ("E.B.O. 134"). E.B.O. 134 is the appropriate economic test to apply to the Project, as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect. The use of E.B.O. 134 for the Project is also consistent with recent expansions to Enbridge Gas's Panhandle System approved by the OEB.[1]

5. To provide the OEB with supporting information, a Discounted Cash Flow ("DCF") analysis, consistent with E.B.O. 134, has been completed.

6. Stage 1 consists of a DCF analysis specific to Enbridge Gas. All incremental cash inflows and outflows resulting from the Project are identified. The NPV of the cash inflows is divided by the NPV of the cash outflows to arrive at a profitability index ("PI"). If the NPV of the cash inflows is equal to or greater than the NPV of the cash outflows, PI is equal to or greater than 1.0 and the Project is considered economic based on current approved rates. If the Project NPV is less than $0 or the PI is less than 1.0, Stage 2 and 3 benefit/cost analysis must be undertaken.

7. Stage 2 consists of discounting the quantified benefits to customers resulting from the Project at a social discount rate and the results are added to the Project NPV from Stage 1 to calculate the direct net benefit of the Project to Enbridge Gas customers.

   The Project is considered to be in the public interest if the net benefit is greater than $0.

---

[1] Union Gas Panhandle Reinforcement Project: EB-2016-0186, Union Gas Kingsville Transmission Reinforcement Project: EB-2018-0013.

8. Stage 3 analysis considers other quantifiable benefits and costs related to the construction of the Project, not included in the Stage 2 analysis, and other non-quantifiable public interest considerations.

i. Stage 1 – Project Specific Discounted Cash Flow Analysis /U

9. The Stage 1 DCF analysis for the Project can be found at Exhibit E, Tab 1, Schedule 5. This schedule indicates that the Project has a NPV of negative $150 million and a PI of 0.48.

10. A summary of the key input parameters, values and assumptions used in the Stage 1 DCF analysis can be found at Exhibit E, Tab 1, Schedule 3.

11. Incremental cash inflows are estimated based on the transmission portion ("transmission margin") of 2023 OEB-approved rates.[2] The revenue calculation for the transmission margin can be found at Exhibit E, Tab 1, Schedule 4. /U

12. Incremental cash outflows, in accordance with E.B.O. 134, include all estimated incremental Project costs. Indirect overhead is not included within cash outflows.

13. The total estimated incremental cost of $289.2 million can be found at Exhibit E,Tab 1, Schedule 2, Line 7.

ii. Stage 2 – Benefit/Cost Analysis

14. A Stage 2 analysis was undertaken as the Stage 1 NPV is less than zero (negative $150 million). The Stage 2 analysis considers the estimated energy cost savings that accrue directly to Enbridge Gas in-franchise customers as a result of using natural /U

[2] EB-2022-0133

gas instead of another fuel to meet their energy requirements. The difference in fuel cost is derived as:

[Weighted Average Alternative Fuel Cost - Cost of Natural Gas] × Energy Use

15. The Stage 2 NPV of energy cost savings are estimated to be in the range of approximately $226 million over a period of 20 years to $353 million over 40 years. A range is provided as the outcome can vary depending upon the assumptions for alternative fuel mix, energy use, fuel prices, and term. /U

16. The Stage 2 energy cost savings have only been calculated for the general service customer class. It is assumed that contract rate customers will not choose an alternative fuel if natural gas is not available to them. The non-availability of natural gas will cause contract rate customers to expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served. The resulting impacts to the Ontario economy are addressed in Stage 3.

17. The results and assumptions associated with this analysis can be found at Exhibit E, Tab 1, Schedule 6.

iii. Stage 3 – Other Public Interest Considerations

18. There are several other public interest factors for consideration as a result of the Project. Some are quantifiable and others are not readily quantifiable. Quantifiable factors include GDP, taxes, and employment impacts. Applicable other public interest factors are discussed below:

/U

<u>Economic Benefits for Ontario</u>

19. The construction of the Project will provide direct and indirect economic benefits to

Ontario estimated at approximately $257 million, as detailed at Exhibit E, Tab 1, Schedule 7. This figure is related only to the construction of the Project and does not include the similar direct and indirect economic benefits to Ontario when natural gas customers receiving this incremental supply invest and grow their operations. Customers who submitted EOI bids in 2021 were requested to provide economic development impacts related to their incremental natural gas needs. In the EOI bid responses, customers indicated that total direct capital investment into their business operations in Southern Ontario would exceed $6.37 billion. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in total direct capital investment in Southwestern Ontario exceeding $4.5 billion.[3]

<u>Employment</u>

20. The construction of this Project will result in additional direct and indirect employment. There will be additional employment of persons directly involved in the construction of the Project. In addition, there will be a trickledown effect on employment as the Project is estimated to create approximately 1,093 jobs as referenced at Exhibit E, Tab 1, Schedule 7. /U

21. Customers who submitted EOI bids in 2021 indicated that a total of 11,526 jobs could be created through the investment into their business operations enabled by the incremental capacity of the proposed Project. These figures were updated via the 2023 EOI bid forms. Although, the Company only received relevant feedback from 75% of customers who bid in 2023 (relative to 100% in 2021) the Project is still anticipated to result in the creation of 6,900 jobs.[4] /U

[3] Implying a comparable result to 2021, since $4.5 billion is 75% of $6 billion total potential.
[4] Implying a comparable result to 2021, since 6,900 jobs is 75% of 9,200 total potential.

Utility Taxes

22. A decision to proceed with this Project will result in Enbridge Gas paying taxes directly to various levels of government. These taxes include Ontario income taxes and municipal taxes paid by Enbridge Gas as a direct result of the Project and are included as costs in the Stage 1 DCF analysis. These taxes are not true economic costs of the Project since they represent transfer payments within the economy that are available for redistribution by federal, provincial, and municipal governments. The NPV of Ontario income taxes and municipal taxes payable by Enbridge Gas related to the Project over the Project life is approximately $45 million with a further $22 million paid to the federal government. These figures are further detailed at Exhibit E, Tab 1, Schedule 7.

Employer Health Taxes

23. The additional employment resulting from construction of the Project will generate additional employer health tax payments to aid in covering the cost of providing health services in Ontario.

iv. Summary of Stages 1 to 3 Analyses

24. Table 3 below shows the NPV calculated for the 3-Stage economic analysis completed for the Project.

Table 3: NPV Calculation /U

Stage	NPV ($millions)
1	($150)
2	$226 to $353
3	$257
Total	$333 to $460

25. As set out above, the Project is in the public interest and the tests set out in E.B.O. 134 are appropriate for the purposes of evaluating the Project. Based on these tests, /U

the Project has a net present value of $333 million to $460 million and is economically feasible.

26. On Februry 21, 2013, the Board issued a new requirement to the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications with respect to E.B.O. 134 (EB-2012-0092):[5]

> Any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipeline(s) on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability and access to supplies.

27. These impacts have been addressed throughout this application and evidence. Table 4 below summarizes these impacts and provides references to additional detail.

Table 4: Project Impact to Customers

Entity Impacted		**Summary of Impact**	**Reference**
Existing Infrastructure	Enbridge Gas	Enbridge Gas is proposing to construct: i) 19 km of NPS 36 pipeline that will parallel the existing NPS 20 pipeline from the Dover Transmission Station to a new valve site at Richardson Sideroad	Exhibit D, Tab 1, Schedule 1
Impacts to Ontario consumers	Costs and Rates	Enbridge Gas is not seeking cost recovery of the Project as part of this application. Enbridge Gas expects that, upon rebasing, the capital costs associated with the Project will be included within rate base. Enbridge Gas will allocate Project costs to rate classes according to the applicable OEB-approved cost allocation methodology in place at the time the Company applies for such rate recovery.	N/A
	Reliability and Access to Supplies	In response to increased forecast of demand growth, the Project will create incremental reliable firm transportation assets on the Panhandle System. Project also supports increased access to the Dawn Hub for the Panhandle Market, providing lower cost and greater reliability.	Exhibit B, Tab 3, Schedule 1 Exhibit C, Tab 1, Schedule 1

/U

[5] EB-2012-0092, Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, February 21, 2013, P. 3.

PREP - Panhandle Regional Expansion Project
InService Date: Nov-01-2024
(Project Specific DCF Analysis)

Stage 1 DCF - Listing of Key Input Parameters, Values and Assumptions
($000'S)

Discounting Assumptions	
Project Time Horizon	40 years commencing at facilites in-service date of 01 Nov 24
Discount Rate	Incremental after-tax weighted average After Tax Cost of Capital of 5.85%
Key DCF Input Parameters, Values and Assumptions	
Net Cash Inflow:	
Incremental Revenue:	
Transmission portion of customer rates	0.180895 $/ M3 / month applied to Contract Demand 0.022334 $ / M3 applied to general service volume
Operating and Maintenance Expense	Estimated incremental cost
Incremental Tax Expenses:	
Municipal Tax	Estimated incremental cost
Income Tax Rate	26.50%
CCA Rates:	
CCA Classes:	Declining balance rates by CCA class:

CCA Classes:	CCA Class	CCA Rate
Land	-	-
Land Rights	14.1	5%
Transmission Mains - Metallic	49	8%
Measurement & Regulating Equipment	8	20%

Cash Outflow:	
Incremental Capital Costs Attributed	Refer to Exhibit E, Tab 1, Schedule 2, Line 7
Change in Working Capital	5.051% applied to O&M

Panhandle Regional Expansion Project
Economic Benefits from Infrastructure Spending
Figures in $ Millions

Line No	Description	Capex Spend Out of Country (a)	Capex Spend within Ontario (b)		Capex Spend within Canada Excluding Ontario (c)	Capex Total (d)= sum (a-c)	
1	Proposed Facilities	$ 47	$ 232		$ 10	$ 289	
2							
3	% of Total Spend	16%	80%		4%	100%	Line 1 /Total Line 1 Col (d)
4							
5	GDP						
6	GDP Factor		0.91	*			
7	GDP Impact $ Millions		$ 212				Line 1 * Line 6
8							
9	Employment (Jobs)						
10	Jobs Factor		4.7	*			
11	Jobs Created		1,093				Line 1 * Line 10
12							
13	Taxes Paid by Union Gas						
14	Property Tax		$ 17				Source: NPV DCF
15	Provincial Income Tax		$ 28				Source: NPV DCF
16	Total Provincial Taxes		$ 45				
17	Federal Income Tax		$ 22				Source: NPV DCF
18	Total Taxes Paid		$ 67				
19							
20	Total Value to Ontario						
21	GDP Impact $ Millions		$ 212				Line 7
22	Total Provincial Taxes		$ 45				Line 16
23	NPV Total Value to Ontario		$ 257				

Notes:
* The Economic Benefits of Public Infrastructure Spending in Ontario, Prepared for Ministry of Economic Development and Growth, Ministry of Finance, Ministry of Infrastructure. Prepared by The Centre For Spatial Economics, March 2017.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Ex. B, Tab 1, Schedule 1.

Question:

(a) Please provide a copy of table 1 on page 11 with the figures converted to m3/d.
(b) Please provide conversation factors for TJ to m3.
(c) On page 14, Enbridge states: "The greenhouse sector does not currently have a viable economic alternative to replace natural gas for heat and CO2 production." Please provide an analysis comparing the cost of heating a greenhouse with gas versus a high-efficiency heat pump. Please provide this analysis over a 15 year time horizon, including the federal government's planned increases to the carbon price.

Response

a) Please see Table 1.

Table 1

/U

	Historical Actuals (m3/d)			FORECAST (m3/d)								
	Winter 19/20	**Winter 20/21**	**Winter 21/22**	**Winter 22/23**	**Winter 23/24**	**Winter 24/25**	**Winter 25/26**	**Winter 26/27**	**Winter 27/28**	**Winter 28/29**	**Winter 29/30**	**Winter 30/31**
General Service Firm (Total)	8,137,763	7,853,310	7,884,028	7,832,260	7,880,854	7,928,707	7,974,872	8,019,785	8,062,781	8,104,141	8,143,482	8,180,905
Contract Firm (Total excluding Power Generators)	5,591,970	6,144,934	6,500,153	7,309,867	8,082,515	8,408,921	8,735,302	9,061,708	9,388,113	9,714,519	10,040,900	10,367,306
Power Generators - Firm Contract only	2,697,871	2,706,441	2,700,102	2,701,022	2,701,022	4,168,021	4,987,398	4,987,398	4,987,398	4,987,398	4,987,398	4,987,398
Total System Demand Forecast	16,427,604	16,704,684	17,084,283	17,843,149	18,664,392	20,505,649	21,697,572	22,068,891	22,438,292	22,806,058	23,171,779	23,535,608
General Service Firm (Total Incremental Demand)	486,326	(222,301)	38,708	(92,076)	48,594	47,853	46,166	44,913	42,996	41,360	39,340	37,423
Contract Firm (Incremental excluding Power Generators)	627,860	595,672	361,470	776,483	772,648	326,406	326,380	326,406	326,406	326,406	326,380	326,406
Power Generators - Firm Contract only (incremental)	(565,777)	29,175	(3,586)	(12,883)	-	1,466,999	819,376	-	-	-	-	-
Total Incremental Demand Forecast	548,409	402,546	396,592	671,524	821,242	1,841,258	1,191,922	371,319	369,402	367,766	365,721	363,829
Total Incremental Demand Forecast (Cumulative)	-			671,524	1,492,766	3,334,024	4,525,946	4,897,265	5,266,667	5,634,433	6,000,153	6,363,983

b) The conversion factor from TJ per day to m^3 per day is based on the System Wide Average Heating Value ("SWAHV") which is updated annually. The conversions are as follows: /U

- For Winter 2019/2020: 0.00003898 TJ/m^3
- For Winter 2020/2021: 0.00003928 TJ/m^3
- For Winter 2021/2022: 0.00003932 TJ/m^3
- For Winter 2022/2023 to W2030/2031: 0.00003912 TJ/m^3

c) Enbridge Gas has not developed an analysis comparing the cost of heating a greenhouse with natural gas versus an electric heat pump. The reference to the viability of alternative solutions for heating and CO_2 production for greenhouses is based on the utility's understanding of greenhouse operations, as well as greenhouse customer requirements for natural gas via the EOI process. Enbridge Gas is not aware of any large greenhouse customers that use electric heat pumps for heating and CO_2 production.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1

Question:

(a) What is the expected lifetime of the proposed pipeline?
(b) When would the proposed pipeline be fully depreciated?
(c) What will the undepreciated balance of the proposed pipeline costs be in (i) 2035, (ii) 2040, and (iii) 2050?
(d) Has Enbridge conducted an analysis to assess the likelihood, if any, that the proposed pipeline will be stranded or underutilized before the end of its lifetime? If yes, please file said analysis.
(e) Please estimate the probability (if any) that the proposed pipeline will be stranded or underutilized before the end of its lifetime. Please provide the response as a probability (%) or a range of probabilities. For instance, if there is no chance, please indicate the probability as 0%.

Response

a) The current OEB-approved depreciation rate for transmission pipelines in the Union Rate Zone assumes an economic life of 55 years.

b) Assuming current OEB-approved depreciation rates, the proposed pipeline will be fully depreciated in 2075. /U

c) The undepreciated balance of the proposed pipeline(s) is: /U
   i. in 2035 = $146 million
   ii. in 2040 = $128 million
   iii. in 2050 = $91 million

d) and e)

No, the proposed Project is based on best available demand forecasts, customer commitments, and is designed to reliably serve known increased demands for firm service in the Panhandle Market, including, in particular, incremental demands from the greenhouse, automotive, and power generation sectors. The Company has no basis to believe the proposed pipeline will be undersubscribed or stranded.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

- Exhibit C, Tab 1, Schedule 1, p. 5
- Exhibit F, Tab 1, Schedule 1, Attachment 1, "Environmental Report, Panhandle Regional Expansion Project" (the "Environmental Report")

Preamble:

EGI has assessed the following facility alternatives:
(i) Upsizing of the existing NPS 16 Panhandle Line or NPS 20 Panhandle Line west of Dover Transmission;
(ii) Looping the existing NPS 20 Panhandle Line West of Dover Transmission and installing a Leamington lateral interconnect (ie. the Project); and
(iii) A new liquified natural gas (LNG) Plant.

EGI identified and assessed the following Integrated Resource Planning Alternatives ("IRPA"):

(i) Firm exchange between Dawn and Gateway;
(ii) Firm exchange between Dawn and Ojibway, in combination with looping the NPS 20 Panhandle line west of Dover Transmission and installing a Leamington lateral interconnect;
(iii) Trucked CNG deliveries to the Panhandle system; and
(iv) Enhanced Targeted Energy Efficiency (ETEE).

Question:

a) Please explain why only two facility alternatives, an upsize of existing pipelines and the construction of a new LNG plant, were considered and assessed, as opposed to other non-natural gas-based options?
b) Please indicate whether EGI has considered hybrid solutions for the Project and the expansion of the Panhandle System. If yes, please provide details and indicate why these solutions were considered with respect to financial impacts on ratepayers, and why/how they were ruled out of inclusion for further consideration. If not, please explain.

c) Has Enbridge sought any opportunities to work with IESO or any other electricity distributors to facilitate electricity-based energy solutions as part of the IRPA for the benefit of both electricity and gas ratepayers, and if not, why was this not done?
d) Has Enbridge assessed the need for the project in relation to any rapid expansion of electricity infrastructure in the region, and overall impacts on both electricity and gas ratepayers?
e) Would Enbridge expect any rapid expansion of electricity infrastructure in the region to impact the need for the proposed project?
f) How does Enbridge determine whether the alternatives it has chosen to assess represent a complete picture of the viable alternatives to the Project? What criteria are used by EGI when selecting and assessing potential project alternatives and IRP's?
g) Please explain how Enbridge assessed alternatives to the project with respect to short-term and generational financial impacts on ratepayers
h) Please explain how Enbridge assessed alternatives to the project, specifically as they relate to impacts on each of the Three Fires First Nations.
i) Please explain what project alternatives, including financial impacts on ratepayers, including First Nation ratepayers, were presented to each of the Three Fires First Nations.

Response

a) Through Enbridge Gas's assessment of facility alternatives, no additional alternatives were identified to meet customer demand. Please see Exhibit C, Tab 1, Schedule 1 for Enbridge Gas's assessment of project alternatives. Please also see the response to Exhibit I.STAFF.7 for more information on all alternatives assessed, including various facility alternatives. /U

Enhanced Targeted Energy Efficiency were also assessed under IRPAs (see Exhibit C, Tab 1, Schedule 1, Pages 10-21) and deemed not to be viable (please also see the response to Exhibit I.STAFF.7 Attachment 2).

b) Yes, hybrid alternatives were considered, including the IRPA described at Exhibit C, Tab 1, Schedule 1, Pages 16-19. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7. /U

c) No, Enbridge Gas did not identify viable electricity-based alternatives for the Project. However, Enbridge Gas did assess Enhanced Targeted Energy Efficiency ("ETEE") programming, but this alternative was deemed to be non-viable. For more information on the assessment of alternatives, please see the response at Exhibit I.STAFF.7.

The need for the proposed Project is underpinned by customer demands for natural gas specifically (as per the EOI process), which is used by natural gas-powered electricity generators as a supply input, to power their facilities, and by agricultural customers for heating and carbon dioxide (to feed plants). Electricity is typically used by agricultural customers for lighting and ventilation only.

d) No.

Customers in the Panhandle Area of Benefit were invited to share their new/incremental gas needs through the EOI process. They were also invited to share any plans to turnback or reduce current contract demands. The EOI was used to generate an informed forecast for net new expected demands in the Panhandle Market.

e) No.

As per the IESO reports (2021 APO & 2022 AAR), the rapid expansion of electricity infrastructure in the region is in response to growing demands and does not make reference to existing customers in the region converting their existing energy needs currently met by natural gas to electricity.

f) Enbridge Gas conducts an assessment to identify potential alternatives, including facility and non-facility alternatives, to provide a complete picture of options to meet customer demand. For the criteria used to assess alternatives, please refer to Exhibit C, Tab 1, Schedule 1, Pages 3-4.

g) Enbridge Gas assessed alternatives for economic feasibility (Exhibit C, Tab 1, Schedule 1, Page 3). This included an assessment of Net Present Value and cost per unit of capacity created, to assess long-term impacts. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7. /U

h) Enbridge Gas assessed alternatives for environmental and socio-economic impact (Exhibit C, Tab 1, Schedule 1, Page 4), recognizing that the chosen alternative should minimize impacts to Indigenous peoples, municipalities, landowners, and the environment relative to other viable alternatives. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7.

i) Please see the response to Exhibit I.TFG.1 part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

Environmental Report, Integrated Resource Planning (IRP), PDF p. 310

Preamble:

IRP is a framework through which Enbridge Gas reviews alternative approaches to meeting energy needs, before building new infrastructure such as:
(i) Delivering more energy without adding new pipelines using liquefied or compressed natural gas;
(ii) Lowering energy use through effective energy efficiency programs; and
(iii) Displacing conventional natural gas with carbon-neutral renewable natural gas and hydrogen.

Question:

a) Has EGI considered whether the existing system could deliver more energy without adding new pipelines? If so, please explain and include reasons for why this alternative is not feasible.
b) Has EGI considered whether energy efficiency programs could meet regional energy needs and possibly provide better financial cases for ratepayers? Please explain.
c) Will alternative fuels like renewable natural gas and hydrogen blends be transported in the existing loop and new pipeline? If so, how has EGI considered the impacts on ratepayers for those alternative fuels?
d) If alternative fuels will be transported, please comment on the measures taken to ensure pipeline integrity, and related integrity management costs to ratepayers. Please include short- and long-term measures.

Response

a) Yes, alternatives that deliver more energy without incremental pipeline facilities were considered. The alternative assessment evaluation included Liquefied Natural Gas, Compressed Natural Gas and incremental third-party supplies. These alternatives were determined to be non-viable mitigation for the forecast Panhandle System capacity shortfall (please see the response to Exhibit I.STAFF.7 Attachment 2).

b) Yes, as noted at Exhibit C, Tab 1, Schedule 1, Pages 20-21, Enbridge Gas assessed whether energy efficiency programs could meet the regional energy needs compared to the capacity created by the proposed Project. The assessment found that the Enhanced Targeted Energy Efficiency ("ETEE") alternative is not technically or economically feasible to meet forecasted demands. /U

c) and d)
Enbridge Gas believes that the natural gas system could be leveraged to reduce GHG emissions in Ontario by transitioning the system over time to deliver renewable natural gas ("RNG") and hydrogen. Contract customers who are direct purchase may purchase RNG as part of their supply. As proposed in Phase 2 of Enbridge Gas's Rebasing Application (EB-2022-0200) at Exhibit 4, Tab 2, Schedule 7, the Company has proposed a new Low Carbon Voluntary Program to enable system supplied customers the ability to voluntarily elect that a portion of their supply be RNG, pending OEB approval, beginning in 2025. However, Enbridge Gas has no immediate plans to blend RNG or hydrogen into the Panhandle System. /U

RNG is composed of mostly methane, as is natural gas, and is currently injected by various producers into some of Enbridge Gas's systems. This RNG is blended within the natural gas stream. RNG is a one for one replacement of natural gas by volume and therefore would not have an impact on the proposed Project. Pipeline integrity measures for RNG are similar to those for traditional natural gas.

Enbridge Gas intends to evaluate the compatibility of its pipeline facilities with hydrogen gas in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

INTERROGATORY

Question(s):

Has Enbridge conducted a risk assessment on the probability that the proposed Project will become a stranded asset before being fully depreciated? If yes, please provide a copy of the assessment and all related materials. If no, what evidence exists to support that the pipeline will remain used and useful for the full amortization period.

Response:

Enbridge Gas has no reasonable basis to believe that the proposed facilities will become stranded assets and thus has had no reason to complete the assessment in question.

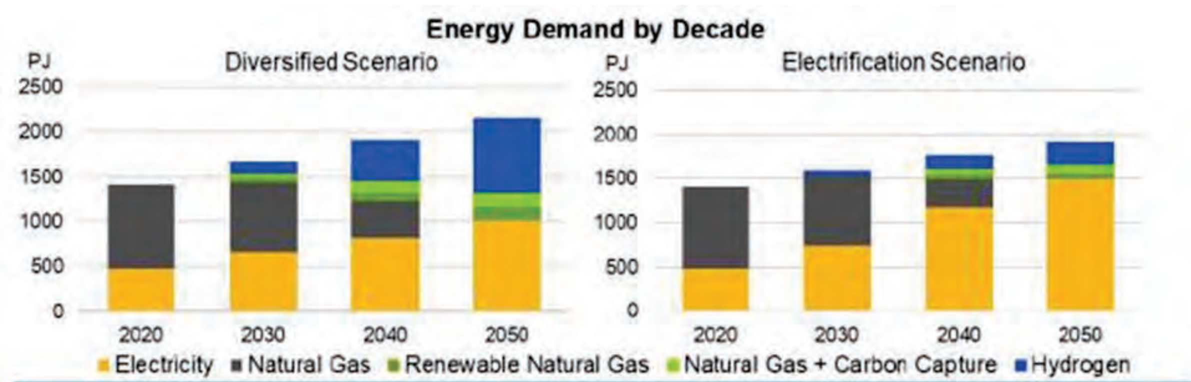
ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

INTERROGATORY

Reference:

Pathways to Net Zero Emissions for Ontario 1.



Question(s):

Enbridge indicates that for both the (Enbridge-preferred) Diversified Scenario and the Electrification Scenario that by 2050 natural gas will no longer be used in Ontario with the potential exception of select large volume industrial customers that have economic access to carbon capture and geological sequestration.

a) Please explain why an amortization period past 2050 (i.e. greater than 25 years) is appropriate if natural gas will no longer be available to these customers prior to 2050.

b) Please confirm that Enbridge has not received approval (from the OEB, TSSA or other relevant regulator) for use of 100% hydrogen for the Project assets proposed. If approval has been received for 100% hydrogen, please provide a copy of such approval.

c) If Enbridge intends to use hydrogen to serve Panhandle customers once natural gas is no longer available, please provide details on the source, transmission and lifecycle carbon emissions of the proposed hydrogen.

Response:

a) PP's interrogatory is premised on an inaccurate characterization of the Pathways to Net Zero Emissions for Ontario Study ("P2NZ"). The objective of the P2NZ study was not to forecast, predict or define an "Enbridge-preferred" future Ontario scenario, rather, the analysis was meant to consider different scenarios, each with a set of established assumptions, for how Ontario's energy system might support the achievement of net zero emissions by 2050 in the province. There are many different permutations that a diversified scenario could take.

   Enbridge Gas submits that the P2NZ's net-zero emissions by 2050 provincial-level scenario analyses does not represent a forecast or prediction of what is expected to occur in the Panhandle project's areas of impact. Enbridge Gas's natural gas demand forecast for the Project relies on the energy interests expressed by actual customers within the Project area. Based on the current demand forecast, Enbridge Gas does not have any indication that the pipe would not be utilized in or post 2050 and, therefore, at this point in time does not believe that an amortization of 25 years would be appropriate. If Enbridge Gas becomes aware of customers leaving the system or decreased utilization in the future, it will revise depreciation studies to accelerate recovery to reduce risk of stranded costs.

b) Confirmed.

c) Enbridge Gas has proposed a Hydrogen Blending Grid Study (EB-2022-200, Exhibit 4, Tab 2, Schedule 6, pages 16 to 18) to help identify and prioritize the sections of the gas grid most suitable for hydrogen blending and to identify associated costs and benefits. Until the completion of this study, it is not yet known how hydrogen may be able to serve the Project area.

EGI Asset Management Plan Addendum – 2024

October 31, 2023

Company: Enbridge Gas Inc.

Owned by: Asset Management Department

Controlled Location: Asset Management TeamSite

- 43 investments under the Asset Class of Growth are in the queue to have their technical evaluations completed by the end 2023.
- 5 investments under the Asset Class of Transmission Pipe & Underground Storage will have the options assessed prior to the Leave to Construct (LTC) application.
- 197 investments under the Asset Class of Distribution Pipe have an IRP evaluation status of "On Hold"[10]. These investments will be re-evaluated annually for project scope and timing updates to allow for appropriate resource allocation for the IRP evaluation process.
- 9 investments in the EDIMP have a technical evaluation status of "In Progress" and are awaiting further integrity assessment to confirm project scope and timing. Preliminary technical evaluations have been conducted based on the current scope of the investments in 2023 – 2032 AMP. Technical evaluations will be updated to include the scope impacts of the Asset Management portfolio from the EDIMP integrity assessment.

- Investments that have passed the technical evaluation will proceed to the economic evaluation stage. No economic evaluations have been completed at the time of filing this addendum.

The following list highlights the IRP evaluation progress of the 1194 new investments to Appendix B:

- 140 (11.7%) were deemed not subject to any IRP process because they related to non-gas-carrying investments.
- 904 (75.7%) were screened out using binary screening.
- 66 (5.5%), at the time of filing this addendum, had undergone a completed technical evaluation, and none had passed the evaluation.
- 84 (7.0%) remain to undergo technical evaluation or are being technically evaluated as of the time of filing this addendum.
  - 24 investments under the Asset Class of Growth are in the queue to have their technical evaluations completed by the end of 2023.
  - 60 investments under the Asset Class of Distribution Pipe and Distribution Station have an IRP evaluation status of "On Hold". These investments will be re-evaluated annually for project scope and timing updates to allow for appropriate resource allocation for the IRP evaluation process.

5.2 Energy Transition

EGI has incorporated Energy Transition[11] impacts to the Customer Connections forecast and ensured appropriate adjustments have been reflected in the Growth and Utilization asset classes, including Customer Connections portfolios under Growth, in the updated 2024 Budget under **Table 6.0-1**. These impacts are in alignment with undertaking response *EB-2022-0200, Exhibit J14.2*, and lower Gas Infrastructure - Growth & Customer Connections investment by $2.0M in 2024 due to the reduction in customer attachments by 322[12] after Energy Transition assumptions are incorporated. Note that Energy Transition assumptions had previously been incorporated into the Distribution System Reinforcement forecast under Growth in the 2023 – 2032 AMP and in the Capital Update[13] filed in Phase 1 of the rebasing application.

EGI has committed to evolving its Energy Transition plan, including conducting a regional Energy Transition analysis with stakeholder engagement, which the Company proposes to file with the next rebasing application.[14] In the interim, EGI will continue to evolve its demand forecasting process, including to review and, where required, update the Energy Transition assumptions used in the forecasts of customer additions, design hour, and design day. EGI intends that future IRP

[10] On hold due to project timing/scoping to be confirmed.
[11] EB-2022-0200, Exhibit 1, Tab 10, Schedule 4
[12] EB-2022-0200, Exhibit I.2.6-ED-94, Table 2
[13] EB-2022-0200, Exhibit 2, Tab 5, Schedule 4
[14] EB-2022-0200, Reply Argument, paragraph 78, filed October 11, 2023

assessments included with a LTC, or IRP plan filed with the OEB will incorporate the assessment of demand forecast sensitivities to consider Energy Transition related uncertainties.[15] In its Reply Argument in EB-2022-0200, EGI has proposed updated customer attachment policies to be in effect as of January 1, 2025. The implications of these changes will be reflected in the 2025 – 2034 AMP.

5.3 Integrity Management Program Enhancements

EGI continues to evolve its Integrity Management Program based on industry best practices and incident learnings. EGI has developed a quantitative risk model to assess the risk for pipeline assets within the distribution system that identifies and prioritizes assets approaching the end of life that need replacing. Ninety-nine percent of the transmission pipeline assets are already assessed using the quantitative risk model with the balance to be incorporated by the end of 2023. Improvements have been made to the transmission risk model to include additional hazards, consequences, and the application of Safety Targets, to align with EGI's risk evaluation criteria.

In addition, EGI recently introduced an EDIMP which is a targeted program to manage the Integrity threats of higher-priority distribution pipelines, by improving the understanding of the condition, fitness for service, and risks associated with the operation of those assets.

5.4 Growth Strategy Developments

5.4.1 Panhandle Regional Expansion Project

The Panhandle Regional Expansion Project (PREP)[16] is required to provide a reliable, secure, economical natural gas supply to meet the growing design day demand of the EGI Panhandle Transmission System which serves in-franchise markets (including residential, commercial, and industrial customers). The project need was originally determined based on nonbinding Expression of Interest (EOI) conducted in February 2021 followed by a binding Reverse Open Season (ROS) in October 2021.

On June 10, 2022, EGI applied to the OEB under docket *EB-2022-0157* for LTC the following facilities, which were also reflected in EGI's 2023 – 2032 AMP and Capital Forecast filed in *EB-2022-0200 Exhibit 2, Tab 6, Schedule 2*:

- Approximately 19 km of Nominal Pipe Size (NPS) 36 natural gas pipeline with a Maximum Operating Pressure (MOP) of 6,040 kPag from the existing Enbridge Gas Dover Transmission Station in the Municipality of Chatham-Kent to a new valve site in the Municipality of Lakeshore (Panhandle Loop); and,
- Approximately 12 km of NPS 16 natural gas pipeline with a MOP of 6,040 kPag in the Municipality of Lakeshore, the Town of Kingsville, and the Municipality of Leamington (Leamington Interconnect).

On February 1, 2023, EGI filed a letter stating that, following the receipt of new cost information, the Company also reassessed the capacity position of the Panhandle System based on actual 2022 attachments and their system locations, as well as updated 2023 customer demand. As a result, the Company anticipated that incremental demand for Winter 2023/2024 could be accommodated and that the project's in-service date could be deferred one year from November 1, 2023, to November 1, 2024. Based on this, EGI asked the OEB to continue holding the application in abeyance until no later than August 2023. On February 23, 2023, EGI launched a second nonbinding EOI and concurrent binding ROS for the Panhandle Market. As a result of the EOI and ROS, the original project in-service date was deferred one year, from November 1, 2023, to November 1, 2024. In addition, EGI also adjusted the project's proposed scope by removing the Leamington Interconnect.

On June 16, 2023, EGI filed its amended LTC application for PREP based on the following scope of proposed facilities:

- No change in scope to the Panhandle Loop (i.e., 19 km of NPS 36 natural gas pipeline), with an updated estimated in-service date of November 1, 2024 (previously November 1, 2023). The Leamington Interconnect has been removed from the application.

[15] EB-2022-0200, Reply Argument, paragraph 128, filed October 11, 2023
[16] EB-2022-0157

ONTARIO ENERGY BOARD

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

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

REPLY ARGUMENT OF ENBRIDGE GAS INC.

Aird & Berlis LLP
Barristers and Solicitors
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, Ontario
M5J 2T9

David Stevens
Email: dstevens@airdberlis.com

Dennis O'Leary
Email: doleary@airdberlis.com

Tel: 416-863-1500
Fax: 416-863-1515

Counsel to Enbridge Gas

Ontario do not have a large amount of spare capacity on each of their feeder circuits, then transition from gas to electricity cannot take place until the electricity distributors build additional capacity, which may take years, cost a lot of money, and increase rates."[86]

Enbridge Gas Future Steps on Energy Transition

78. It is important to emphasize that Enbridge Gas always intended to evolve its ETP and to include more stakeholder collaboration and involvement.[87] Upon review of Dr. Hopkins' recommendations, Enbridge Gas agrees that a regional level analysis is an important addition to Enbridge Gas's next ETP. Enbridge Gas believes that this work would be most valuable to initiate, scope and conduct once government policy is clarified; however, it may be necessary to start the work sooner to meet expected OEB filing timelines. Understanding that the EETP's recommendations are not expected until the end of 2023 at the earliest, associated government policies will be issued sometime following these recommendations, likely after a consultation period, and that Enbridge Gas will require time to complete regional analysis, develop associated plans and proposals and engage stakeholders, Enbridge Gas submits that the appropriate time to file its evolved ETP is with its next rebasing application.

79. Assuming that the next rebasing filing would be for 2029 rates, Enbridge Gas would need to file its evidence by Fall 2027. The business planning processes required for Enbridge Gas to develop the next iteration of its ETP involves a sequential workflow of inputs, analyses, and outputs between internal work groups. There are dependencies between system planning and design activities with asset management optimization that must be followed by financial planning activities. These activities are typically completed over the course of 2 years. Enbridge Gas expects it would require an additional 2 years to layer on energy planning considerations such as scenario

[86] EP Submission, page 4.
[87] Exhibit 1, Tab 10, Schedule 6, pages 39-40.

DEPRECIATION EXPENSE

DANIELLE DREVENY, MANAGER CAPITAL FINANCIAL PLANNING & ANALYSIS

1. The purpose of this evidence is to request OEB approval of Enbridge Gas's depreciation rates and depreciation expense for the 2024 Test Year. This evidence provides details of depreciation and amortization by asset group (storage, transmission, distribution and general) and plant account. The depreciation rates set out in this evidence are derived through a depreciation study completed by Concentric Advisors, ULC. (Concentric) for Enbridge Gas (Enbridge Gas Depreciation Study), which is provided at Attachment 1. Concentric has provided recommendations on depreciation and net salvage methodologies as well as asset useful lives. Enbridge Gas also requests approval for the alignment of 1) asset groups and plant accounts for the EGD and Union rate zones, 2) depreciation methodologies and 3) net salvage approaches for site restoration costs (SRC), all of which are included in the Enbridge Gas Depreciation Study and resulting depreciation rates. Finally, the evidence addresses the consideration of the potential impact of energy transition on the expected useful lives of Enbridge Gas's assets.

2. This evidence also addresses the OEB directive from EGD's 2014 to 2018 IRM Decision[1] to examine the issue of whether a segregated fund for SRC should be established and to undertake additional work regarding the discount rate used in the determination of SRC.

[1] EB-2012-0459, OEB Decision with Reasons, July 17, 2014, pp.56-58.

unregulated storage. Enbridge Gas engaged Ernst & Young LLP (EY) to assist management in its determination of the Company's harmonized unregulated storage allocation methodology. The aligned methodology for Enbridge Gas adopts the Union methodology of allocating general plant assets to unregulated storage. Further details, including impacts to 2024 Test Year depreciation expense are provided at Exhibit 1, Tab 13, Schedule 2.

3.5. Summary of Impacts of Harmonization of Depreciation Policies at Rebasing

33. Enbridge Gas is proposing a depreciation expense of $892 million for the 2024 Test Year. A comparison of the proposed depreciation rates and the provision for the 2024 Test Year is provided at Attachment 2. /u

4. Energy Transition Considerations

34. In developing the proposed depreciation rates, Enbridge Gas and Concentric considered the introduction of an Economic Planning Horizon (EPH) or truncation date to reflect the potential impact that energy transition could have on the economic life of Enbridge Gas's system.

35. Enbridge Gas and Concentric concluded that introducing an EPH is not appropriate at this time. As provided at Exhibit 1, Tab 10, Schedule 5, Section 3, there remains significant uncertainty around the impacts that energy transition could potentially have on Enbridge Gas's system. However, future depreciation studies may warrant the introduction of a regional or system wide EPH, as the energy transition unfolds and more information on the future utilization of Enbridge Gas's assets becomes available.

2021 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO NATURAL GAS PLANT IN SERVICE

Prepared for Enbridge Gas Inc.
October 2022

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
587.997.6489

The ELG procedure was specifically developed for use by rate regulated companies. The ELG procedure was popularized in a publication of the Iowa State University entitled “Depreciation of Group Properties – Bulletin 155” by Robley Winfrey in 1942. At the time of the publication of Bulletin 155, what is currently known as the Equal Life Group Procedure was at that time published as the “Unit Summation” Procedure. Initially, the use of the ELG procedure was somewhat limited because of the extremely large number of calculations that are required when this procedure is used. However, in the 1970’s and more so in the 1980’s this method became more popular due to the increased use of computerized software, rendering the number of calculations to be a non-issue. At that time, many regulated telephone companies adopted the use of the ELG procedure, including virtually all of the regulated telephone companies that were regulated by the Canadian Radio and Telecommunications Commission (CRTC). In the late 1980’s many other utility sectors began to adopt the use of the ELG procedure throughout North America.

The use of the ELG Procedure enhances the generational equity to all toll payers when all relevant costs are considered. Furthermore, use of the ELG Procedure provides ratepayers an enhanced matching of the depreciation expense component of the revenue requirement to the consumption of the service value of assets providing utility service. As indicated by Robley Winfrey in Bulletin 155, “the unit summation procedure of the present worth method is shown to be the only mathematically correct method”.

This study calculates the annual and accrued depreciation using the Straight-Line method and ELG procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to adjust the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.2 Economic Planning Horizon and Decarbonization

3.2.1 Concept of Economic Planning Horizon

The life of long-lived assets such as those comprising EGI’s system can be restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also and to a much greater extent, by economic forces of retirement. Specifically, the changing North American marketplace for natural gas demand and the rapidly emerging trend of decarbonization legislation may have a significant impact on the estimated service lives of the EGI system.

There are several factors affecting the economic viability of the EGI system. Long life assets, such as natural gas storage, transmission and distribution systems, are subject to a number of different forces of economic retirement, including changes in legislation constricting the use of carbon-based fuels.

The concept referred to with the terms “economic planning horizon”, “economic life”, or “truncation date” (each of which have similar meaning within depreciation literature) is one of the parameters that can be used to set depreciation rates that accurately reflect the annual consumption in service value. Appropriate depreciation rates also help to ensure that both long term intergenerational equity among customers and a reasonable opportunity for the recovery of investment are achievable.

The pipeline system will experience both interim and final retirement activity. Interim or ongoing retirements represent those retirements described by the interim survivor curve, which is commonly referred to as the Iowa curve. Terminal or final retirements represent those retirements described by the truncation of the interim survivor curve at the truncation date (or economic life). Interim retirements include retirements related to replacements that are primarily caused by wear and tear, deterioration, and technological obsolescence, i.e. the replacement of an item of equipment with a newer item with greater functionality. Terminal retirements include retirements related to the final abandonment of major components of the system caused by the economic obsolescence of the system. Such retirements are not expected to occur all at once. Rather, it is anticipated that there will be a relatively restricted period during which these major retirements will occur. In order to readily perform the mathematical calculations of average and remaining life, the timing of the terminal and final retirements is represented by a single point, the economic planning horizon (or life span date).

3.2.2 Decarbonization

On June 8th, 2016, the Office of the Ontario Premier Kathleen Wynne released its plan for a "low-carbon future" in its "Climate Change Action Plan". The action plan outlined Ontario's plan to begin phasing out natural gas for heating by providing incentives to retrofit buildings. This plan was replaced on November 29, 2018 with the Made-in-Ontario Environment Plan released by Premier Doug Ford. The Made-in-Ontario Environment Plan commits to reducing greenhouse gas emissions to 30 percent below 2005 levels by 2030.

EGI has responded to the Made-in-Ontario-Plan with a number of low carbon strategies, including a pilot program to test the blending of hydrogen, a voluntary RNG program, and the filing of a new DSM 2022-2027 Plan. The pilot program will provide EGI with a better understanding of the future use of hydrogen within the gas distribution system. These strategies will enable EGI to better plan for a lower carbon future.

In addition to the Made-in-Ontario Environment Plan, the Canadian federal government has passed a number of acts and regulations intended to bring Canada in line with Paris Accord. Prime Minister Justin Trudeau signed the Canadian Net-Zero Emissions Accountability Act on June 30, 2021. This act sets the goal of 2030 greenhouse gas emissions being 40-45 percent below 2005 levels by 2030. Further, there is the requirement that greenhouse gas emission goals be set for 2035, 2040, and 2045 at least ten years in advance. Ultimately, the goal is for Canada to attain net-zero emissions by 2050. It is noted that both the cities of Hamilton and Toronto have made net-zero commitments independent of federal or provincial mandates.

The federal government notes that the movement to hydrogen may be an important step in order to achieve a net-zero emissions target by 2050. The federal government has created a fund intended to increase production of low-carbon fuels, including hydrogen and renewable natural gas. The use of hydrogen and renewable natural gas may have a significant impact on the business of EGI in the foreseeable future.

3.2.3 Economic Planning Horizon Recommendations

While there is strong evidence that the future of natural gas in Ontario may be impacted by climate change legislation, it is still unknown to what extent this change will impact EGI's system. The introduction of hydrogen may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel. The same may be true of renewable natural gas or other low carbon fuels. However, it may also be true that the move from carbon based fuels necessitates a greater electrification, in which case there may be a life shortening impact on some or all of the EGI system.

The future growth and retirement programs of the EGI system may be significantly different than the retirement patterns witnessed in the past. While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. Consistent with the reduction in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050.

Common depreciation practice is to deal with the anticipated large scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations. However, at this time the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide indications of the changes in the utilization levels. Concentric views that additional study of the changes is required before the introduction of a Life Span date for the EGI system into the depreciation rate calculations. While such an introduction will cause a significant increase in the depreciation rate, Concentric notes that future depreciation studies of the EGI system may require the introduction of an EPH into the depreciation rate calculations. Concentric has attached Appendix 1 that shows the depreciation rate calculations using the same recommended depreciation parameters as the current study, with the introduction of a 2050 EPH. While Concentric is not recommending this move at this time, the calculations are provided as an example of what would be expected if a 2050 EPH were approved.

3.3 Estimation of Survivor Curves and Net Salvage

3.3.1 Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups*

Enbridge Gas focus on maintaining current levels of safety, reliability, and customer service, and that they wanted the Company to look at the long-term health of the system, spreading costs out evenly over time even if this approach would have an impact on rates.

37. At a high level, respondents had the opportunity to provide feedback on the Company's business plan objectives, climate change goals, and efforts to reduce GHG emissions from natural gas, all of which could introduce higher costs that would be passed on to customers. Across all customer segments, a clear majority of customers indicated they believe Enbridge Gas is taking the right approach.

38. At least two thirds of customers (general service and contract) supported the draft rate increase included in the workbook as a result of the draft plan. Generally, customers chose to spend more now to improve Enbridge Gas assets, such as replacing aging compressor stations and vintage steel pipelines, rather than delay, even though this would have an impact on their bills. Customers were also supportive of energy transition initiatives, agreeing the Company should actively invest in low-carbon solutions including energy efficiency technologies, hydrogen gas, RNG and carbon capture, utilization and sequestration (CCUS), as well as advancing research, development, and commercialization of low-carbon technologies.

39. Further detail on customer engagement is provided at Exhibit 1, Tab 6.

4. The Current Energy Transition Landscape

40. Over the past several decades, global governments have recognized that climate change is a shared problem that requires global action. Through the Kyoto Protocol and the Paris Agreement, countries have agreed to reduce GHG emissions

entering the atmosphere.

41. As provided at Exhibit 1, Tab 10, Schedule 3, the Government of Canada has committed to reducing GHG emissions by 40% below 2005 levels by 2030, and to net-zero emissions by 2050. Federal policies to achieve these targets have been developed and implemented, with the development of further policies underway.

42. The Government of Ontario has committed to reducing GHG emissions by 30% below 2005 levels by 2030 and provincial climate policy development and implementation is underway, with some policies already in place. A provincial panel has also been struck[12] to advise the Ministry of Energy on long-term energy planning in the context of this transition. The panel's goal is to keep energy rates low and provide market signals for the long-term development of Ontario's energy sector.[13]

43. To date, the provincial government has not set any GHG reduction targets beyond 2030, however, as Canada's second-largest emitting province, Ontario will need to achieve further GHG reductions if the federal government's ambitious net-zero target is to be achieved by 2050.[14]

44. Municipalities across Ontario are also increasingly taking action to address climate change within their boundaries. Primarily, this includes establishing plans to achieve municipally set targets and/or measures to mitigate climate change, while

---

[12] Government of Ontario. (2022, March 24). Order in Council 698/2022 https://www.ontario.ca/orders-in-council/oc-6982022.
[13] This is consistent with the October 21, 2022 Letter of Direction from the Minister of Energy to the Chair of the OEB, https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf.
[14] Government of Canada. (2022, May 26). Greenhouse Gas Emissions https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**3**	
DATE:	**July 17, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

demonstrate that the vast majority of the spend is focused on the sustainment of our existing assets and the percentage of dollars, you know, that go toward replacement of existing assets is a lower proportion then that meant to sustain. And barring that, of course, meeting the growth needs; so new pipelines to meet growth needs of the franchise.

So these are all areas that we believe can pivot if energy transition policies unfold in such a way that our growth forecast changes. And/or if, you know, the repair versus replace decision needs to be more granular, or more graduated, then some of these tools will allow us to do that.

MR. MONDROW: All right. Thanks for that, Ms. Giridhar.

In your current energy transition plan that is before the Board, there is no work on which assets are more likely to be underutilized sooner rather than later, the cost of retiring those assets, or avoiding new investments in them in the first place. There is no analysis of that sort in your current energy transition plan.

MS. GIRIDHAR: I think it is fair to say that, in our depreciation evidence, we have taken steps to ensure that we don't extend lives beyond what is the existing practice in at least one of the two legacy utilities. I think that that is an important step we are taking.

So, again, I think it is very akin to our safe bets approach that we want to have the right starting point. We don't want to make things any worse, any more uncertain, than they are. Like, that is the right starting point. We need to have processes in place so that we can evolve and pivot as changes happen and we are not static for the next five years. Those are the areas that we focused on in this application.

MR. MONDROW: Okay. So let me just ask that question again, and maybe you can supplement your answer and answer that question. My question was, you don't have any work in your current energy transition plan on assets that are more likely to be underutilized sooner rather than later and the cost of retiring those are avoiding new investment in them in the first place.

MS. GIRIDHAR: I thought I'd answered that question, Mr. Mondrow. Apologies if you are not convinced I did. The first thing is we don't yet at this point have a view on what assets, if any, would be retired sooner than we are currently planning for. Our current expectations are embedded in the depreciation study in terms of asset lives that we have proposed. To the extent that we may need to pivot in terms of repair versus replace decisions, we have introduced the EDIMP deferral account. And if I may just confer for a moment.

MS. WADE: And I would just maybe add to the end where we began with integrated energy planning, and so to be able to get to that level of granularity that you are noting in terms of which might have a shorter life or be underutilized, that really has to be done at a regional granular level in tandem with the electricity sector -- just repeat what we have said. I don't think we can contemplate the reduction in gas use without contemplating what will be replacing it.

MR. MONDROW: You haven't looked at which customers by class or by geography are more or less likely to leave the system sooner rather than later, nor the potential number of those customers that might leave the system. Is that correct?

MS. GIRIDHAR: I think it is fair to say until we understand what those customers are replacing the gaseous energy with it is hard to contemplate where that might occur.

MR. MONDROW: That is fine. But then the answer is, no, you haven't, and you have just given me the reason why. Correct?

MS. GIRIDHAR: Correct.

MR. MONDROW: Okay. Thanks.

There is no evidence other than the depreciation evidence, which I thought said we didn't consider the energy transition in the context of our depreciation policies at the moment, but you have given some different evidence, and we will come back to that with your depreciation panel, but subject to that there is no evidence that discusses regulatory mitigation tools that may be most useful to address the energy transition risks.

MS. GIRIDHAR: I do believe SEC 20 that you referred to did talk about accelerated depreciation at a future

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**4**	
DATE:	**July 18, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

Group compendium. I was hoping we could mark it as an exhibit.

MR. MILLAR: The exhibit is K4.2.

EXHIBIT K4.2: THREE FIRES GROUP COMPENDIUM FOR PANEL 1.

MR. DAUBE: On the compendium, please, I was hoping we could go first to page 3. Oh, I guess we have got -- exactly. Thank you. I believe this is a statement from Ms. Wade:

"And I think you will agree just generally," first paragraph, "that this evidence provides a description of he energy transition assumptions that Enbridge Gas incorporated into its forecasting."

Is that correct?

MS. WADE: That is correct.

MR. DAUBE: And it also describes how these forecasts affect Enbridge Gas' asset management. Is that correct?

MS. WADE: Yes, that is correct.

MR. DAUBE: Go to the next page, please. I believe you have stated, Ms. Wade, that, in the past, Enbridge's forecasts only considered climate policies that had already been implemented.

MS. WADE: That is correct.

MR. DAUBE: So, in other words, this is the first time that Enbridge has gone beyond existing policies and considered developing climate policies for the purposes of a rate-setting application. Is that correct?

MS. WADE: That is correct.

MR. DAUBE: Okay. If we go to page 8, I take it the company's position is that it is now prudent to incorporate energy-transition assumptions into company forecasts where there is reasonable certainty based on policy signals, market trends, and stakeholder feedback. Is that correct?

MS. WADE: That is correct.

MR. DAUBE: But the company's view remains that there is great uncertainty around the pace and nature of how energy transition will take place in Ontario. Is that right?

MS. WADE: That is correct.

MR. DAUBE: I assume you would also say that is the case in Canada more broadly. Correct?

MS. WADE: That is correct.

MR. DAUBE: And around the world?

MS. WADE: Yes.

MR. DAUBE: In that context, I believe it is your position that there is no hard and fast way that net zero will be achieved. Is that correct?

MS. WADE: That is correct.

MR. DAUBE: And you have agreed in the past that it is important for other pathways to be modelled in addition to the two scenarios from Enbridge's application?

MS. WADE: That is correct. I would say that we support and think that all of the pathway modelling that is being done, including that of the provinces is contributing to an understanding of how different permutations of inputs or assumptions can impact an outcome. And then I would just add, as I have briefly noted, moving down to that next regional level of modelling is of importance when looking at how it could impact the gas system or electric system specifically.

MR. DAUBE: That is right. So, within that, regional, and what you are saying is not just different pathways will it be important to model but different types of questions related to energy transition. Is that fair?

MS. WADE: Within the regional model, yes, that is fair. I would say that what we think would be valuable is to have both the electricity and the gas sector together talk about the inputs and assumptions that would go into a regional analysis.

MR. DAUBE: Part of the exercise there, I take you to be saying, is that these other modelling exercises will be able to examine, among other things, consequences on different groups within Ontario that these scenarios don't currently capture?

MS. WADE: That is correct.

MR. DAUBE: Can we go to page 19, please, my page 19. If we could go two more, please, so to page 3 of 3. That is right. Thank you. I think this is uncontentious: Posterity did not directly consider international policy developments and thinking as part of its analysis relating to codes and standards for retrofits and new construction. Is that right?

MS. WADE: Yes, that is correct. As noted there, the assumption is that Canada's energy efficiency regulations are influenced by international policy developments, but we did not look externally or internationally for other guidance.

MR. DAUBE: But, that qualifier, that is all going to be past-looking, no? So those are existing standards, and so, to the extent that they are capturing international developments and you are indirectly incorporating that, they won't be forward-looking; they will only look at the world as it existed at the time of implementation?

MR. TIESSEN: That is true for previous versions of the code, but I think we assume the same assumption for changes that are being made to future versions of the code, as well. So when we were looking at updates to NECB and NCB, the different tiers and the intention of provinces to adopt those codes, we are assuming those have also been influenced by codes outside of Canada.

MR. DAUBE: Now, you didn't contact them for the purposes of this report, did you?

MR. TIESSEN: We did not.

MR. DAUBE: So this is very indirect.

MR. TIESSEN: I agree with that.

MR. DAUBE: Now, if we go down the page a little bit, I believe Enbridge and Posterity have confirmed that they did not consider any international examples beyond the small number listed from the United States, on the question of non-price-driver fuel switching. Is that right?

MR. TIESSEN: Yes, that is correct, but I will also advantages with certain paths, create incentives in terms of various policy pathways. Is that fair?

MS. GIRIDHAR: We would agree with that statement, but we would also obviously be informed by what are the pre-existing conditions in terms of energy demand and energy supply in our existing energy systems in Canada.

MR. DAUBE: Of course. But with that pre-existing context, it is not only that these international developments are potentially the source for ideas --

MS. GIRIDHAR: Yes.

MR. DAUBE: ...or trends. They are also shaping similarly the environment that the Ontario energy landscape is going to have to integrate into, onto, draw from and so on. Fair?

MS. GIRIDHAR: Yes. I think a good example that I can think of right there is, you know, I think 20 years ago, if you went to Europe, you would find a lot of energy equipment would have sensors on it; elevators wouldn't simply keep running and, you know, lights would switch off and so on. And we see increased adoption of that, here. So I would definitely agree that, over time, we would try to take best practices from elsewhere.

MR. DAUBE: Now some of those international policy choices are likely to bring implications for Ontario companies in terms of their ability to export products. Is that a fair statement?

MS. GIRIDHAR: Yes.

MR. DAUBE: For example, if we could go to my page 23, which I believe is 25 for the reporter -- sorry, one more. I got my page wrong. I don't know how I can expect you to get yours right.

For example, you are aware that certain jurisdictions are examining the possibility of border carbon adjustments.

MS. GIRIDHAR: Yes, we are aware.

MR. DAUBE: And, in fact, the European Union has started to implement border carbon adjustments in certain sectors. Right?

MS. WADE: That is correct, yes.

MR. DAUBE: You will agree that the possibility has attracted some attention and some study among lawmakers in the United States?

MS. WADE: Yes.

MR. DAUBE: Would you agree that this is a developing policy instrument that appears to be adopted increasingly internationally, and has the potential to be adopted increasingly around the world?

MS. WADE: Sorry, just one moment. Sorry, yes, we would agree with that. And it will be informed by the carbon pricing programs that are in place as well within each of the jurisdictions, as noted in the article.

MR. DAUBE: If we go to page 29, if I am remembering what the math is -- sorry, my 27. I believe it is your 29. You agree with the statement from this report -- one paragraph down, please? -- that there is increasing momentum around the use of border carbon adjustments as countries move forward with the implementation of their domestic climate policy framework? As a general proposition, it sounds like you are agreeing with that.

MS. GIRIDHAR: Yes.

MS. WADE: Yes, that is correct.

MR. DAUBE: You will agree that instruments like a border carbon adjustment or other tariffs can affect the ability of Ontario companies to export to the jurisdiction that is putting them in place?

MS. GIRIDHAR: Correct.

MS. WADE: Yes.

MR. DAUBE: So when it comes to a border carbon adjustment, to the extent that Ontario or companies within Ontario remain emitters -- and I take the point about it gets complicated with carbon taxes and so on -- but instruments like a border carbon adjustment could affect their competitiveness?

MS. WADE: Yes, I would agree with that.

MR. DAUBE: Or even leave them uncompetitive in certain markets?

MS. GIRIDHAR: Yes, we would agree. Ask I think we also note that the Ontario government has identified the clean electricity credit mechanism. I think the most recent Powering Ontario's Growth plan showed the carbon intensity of the grids in certain competing jurisdictions in Canada and the U.S. So I think we can agree with that.

MR. DAUBE: But in terms of the materials that you have put before the Board in this application, consideration of the border carbon adjustment in Europe or and how they would reach that from a macro level. But I think you are asking more specifically by region, groups within those areas and how they would be affected. Is that correct?

MR. DAUBE: Yes. So more industry groups, for example. You know, how is the steel industry going to do, and so on.

MS. WADE: Yes, that is correct. We have looked at more from a business segment perspective, as opposed to down to a specific regional level.

MR. DAUBE: And we haven't mentioned, this but I think this flows. There is no analysis of the impacts for vulnerable customers.

MS. WADE: This modelling, yes, again, is done at provincial level. So the answer to your question is yes. I would have to find the page reference, but I think it does note within our evidence, and within the Guidehouse report, that this is going to be an important consideration in any pathway, in a diversified pathway. And the consumer choice element that we have also laid out, I think, is an important piece that would support ensuring that the vulnerable communities, or portions of the communities, would have choice so they are not unduly impacted.

MR. DAUBE: Okay. Now, I won't spend too much time on this because I think we have two pages in the record already on this, but, if you go to my pages 84 and 85. So I guess -- thank you.

You and I spoke about this at the technical conference. I think you agreed that that was more for the purposes of future modelling principles you would apply going forward. Right?

MS. WADE: That's correct, yes.

MR. DAUBE: And nothing is stopping the company from performing that analysis now. It is just that you thought other modelling was more relevant to the Board's consideration. Is that fair?

MS. WADE: I would say the caveat to that, that we have called out a few times, is that, to go down to that granular regional level and understand the impacts to all groups within that specific region, it would need to be done in tandem with the electricity sector to ensure that any assumptions we have made would align; say, for example, that they could take the load on their system.

MR. DAUBE: Okay. You acknowledged at the technical conference, at my page 85, that there could be greater impact to vulnerable communities if there are not policies that support reduced costs for those communities. Is that still your position?

MS. WADE: Yes, I would agree that, if that is not modelled and understood, then there could be impacts to those communities.

MR. DAUBE: And a similar position you have asserted on the question of what will the consequences be for remote Indigenous communities. Right?

MS. WADE: That is correct.

MR. DAUBE: Now, is it fair to say that the absence of more granular modelling, sector by sector, region by region modelling, makes it a whole lot harder to determine which assets in the future might be more likely to be retired?

MS. WADE: I think that is fair, yes. So our model, as we've noted, is one-node provincial, and, in order to understand the very specific impacts on our system, we would have to get down to a more granular and regional level.

MR. DAUBE: So, when we talk about safe bets, that is a huge gap, no?

MS. WADE: I don't think it is a huge gap in terms of the safe bets that we have put forward today. I think the safe bets that we are proposing recognize the piece that you're noting and are elements that we feel we should be moving forward with regardless of the fact that we don't have that information or because we don't have that information yet. So, for example, the integrated planning that is a safe bet, that would contribute directly to being able to address your question. I think the hydrogen grid study, for example, that would address your question as well, and a few of the other ones that we could go through. But I think it is important that we move forward with those safe-bet actions despite the fact that we don't yet have that information.

MR. DAUBE: Mr. Brophy touched on this -- oh, also no modelling on potential economic opportunity from any pathway, so on implementations of things like RNG development or carbon capture for specifically First

Nations in Ontario. Right?

MS. WADE: That is correct, yes. At this point in time, those have not been taken into consideration, and I guess just one more piece that I would add is critical to this regional analysis talked about is ourselves and the electric sector being at table, but so too will be the guidance provided by the province and policy direction. That would contribute to the work that we would do together.

MR. DAUBE: Mr. Brophy touched on this a little bit, so this is in some ways an expansion. You know, I think it is fair to say that there are a lot of moving pieces from a technology perspective and that that contributes to, I think, a lot of the uncertainty on pathways. That is me editorializing a little bit. The question here is: There is no modelling here on what happens if your assumptions specifically on access to RNG or hydrogen prove overly optimistic? Is that fair?

MS. WADE: I would say, within the modelling that we have done, we did some sensitivities on a number of the inputs or assumptions that we made. We did not model multiple sensitivities -- actually, just give me one moment. I am going to double check that. So, to confirm, we did not do any sensitivities on the volume of RNG and hydrogen. We did do a sensitivity on the cost of the electrolyzers. So, as we have noted there, there could probably be hundreds if not thousands of permutations of the study that we did, but, for those specifically that you

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2022-0200**	**Enbridge Gas Inc.**
VOLUME:	**8**	
DATE:	**July 25, 2023**	
BEFORE:	**Patrick Moran**	**Presiding Commissioner**
	Allison Duff	**Commissioner**
	Emad Elsayed	**Commissioner**

would pose to EGI. The company would also need to consider whether it could continue to make new investments under those circumstances, as EGI competes for capital internally within Enbridge, as well as externally.

MR. O'LEARY: Mr. Coyne or Mr. Dane?

MR. COYNE: I think we would like to add an investor perspective to that question, and that is, from an investor perspective, that would shift EGI's risk profile to a quasi-utility model and, in all likelihood, increase the cost of debt and equity capital for the company beyond anything we have considered in our analysis.

We are not aware of any North American distribution utility regulated on that basis. It would look more like a pipeline company, where investment recovery is at greater risk, and we know there that allowed returns are well above 10 percent for pipeline companies and equity ratios are well above 50 percent. So it would represent a fundamental shift in the view of the investment community toward how Enbridge is regulated.

MR. O'LEARY: Thank you, Mr. Coyne. So one final question to you, Ms. Ferguson. Do you have any concluding comments in support of the company's request for a increase in the equity thickness?

MS. FERGUSON: Yes, thank you, Mr. O'Leary. I would like to summarize as follows. An equity ratio of 36 percent is not commensurate with the risk associated with investments in natural gas transmission, storage, and distribution, including the risks of the ongoing energy transition.

EGI operates in the same economic, geographic, and regulatory environment as Ontario electric utilities, and has higher leverage. This difference in equity thickness between EGI and electric utilities in Ontario implies that electric utility business risk is higher than that of natural gas distribution utilities. That is clearly not the case, considering the vast and foundational impact energy transition has on natural gas distribution.

Although there are other regulatory tools that may mitigate the risk of energy transition, such as accelerating depreciation or implementing an economic planning horizon, which return invested capital at a faster pace, these tools do not address fundamental investor risk. They simply shrink the business faster.

Energy transition is so broad and foundational to a natural gas distribution business and has such vast impact on the operations of Enbridge that is unlike any other challenge that management is facing. Having an external party, in this case the government, tell the company that it will no longer be able to sell its product is a very different kind of risk facing the company today. The Board has also recognized this uncertainty in its report of the Board to Ontario's Electrification and Energy Transition Panel. At page 23, it states:

> "Electrification, the transition to renewable gases, carbon capture and storage, and hydrogen provide uncertainties that are unique to natural

gas distributors. These uncertainties give rise
to increasing risks that require natural gas
distributors to consider the role their resources
and infrastructure can play in a net-zero
future."

I would like to reiterate again that cost of capital is a forward-looking concept. It is insufficient to look at the past as indicative of what performance will be in the future. Investors understand that energy transition is transforming the risk of the environment under which local gas distributors are operating. The proposed increase in equity thickness is a modest step that will strengthen EGI's balance sheet to better manage through the transition and compete for capital on more equivalent terms with its Ontario and North American peers and is required as a requirement for meeting the fair return standard.

MR. O'LEARY: Thank you, panel. Those are my questions, and the panel is now, subject to any comments from the Commissioners, open for cross-examination.

MR. MORAN: Thank you, Mr. O'Leary. Mr. Mondrow, I think you are up. I believe you are going to take us past the lunch break, so, whenever you find a reasonable point to suggest a lunch break, we will be in your hands.

MR. MONDROW: Thank you, Sir. Is 12:30 the time you are considering? Okay. Very good. Thank you.

CROSS-EXAMINATION BY MR. MONDROW:

Good afternoon, witnesses. Nice to see you all in person and nice to see that you are taking those in energy transition plans, policies, and targets. The gathering and consideration of these insights support continuous improvement of Enbridge Gas's demand forecast, AMP, and IRP processes.

2.4. Gas Supply Planning

47. The Gas Supply Plan is based on annual volume forecasts that include both general service and distribution contract customer demand. Energy transition assumptions are implicit in the 2024 Gas Supply Plan through their inclusion in the 2024 volume forecast as provided in Section 1.2, and through the design day forecast which includes energy transition indirectly through the customer forecast as provided in Section 1.4. For more information regarding the Gas Supply Plan please see Exhibit 4, Tab 2, Schedule 1.

3. Finance and Regulatory Approaches

3.1. Introduction

48. This section provides details on how Enbridge Gas has considered energy transition in other elements of this rebasing application, including in the development of the revenue requirement and rate design proposals.

49. Energy transition poses a significant increase in the risks faced by natural gas utilities. Enbridge Gas has considered alternatives to respond to these increasing risks, including changes to the Company's depreciation rates to mitigate stranded asset risk, and changes to the Company's deemed equity ratio to address increased business risk. These alternatives are further discussed below.

3.2. Depreciation

50. Enbridge Gas's proposed depreciation rates and depreciation expense forecast for the 2024 Test Year are provided at Exhibit 4, Tab 5, Schedule 1. The proposed

depreciation rates are supported by a depreciation study conducted by Concentric Energy Advisors, Inc. (Concentric), which is provided at Exhibit 4, Tab 5, Schedule 1, Attachment 1.

51. In developing the proposed depreciation rates, Enbridge Gas and Concentric considered the introduction of an ‘Economic Planning Horizon’ (EPH) or truncation date to reflect the potential impact that energy transition could have on the economic life of Enbridge Gas’s system.

52. There is potential that climate change legislation, such as municipal or provincial plans to phase out the use of natural gas, could have a life-shortening effect on Enbridge Gas’s system. However, there is also the possibility that service lives could be lengthened or maintained if low-carbon fuels, such as hydrogen and RNG, are determined to be viable sustainable alternatives to natural gas. Also, as demonstrated in the P2NZ Study provided at Exhibit 1, Tab 10, Schedule 5, Attachment 2, and Exhibit 1, Tab 10, Schedule 5, Section 3, Enbridge Gas’s system will be a key contributor to achieving net-zero in the province.

53. Enbridge Gas and Concentric concluded that introducing an EPH is not appropriate at this time. There remains uncertainty around the impacts that energy transition could potentially have on Enbridge Gas’s system as discussed above. However, future depreciation studies may warrant the introduction of regional or system wide EPHs, as the energy transition unfolds and more information on the future utilization of Enbridge Gas’s assets becomes available.

54. If a diversified pathway to net-zero is not adopted in Ontario, Enbridge Gas would seek to introduce an EPH on its system to mitigate the risk of stranded assets. For illustrative purposes, if a system-wide 2050 EPH were to be implemented starting

2024, the 2024 Test Year depreciation expense would increase by $282 million[15], from $921 million to $1.2 billion. The depreciation study used to calculate this is provided at Exhibit 4, Tab 5, Schedule 1 Attachment 1.

3.3. Equity Thickness

55. The uncertainty around energy transition has significantly increased Enbridge Gas's business risk and is a major factor underpinning the Company's proposal to increase the equity thickness component of its deemed capital structure from 36% to 42%. The equity thickness proposal is provided at Exhibit 5, Tab 3, Schedule 1.

56. Enbridge Gas retained Concentric to perform an independent assessment of the reasonableness of the capital structure currently authorized by the OEB. The resulting report is provided at Exhibit 5, Tab 3, Schedule 1, Attachment 1, Enbridge Gas Inc. Common Equity Ratio Study (the Equity Ratio Study).

57. Enbridge Gas and Concentric concur that the Company's risk profile has increased significantly since 2012, the last time the OEB reviewed equity thickness for EGD[16] and Union[17]. In early 2013, the OEB concluded that new environmental policies at the time had not increased EGD's risks in comparison to 2007.

58. Since then, energy transition has become the most significant factor contributing to increased business risk for Enbridge Gas, as evidenced by findings in the Equity Ratio Study:

---

[15] Calculated using the depreciation rates from Enbridge Gas Depreciation Study (Exhibit 4, Tab 5, Schedule 1, Attachment 1).
[16] EB-2011-0354.
[17] EB-2011-0210.

ENBRIDGE GAS INC.
COMMON EQUITY RATIO STUDY

OCTOBER 17, 2022

CEADVISORS.COM

natural gas today."[90] Another California study noted that "RNG faces large technical obstacles."[91] A study conducted by Washington State University's Energy Program indicated that "adequate opportunities exist for RNG production equivalent to 3 percent to 5 percent of current natural gas consumption."[92] Oregon's Department of Energy identified 13 barriers to using RNG to reduce GHG emissions, including financial barriers (i.e., difficulties attracting capital), information barriers (i.e., due to unfamiliarity with the technology), market barriers (i.e., lack of vehicles and infrastructure), and policy barriers (i.e., Oregon-specific rules and statutes impeding RNG development).[93]

These preliminary studies regarding the viability of RNG do not necessarily mean that RNG is not a viable long-term solution. However, from an investor's perspective, pursuing such an uncertain pathway intrinsically carries risk. Further, as with the hydrogen discussion above, it is a risk that was not as meaningful at the time of the Company's previous equity thickness proceedings (i.e., 2012).

4. Risk Implications

The Energy Transition substantially affects nearly every aspect of the Company's business, from its growth prospects, to the capital projects it pursues, to its fundamental ability to offer investors the opportunity to earn a fair return on, and of, invested capital. Even though the Energy Transition will play out over many decades, it is now underway and it is materially increasing the Company's risk profile because of the long expected lives of most natural gas utility investments. For example, as Brattle recently noted:

> *The transition will affect gas companies' growth opportunities, cost recovery, and capital attraction. In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability. Utilities will need to recover their costs from a changing – and possibly shrinking – customer base. With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks. Heightened perceptions of business risk are increasing financing costs for gas utilities.*[94]

---

90 *Ibid*.
91 *Id*., at 33.
92 Washington State University Energy Program, "Promoting Renewable Natural Gas in Washington State: A Report to the Washington State Legislature," December 2018, at 1.
93 Oregon Department of Energy, "Biogas and Renewable Natural Gas Inventory SB334 (2017): 2018 Report to the Oregon Legislature," September 2018, at 43-45.
94 The Brattle Group, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 9.

Similarly, Moody's observed:

> *Although natural gas transportation and distribution companies continue to provide generally safe, reliable service while reducing emissions, there are ESG reputational risks associated with any hydrocarbon-based business, including financial governance policy risks around a higher cost of capital and lower asset returns over a multi-decade time horizon. Events like the August 2020 Baltimore explosion exact heavy social costs related to customer relations and public health and safety. Financial risks also stem from the likelihood of construction delays and greenfield project budget overruns, potential cancellations, regulatory fines and penalties for accidents, increasing debt obligations associated with gas infrastructure expansion and potential write-offs of stranded assets as the carbon transition progresses.*[95]

McKinsey examined the future for gas utilities under four alternative scenarios, and concluded:

> *These four scenarios, then, envision a wide range of outcomes. What's notable is that in three of them, natural-gas demand declines substantially. The only scenario with stable demand is the one in which renewable natural gas is developed—and this is by no means a sure thing. Clearly, gas LDCs need to prepare.*[96]

The sub-sections below discuss several specific ways in which the Company's risk profile has changed because of the Energy Transition.

a) *Volumetric Risk*

The opposition to natural gas threatens the Company's sales volumes through franchise renewal challenges, potential net-zero mandates, and increasingly stringent building codes or bans on new gas hook-ups. The Company has deferral and variance accounts that provide a degree of short-term insulation from this risk (insulation that will improve if the Company's SFV rate design proposal is adopted). However, in the long-term, investors are concerned that increasing costs recovered over declining volumes may create a "death spiral" scenario. As Brattle notes:

> *As states pursue degasification policies and homes convert to electric heating, utilities risk losing customers and load. Nationally, electric heating is outpacing gas heating adoption. Technology mandates and policy further accelerate the problem. Utilities will likely continue investing in their existing system for safety and reliability but need to*

[95] Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 2.

[96] McKinsey & Company, "Are US gas utilities nearing the end of their golden age?" September 2018, (https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/are-us-gas-utilities-nearing-the-end-of-their-golden-age).

> *recover those costs from a shrinking customer base. This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification. Up to $150–180 billion of gas distribution assets could be underrecovered as a result of the transition. This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.*[97]

Brattle also observes that the "transition will not occur at the same pace or magnitude across customer classes, which compounds cost recovery risks."[98]

Therefore, as discussed more fully in the volumetric risk section below, we conclude that the Energy Transition increases the Company's volumetric risk.

b) Operational Risk

Increasing opposition to natural gas makes it more difficult, costly, and time-intensive for natural gas distribution utilities such as the Company to construct and permit new facilities. Depending on the extent of this opposition, shareholders may bear increasing amounts of operational risks or cost overruns as critical infrastructure projects are delayed. As Moody's notes:

> *Long-term challenges to natural gas infrastructure are increasing. Natural gas is increasingly being called into question over environmental and greenhouse gas (GHG) emissions. Permitting difficulties related to new pipelines, local government mandates favoring electrification and state carbon reduction commitments raise operating risks and cost of capital.*[99]

This increasing opposition represents a marked change from the operating environment in 2012 (i.e., the Company's previous equity thickness proceedings). In 2020, the New York Times noted that oil and gas pipelines are "being challenged as never before as protests spread, economics shift, environmentalists mount increasingly sophisticated legal attacks and more states seek to reduce their use of fossil fuels to address climate change."[100] Setbacks experienced by the Atlantic Coast Pipeline, the Dakota Access Pipeline, and the Keystone XL oil pipeline were specifically cited as evidence that heightened opposition "represents a break from the past decade, when energy companies laid down tens of thousands of miles of new pipelines."[101] It was further noted that, even

---

97 Brattle, "The Future of Gas Utilities Series: Transition Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.

98 *Id*., at 15.

99 Moody's Investors Service, "Sector In-Depth: Shifting Environmental Agenda Raise Long-Term Credit Risk for Natural Gas Investments," September 30, 2020, at 1.

100 New York Times, "Is This the End of New Pipelines?" July 8, 2020, https://www.nytimes.com/2020/07/08/climate/dakota-access-keystone-atlantic-pipelines.html.

101 *Ibid*.

was recently resumed after receiving a recent round of funding),[155] and others. The OEB recognized that this increases forecast risk borne by utilities:

> *Competing utility companies would be incented to provide rates favourable to customers in order to be selected as the preferred proponent of the expansion project. The selected proponent would then be incented to maintain low rates in order to be attractive to potential customers which would in turn should [sic] increase its margins. A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs. The utility would bear the risk for that 10-year period if the customers they forecast did not attach to the system. At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected. The cost is absorbed into rates and paid for by other ratepayers.*[156]

We conclude that EB-2016-0004 moderately increases the Company's risk relative to 2012 in two ways: (1) it increases the Company's exposure to forecast risk, as noted by the OEB, and (2) it weakens the Company's growth prospects because it now faces increased competition from other utilities to serve currently unserved areas.

Regulatory Mechanisms

In EB-2011-0354, the OEB noted that regulatory mechanisms such as rate design and deferral and variance accounts "operate to protect Enbridge's revenues."[157] The OEB elaborated, finding:

> *Enbridge now collects a greater portion of its revenues from fixed charges than in 2007. Enbridge does not consider that this reduces risk. An Enbridge witness indicated that this change was made for purposes of reflecting cost causality more accurately. However, the Board agrees with the intervenors that this change also helps to mitigate risk. Distribution costs are largely fixed. If more of the costs are recovered through fixed charges, there is less revenue volatility related to volume changes, and less uncertainty that the fixed costs will be recovered. This mitigation is greater now than it was in 2007, since Enbridge's forecast for 2013 shows 51% of revenues collected through fixed charges, a significant increase over 33% in 2007. In addition, Enbridge has benefited from a growing customer base over which to recover its fixed costs. This means that Enbridge's revenues are now less dependent on volume than in 2007.*[158]

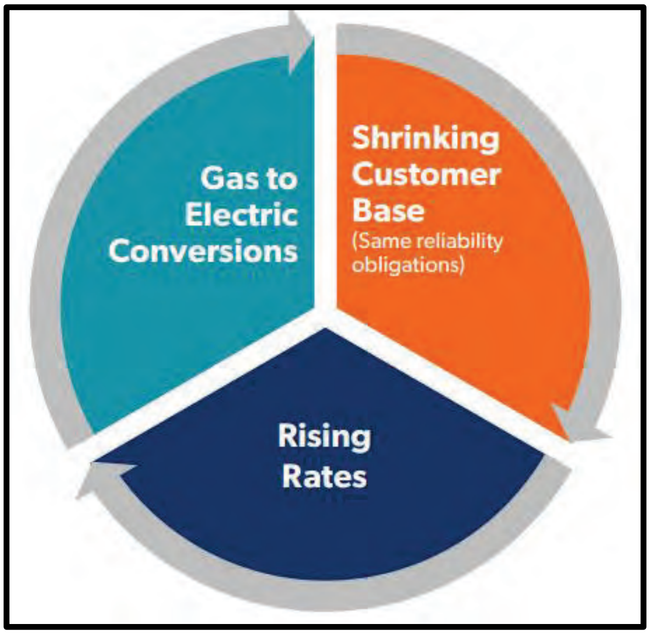
155 EB-2017-0260, Letter from Joel Denomy to Kirsten Walli, July 10, 2018.
156 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016, at 20.
157 EB-2011-0354, Ontario Energy Board Decision on Equity Ratio and Order, February 7, 2013, at 10.
158 EB-2016-0004, Ontario Energy Board Generic Proceeding on Community Expansion, Decision with Reasons, November 17, 2016, at 20.

We note that the Company is proposing a SFV rate design in this case. If approved, this proposal would further decrease the Company's exposure to volumetric risk. We note that the Company continues to benefit from regulatory mechanisms such as deferral and variance accounts that mitigate the potential financial impact of declining sales volumes (although these accounts may be discontinued if the Company's SFV proposal is approved). For these reasons, we conclude that the Company has regulatory mechanisms that mitigate the Company's volumetric risk in the near-term. However, as discussed in more detail in the following section, we conclude that the Company's long-term volumetric risk has increased.

"Death Spiral" Risks

Over the long-term, gas distribution utilities such as Enbridge Gas face the risk that they will lose customers and load to electrification and other energy sources. However, gas distribution utilities must continue investing in their systems in the short-term to maintain the safe and reliable provision of utility service. Together, those two factors mean it is possible that gas distribution utilities face what has been termed a "death spiral" whereby an increasing amount of cost must be recovered from a continually shrinking customer base. In a death spiral scenario, the resulting rate increases provide incentives to customers to leave the gas system, creating a negative feedback loop of rate increases and customer departures. Brattle created the following figure illustrating this scenario.

Figure 12: Brattle Illustration of Death Spiral Risks[159]



A future "death spiral" is far from certain, and we anticipate that the Company will work proactively to avoid such an outcome. However, it is possible. In 2020, residential customers accounted for approximately 57% of the Company's revenues but just 32% of its sales volumes.[160] If a meaningful portion of these customers switch to non-gas heating sources, whether due to technological advancements, environmental concerns, or policy mandates, costs will increase for the Company's remaining customers. Such a scenario could potentially spark a so-called "death spiral."

Due to the acceleration of declines in average use per residential customer, declines in the rate of customer additions, a relatively weaker economic growth outlook, the OEB's encouragement of competition, and the Energy Transition pressures, we conclude that the risk of a "death spiral" is higher today than it was in 2012. Further, while the Company benefits from a variety of ratemaking mechanisms that provide risk insulation in the short-term, regulation can do little to mitigate these longer-term pressures because this scenario is driven by economics, not regulatory pressures.

Conclusions

The Company's average use per residential customer has continued to decline since 2012, and its growth prospects today are weaker than they were in 2012. The Company had, and continues to

159 The Brattle Group, "The Future of Gas Utilities Series: Transitioning Gas Utilities To A Decarbonized Future," Part 1 of 3, August 2021, at 11.

160 Enbridge Gas Inc., Consolidated Financial Statements, December 31, 2020, at 14; and Company-provided data.

INDUSTRIAL AND SITES

Carbon Net Zero Strategy

Responsible Energy Management

Energy efficiency is the cornerstone of Stellantis' approach. The Company continues to improve the energy efficiency of its operations around the world, taking advantage of state-of-the-art energy management tools for its facilities. Efforts to implement decarbonized electricity on a broader scale are getting into gear, with ambitious projects on photovoltaic and wind parks which will operate on and off-site in Europe, North America and South America.

At the **Mangualde plant in Portugal, Stellantis recently announced the implementation of a photovoltaic solar energy capture project for self-consumption**. Once fully implemented, it will cover 31% of the facility's electricity needs, allowing the annual avoidance of 2,500 tons of CO2 emissions. In Zaragoza, Spain, the plant will generate 14,340 MWh per year thanks to a ground-mounted system of 34,800 solar panels. In Madrid, Spain, the facility's rooftop displays a 6.7-MWp solar on-site generation system, made by 15,000 solar panels that will cover over 30% of the factories energy needs, saving more than 8,000 MWh per year. Various other locations around the world also embrace solar power to provide self-produced green energy, including sites in France, India and Germany.

Zaragoza Photovoltaic Plant

Pioneering Real Estate Management

Stellantis pioneered new, flexible ways of working for its workforce that safeguard its employees as well as reduce real estate footprint at its facilities. The Company targets to cut emissions 75% by 2030 and its "New Era of Agility" (NEA) project contributes to this goal. NEA transforms Stellantis' working methods, with an average distribution of 70% of working time at distance and 30% on site for all employees whose activity allows it. The project allows Stellantis to be more agile and efficient while the Company continues to work to optimize its manufacturing footprint.

Further, in Poissy, France and Rüsselsheim, Germany, Stellantis plans to develop green campuses that will serve as role models for the rest of the facilities, as they embrace the low-carbon concept and extensive "greening" by 2025. Efforts include installing extensive solar panels on roofs, reducing footprints with modern vegetated sites, and using cutting-edge construction technologies to reduce CO2 emissions.

CARE

Dare Forward 2030

Care for the Planet, our Customers and our Employees

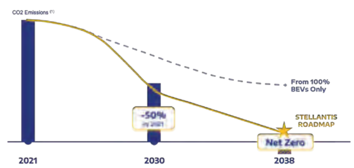
"Taking a leadership role in decarbonization is the best path to protect our company, our employees, and generations to come."

CEO, Carlos Tavares

Stellantis has the ambition to achieve **Carbon Net Zero by 2038** from well to wheel and throughout the entire supply chain, becoming the industry champion in climate change mitigation. As an intermediate target, we are working to cut our carbon emissions in half by 2030, compared to our 2021 levels.

And we are taking decisive steps forward in our **circular economy activities**, continuing the transformation from a cradle-to-grave to a cradle-to-cradle business model. This means development of a comprehensive, 360-degree business based on the traditional 4Rs – repair, reuse, reman and recycle.

The Path to Carbon Net Zero



(1) Includes Scopes 1 and 2 (-75% in absolute emissions – ton of CO2 equivalents) and Scope 3 (-50% in emission intensity – ton of CO2 equivalents per vehicle)

We aim to become **number one in customer satisfaction** for our products and services in every market by 2030. To achieve this objective, we are dedicating special attention to the complete end-to-end experience and inspiring actions throughout the value chain, with a focus on four key areas:

- reshaping the customer experience and reaching an unprecedented level of customer satisfaction with our electrified products and services
- using Big Data to reduce time to fix by 50%
- improving each customer touchpoint with a new holistic view of the customer journey
- always keeping the customer at the center of everything we do

Every Customer Counts. Every Journey Matters.

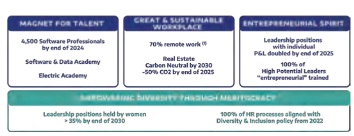
#1 means largest percentage of sales volumes in top quartile based on aggregate of syndicated survey data

Focus on the employee journey and becoming a great company to work for is also central to the Care pillar.

Diversity is one of our key strengths and we empower that diversity through meritocracy, rewarding and advancing individuals who exemplify leadership and an entrepreneurial spirit. This includes:

- our target of having at least 35% of leadership roles in the organization held by women by the end of 2030
- supporting our employees in accelerating their skills evolution and feeding their appetite to "dare forward" through reskilling and training programs
- strengthening our talent pipeline to embrace the Dare Forward mindset, doubling the number of leaders with direct profit and loss responsibility by the end of 2025

A Great Company to Work for



(1) For functions not directly linked to physical manufacturing and engineering activities

An Ambitious Decarbonization Strategy

The global race to cut emissions to zero is a vital step to tackle climate change, and Stellantis intends to be a front-runner. A huge undertaking possible only by reconsidering how we produce, consume, and move around. Transport has traditionally been heavily reliant on fossil fuels, which accounted for more than 90% of the sector's energy needs in 2020[(1)]. In the same year, it was the third main source of total carbon dioxide emissions, emitting over 7 Gigatonnes of CO_2[(2)]. As stated in the 2015 Paris Agreement, temperature increase needs to be limited to 1.5°C above pre-industrial levels to prevent the worst impacts of climate change and preserve our planet.

As the automotive industry accelerates change to avert climate and ecological threats, Stellantis' **Dare Forward 2030** strategic plan implements a pathway consistent with science-based recommendations to achieve this critical target. Through aggressive and clear targets, it sets out deep emission cuts to slash CO_2 in half by 2030[(3)], benchmarking our 2021 metrics, and achieve carbon net zero by 2038 with single digit percentage compensation of the remaining emissions[(4)].

(1) and (2) International Energy Agency

(3) Scopes 1-2-3 intensity - tons of CO_2 equivalents per vehicle

(4) The achievement is conditioned by key external enablers: decarbonized energy (based on Announced Pledges Scenario from International Energy Agency), and conducive public policies for BEV (charging infrastructure, purchasing incentives)

A Holistic Approach to Climate Change

*with single digit percentage compensation of the remaining emissions

"We took 2021 as a reference, which makes the trajectory of our ethical commitment very bold compared to peers. Taking a leadership role in decarbonization is the best path to protect our Company, our employees, and generations to come."

Carlos Tavares, Stellantis CEO

A Threefold Strategy to Reduce Our Carbon Footprint

Our push to net zero addresses all sources of greenhouse gas emissions, from **Vehicles** to **Supply Chain**, and **Industrial and Sites.** We identified **nine critical activities** to reduce our carbon footprint across Scopes 1, 2 and 3, implementing different **practices and technologies** that limit compensation to the bare minimum.

As the world is entering a hopeful new era for climate action, Stellantis is leading the industry's transition toward a carbon net zero future and expects all stakeholders to be aligned, starting with the clean energy supply.

Note: *Scope 1: GHG emissions that occur from sources owned or controlled by the Company; Scope 2: GHG emissions released from the generation of purchased energy consumed by the Company; Scope 3: GHG emissions that occur from sources not owned or controlled by the Company*

Vehicles

FIND OUT MORE ABOUT OUR VEHICLES STRATEGY

Supply Chain

FIND OUT MORE ABOUT OUR SUPPLY CHAIN STRATEGY

Industrial and Sites

FIND OUT MORE ABOUT OUR INDUSTRIAL AND SITES STRATEGY

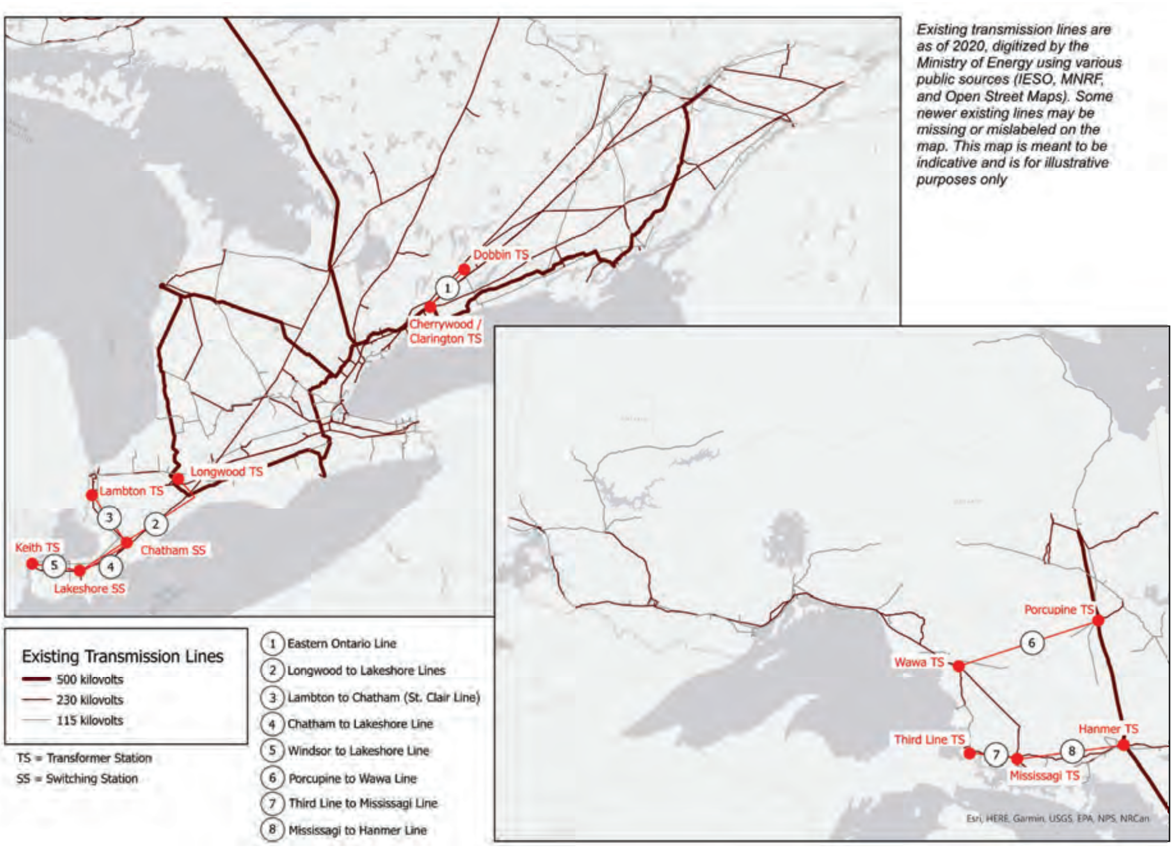
Powering Ontario's Growth

Ontario's Plan for a Clean Energy Future

ontario.ca/energy

Ontario

3.5 Transmission Expansion



High voltage transmission lines act as a high way that carries electricity from where it is produced to local distribution companies that deliver electricity to power homes and businesses. Electricity demand in the Windsor-Essex and Chatham areas is forecast to grow from roughly 500 megawatts (MW) of peak demand today to about 2,100 MW in 2035, which is almost equivalent to adding a city the size of Ottawa to the grid. This demand is primarily driven by rapid growth in advanced manufacturing, greenhouse agriculture and electric vehicle battery manufacturing, an economic success story for the region.

New electricity transmission infrastructure is the most cost-effective way to meet this growing electricity demand and continue to drive economic growth in the region. Last year, Ontario acted to ensure the efficient and timely development of five new electricity transmission infrastructure projects in Southwest Ontario. These transmission lines include:

- Chatham to Lakeshore Line
- St. Clair Line running from Lambton to Lakeshore
- Two Longwood to Lakeshore Lines and
- Windsor to Lakeshore Line

The government has issued an Order-in-Council declaring three transmission line projects as provincial priorities, streamlining the OEB's regulatory approval process for these lines so projects can be brought online earlier. The transmission projects between London, Windsor and Sarnia represent an investment of more than $1 billion and are proposed to be developed in phases through 2030. These transmission lines also present significant economic opportunities for Indigenous communities, through potential equity partnerships or other forms of participation.

Supporting Growth in Northeastern Ontario

Similar economic success stories are unfolding in other parts of Ontario, leading to the need for further transmission expansion. In the Northeast, electricity demand is forecast to grow rapidly over the next decade due to major industrial electrification initiatives, including Algoma Steel's planned conversion to electric steelmaking, as well as new mining opportunities. To meet these growing needs, the IESO has recommended three new transmission lines be in service by 2029 and 2030 in the Sault Ste. Marie and Timmins area, respectively.

Supporting Growth in Eastern Ontario and the Ottawa Region

Electrification and economic development in Eastern Ontario, especially Ottawa, are leading to growing electricity demands. To support continued growth, a new line is required between Peterborough and the Oshawa/Pickering area by 2029. This new line will address growing needs in these two regions, while also relieving constraints on existing lines to the Ottawa region.

To ensure these four new transmission lines are in service when they are needed, the Ministry will be launching consultations on a proposal to designate transmitters to start development work on these lines, and to declare these lines provincial priority projects. This includes targeted consultations with potentially impacted Indigenous communities. These proposed actions are the same actions that were taken to ensure that critical transmission infrastructure was built in a timely manner in the Southwest.

In parallel to these actions, the government is continuing its work with IESO to develop a formalized and competitive transmitter selection process for future lines. This process will replace Ontario's current approach to transmitter selection and provide a more timely, transparent, and predictable process for transmitters, stakeholders, and Indigenous partners. The IESO will announce new consultations on this framework in the coming months.

Indigenous leadership and participation will be critical for the successful development of linear infrastructure like transmission lines. There is a growing interest from Indigenous communities and organizations in building and operating transmission lines as a means o f advancing and supporting reconciliation with Indigenous peoples. Involvement in major transmission projects can provide Indigenous communities with economic development opportunities, including jobs, partnerships, and long-term revenue streams. Partnerships are also valuable for project developers whose projects may benefit from working closely with communities whose Aboriginal and Treaty rights may be impacted by the development.

Integrated Energy Planning

5.0 Introduction

Building the clean energy infrastructure necessary to power Ontario's future is a complex undertaking that requires the highest level of strategic energy planning and coordination.

Unlike previous governments, which viewed energy systems in isolation (refined petroleum products, natural gas, and electricity), the Ontario government is leading Canada in implementing an integrated energy planning process to ensure it is making the most cost-effective decisions necessary to prepare for a clean energy future.

This chapter describes the early planning process that began in 2021 with stakeholder and public consultation. The findings from that work have guided the government in creating the Electrification and Energy Transition Panel and commissioning the independent *Cost-effective Energy Pathways Study* as well as other initiatives that will inform planning, including at the IESO and OEB.

Building on the initiatives described in previous chapters, the next phase of the government's work will ensure that Ontario has the energy planning tools it requires to navigate the energy transition in a way that maximizes economic opportunities and the beneficial contribution of all parts of the energy system.

Roadmap to an Integrated Energy Strategy

The government began a review of the province's approach to long-term energy planning in 2021 to promote transparency, accountability, and effectiveness of energy planning decision-making, increase investment certainty, and ensure the interests of ratepayers are protected.

This review identified:

- The need for clear, high-level government policy direction;
- The importance of integrated, coordinated planning across energy sectors;
- A focus on independent, agency-led planning;
- The importance of independent planning oversight, with an emphasis on the role of the OEB as independent regulator; and
- The need for enhanced stakeholder and public participation.

As a result of this process, the government has taken steps to develop an integrated approach to meet Ontario's future energy needs. This has included:

- Bringing together the necessary technical advice to make informed decisions that are right for Ontario, including commissioning reports such as the *Gas Phase-Out Impact Assessment* and *Pathways to Decarbonization* by the IESO;

Integrated Energy Planning

5.0 Introduction

Building the clean energy infrastructure necessary to power Ontario's future is a complex undertaking that requires the highest level of strategic energy planning and coordination.

Unlike previous governments, which viewed energy systems in isolation (refined petroleum products, natural gas, and electricity), the Ontario government is leading Canada in implementing an integrated energy planning process to ensure it is making the most cost-effective decisions necessary to prepare for a clean energy future.

This chapter describes the early planning process that began in 2021 with stakeholder and public consultation. The findings from that work have guided the government in creating the Electrification and Energy Transition Panel and commissioning the independent *Cost-effective Energy Pathways Study* as well as other initiatives that will inform planning, including at the IESO and OEB.

Building on the initiatives described in previous chapters, the next phase of the government's work will ensure that Ontario has the energy planning tools it requires to navigate the energy transition in a way that maximizes economic opportunities and the beneficial contribution of all parts of the energy system.

Roadmap to an Integrated Energy Strategy

The government began a review of the province's approach to long-term energy planning in 2021 to promote transparency, accountability, and effectiveness of energy planning decision-making, increase investment certainty, and ensure the interests of ratepayers are protected.

This review identified:

- The need for clear, high-level government policy direction;
- The importance of integrated, coordinated planning across energy sectors;
- A focus on independent, agency-led planning;
- The importance of independent planning oversight, with an emphasis on the role of the OEB as independent regulator; and
- The need for enhanced stakeholder and public participation.

As a result of this process, the government has taken steps to develop an integrated approach to meet Ontario's future energy needs. This has included:

- Bringing together the necessary technical advice to make informed decisions that are right for Ontario, including commissioning reports such as the *Gas Phase-Out Impact Assessment* and *Pathways to Decarbonization* by the IESO;

- Establishing the Electrification and Energy Transition Panel (EETP) and commissioning an independent *Cost-Effective Energy Pathways Study*;
- Directing the OEB to consult and report back on options to modernize Ontario's regulatory framework to support the energy transition in a cost-effective manner; implement clear guidance to LDCs to enable them to upgrade their distribution systems in preparation for electric vehicle and increased DER adoption; and to report back on distribution sector resiliency, responsiveness, and cost efficiency; and,
- Ensuring ongoing proactive planning by the IESO with support from sector entities and stakeholders.

These actions are the foundational steps the government is taking as it prepares to develop an integrated energy strategy based on additional consultation and input from the energy sector, Indigenous and local communities, and the public.

5.1 Electrification and Energy Transition Panel

Electrification and the energy transition are intensifying, driven by significant growth in electric vehicles and by corporate environmental and sustainability decisions. Electricity generation resources and transmission can take five to 15 years to develop, so early planning is increasingly critical as electricity demand growth accelerates. For these reasons, in April 2022, the Minister of Energy announced the creation of the Electrification and Energy Transition Panel (EETP) to help the government prepare Ontario's economy for electrification and the energy transition and take the necessary steps now to ensure we have the energy infrastructure to support the growing demand for clean energy.

While long-term electricity planning is important, fuel-switching will also play a key role in Ontario's evolving clean energy mix. Understanding where this is likely to occur, through integrated energy planning, Ontario will be empowered to make smart decisions that will further support lowering energy bills and create a more predictable and competitive investment environment.

The EETP will identify strategic opportunities and recommend necessary planning reforms to support emerging electricity and fuels planning needs in the context of the broader transition to a clean energy economy.

Comprised of chair David Collie and members Professor Monica Gattinger (University of Ottawa) and Chief Emerita Emily Whetung-MacInnes, former Chief of Curve Lake First Nation, the panel will advise the government on high-value short, medium and long-term opportunities in the energy sector. This includes opportunities to:

- Enable investment and job creation in Ontario by keeping energy rates low;
- Create a more predictable and competitive investment environment;
- Build on the government's work to meet energy needs and ensure a reliable, affordable and clean electricity supply; and
- Strengthen Ontario's long-term energy planning process by better coordinating the fuels and the electricity sectors.

"Growing Ontario's economy will require growing our supply of clean energy. The Board is glad to see the Electrification and Energy Transition Panel moving forward with a strong mandate and expert members to inform a cost effective, competitive transition. This builds on the government's timely action to invest in energy storage, build Canada's first grid-scale SMR, and grow our hydrogen industry."

- Jan De Silva
President & CEO, Toronto Region Board of Trade

Energy Transition and Electrification Panel Themes

The EETP is exploring five key themes to inform discussions with stakeholders, Indigenous communities, and the public and guide recommendations in its final report:

1. **Energy Planning:** Improving long-term, integrated energy planning between the electricity and fuels sectors, exploring topics such as roles and responsibilities for the province and energy agencies and options to optimize energy demand and decarbonize future energy supply systems.

2. **Governance and Accountability:** Improving energy sector governance such as potential changes to agency mandates or regulatory frameworks and new performance metrics for the province and energy agencies for a successful transition.

3. **Technologies:** Improving regulatory and other frameworks and addressing barriers to core energy technologies and fuel types in energy and other sectors such as buildings, housing, transportation, industry and agriculture. Reducing barriers to low-carbon fuels, distributed energy resources and hybrid-heating solutions will be explored.

4. **Community and Customer Perspectives, Affordability and Energy Sector Objectives:** Balancing energy system costs, energy reliability and climate objectives while considering the rights of Indigenous communities, and the public interest. How citizen and customer choice and perspectives should be considered through the energy transition will be explored.

5. **Facilitating Economic Growth:** Identifying opportunities to advance economic development as it relates to the energy sector and the transition. Opportunities to improve Ontario's participation in green global supply chains and foster cross-sector collaboration in energy-intensive sectors, such as mining, steel and automotive sectors, while maintaining a cost-effective and low carbon electricity supply will be explored.

Cost-effective Energy Pathways Study

To support the work of the EETP and provide key inputs into long-term energy planning, the provincial government has commissioned an independent Cost-effective Energy Pathways Study to understand how Ontario's energy sector can support electrification and the energy transition.

This study will take an integrated, multi-fuel approach to optimize technological options to prepare the energy system for electrification and the energy transition.

The Panel, the *Pathways to Decarbonization* report, the *Cost-effective Energy Pathways Study* and other research together with ongoing consultation with stakeholders and the public will help the government make strategic decisions for the future of Ontario's energy system.

5.2 Low-Carbon Fuels

While much of the public focus has centred around electrification and meeting the province's electricity needs, exciting and innovative advances in low-carbon fuels continue to provide sustainable options that in some cases may provide a more cost-effective pathway to reduce emissions in the province's broader energy sector:

- Renewable Natural Gas (RNG) - is a pipeline-quality gas that is the product of the decomposition of organic matter that after processing is fully interchangeable with conventional natural gas. RNG is commonly collected from waste facilities, sewage treatment plants and green bin programs. Further details can be found in Chapter 1.

- Synthetic Natural Gas (SNG) – is a pipeline-quality gas that is produced through the Sabatier process in which methane and water are produced from a reaction of hydrogen and carbon dioxide. If low-carbon hydrogen is used, SNG can reduce the carbon intensity of the natural gas system.

- Ethanol – is a renewable fuel made from various plant materials (often corn). Gasoline in Ontario is blended at varying percentages to reduce the carbon intensity of the fuel and reduce air pollution.

- Renewable Diesel – is a fuel made from fats and oils, such as soybean oil or canola oil, and is processed to be chemically the same as petroleum diesel. Renewable diesel can be blended with petroleum diesel or can completely replace it to reduce the carbon intensity of the fuel.

- Biodiesel - is similar to renewable diesel but not chemically the same as diesel. It is made from vegetable oils, animal fats and recyclable restaurant grease and can be blended with petroleum diesel in limited quantities.

- Hydrogen – Depending on how it is produced, hydrogen has the potential to be a low-carbon fuel and can be blended with natural gas in limited quantities to lower the carbon intensity of the fuel.

5.3 Distribution System Innovation

Until recently, Ontario's electricity grid has been constructed to provide one-way flows of electricity generated at large power plants and transmitted lengthy distances to places where electricity is consumed. While large generators like nuclear and hydroelectric facilities at the bulk system level will continue to play an essential role serving as Ontario's electricity system backbone, the emergence of new tools, including DERs, at the local level is transforming the way families, businesses, and communities meet their energy needs. While DERs can increase the complexity of distribution planning, they also promise a broad range of benefits to consumers – from greater customer choice, improved system resilience and flexibility, to cost avoidance and large capital deferrals. Recognizing the important role these innovative technologies and business models will play in a clean energy future, in 2020, the Ontario government made "facilitation of innovation in the electricity sector" a new guiding objective for the OEB. OEB's 2022 System-Wide Electricity Supply Mix data indicates that roughly five per cent of Ontario's total annual generation comes from embedded DERs that send electricity to the grid and are quantifiable by LDCs and the IESO. Taking into consideration other demand side tools like EVs, smart thermostats and behind the meter (BTM) battery energy storage systems (BESS), IESO's DER Potential Study indicates that Ontario has an estimated DER capacity of 10,000 MW.

As more and more customers adopt BTM technologies (e.g., rooftop solar; BESS) to save money and take control of their electricity bills, much of this innovation will happen at the local distribution level. This requires Ontario's 59 Local Distribution Companies to modernize operations to keep pace with and enable customer connections and enable customer choice.

The government recognizes Ontario's regulatory framework can present barriers to testing innovative pilot or demonstration projects that show clear potential to support cost reduction or decarbonization objectives. To address this issue, the government made amendments to the *Ontario Energy Board Act, 1998* that allow the OEB to exempt proponents that wish to undertake innovative projects from various licence requirements on a time-limited basis. The government is considering additional steps to empower the OEB to issue exemptions from additional legislated or regulated requirements for innovators.

These changes will facilitate innovative pilot or demonstration projects that have the potential to benefit customers, the energy sector and the broader economy and support the transition to a more sustainable and renewable energy future.

Additionally, as customers seek new ways to participate in the energy transition, their relationship with LDCs is also changing, resulting in increasing expectations for LDCs to play a greater role connecting and integrating customer side solutions in new, varied, and concurrent opportunities, both safely and efficiently. Recognizing the grid must be there for customers when they need to "plug-in", the government will consider conceptual models that will facilitate customer participation and r educe system costs.

For instance, a distribution system operator (DSO) model – responsible for coordinating DERs at the distribution system level - could operate a local market, akin to what the IESO operates at the bulk level today, providing local distribution services. These services, such as capacity, increased power quality, and non-wire alternative services, could result in increased reliability and lower costs for customers. A DSO could also facilitate electricity trading among homes and businesses.

Allocating the roles and responsibilities for DERs in the future should aim to maximize benefits for consumers. To this end, both the IESO and the OEB will continue to work with LDCs to explore these and other opportunities to innovate and meet the needs of customers – safely, affordably, and reliably – along with the clean energy objectives of the province.

"Long-term energy planning gives businesses the predictability they need to invest and grow with confidence in Ontario. An integrated approach recognizes that clean electricity and low-carbon fuels will both contribute to a reliable, sustainable, and affordable energy system in the province. Ontario's Electrification and Energy Transition Panel is an important step towards a competitive energy transition."

- Rocco Rossi
President and CEO of the Ontario Chamber of Commerce (OCC)

5.4 Strengthening Ontario's Resiliency to Extreme Weather

In recent years Ontario has experienced an increase in extreme weather events. More significant climate shifts are predicted in the coming decades, which will increase the frequency of heat waves, heavy precipitation and flooding, ice and windstorms, wildfires, and similar events.

Disruptions to the energy sector caused by extreme weather create significant financial and safety risks for Ontarians — Electricity in particular, as most of the infrastructure is above ground is at risk in severe weather events.

The Ontario government is acting to protect the province's electricity grid from the impact of extreme weather as demand continues to grow due to electrification, economic growth, and the increasing reliance by families on electricity for transportation and home heating.

In October 2022, the Minister of Energy directed the OEB to launch consultations on proposals to improve the reliability of Ontario's electricity grid in the face of increasing severe weather. The OEB will provide advice to the Minister in Summer 2023 which will include best practices to ensure Ontario is best positioned to continue to provide reliable electricity to Ontario families and businesses. Best practices may include things like increasing grid redundancies, ensuring materials and equipment are on hand in elevated risk areas and technological advances that can help predict outages and support recovery from outages.

Powering Ontario's Growth

For the first time since 2005, demand for electricity in Ontario is rising thanks to strong economic growth, electrification, and population growth.

To meet this demand the province is embarking on an ambitious, multi-pronged approach to secure a clean energy future for our province, the economic engine of Canada.

As outlined in this report, meeting this challenge will require major investments in clean energy, including new nuclear generating stations, new transmission, new pumped hydroelectric storage, and other infrastructure needed to maintain and build our clean electricity advantage.

And these investments will pay dividends for the people of Ontario. With a reliable and affordable supply of clean energy we can power Ontario's growth.

And we are already seeing results with historic investments in EV and EV battery manufacturing as well as clean steel production which are bringing jobs to communities across the province.

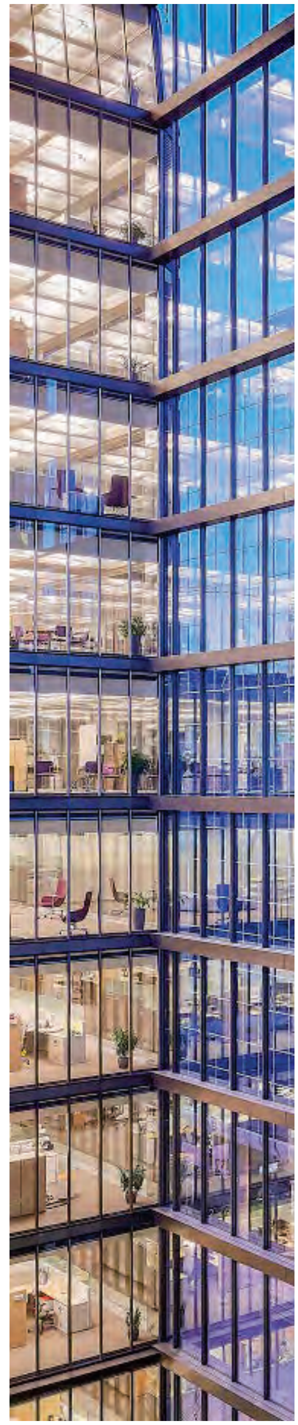
Building the next generation of clean electricity generation will make Ontario even more attractive for investment as we offer the certainty businesses are looking for. That includes the certainty that the clean power will be there to power the next major international investment, the new homes being built across the province and growing industries and sectors.

Unlike previous governments that viewed energy systems in isolation, this government is developing an integrated energy strategy that will meet Ontario's needs in 2050 and beyond.

BANK OF CANADA
BANQUE DU CANADA

Staff Working Paper/Document de travail du personnel—2023-27

Last updated: May 29, 2023



An Investigation into the Effects of Border Carbon Adjustments on the Canadian Economy

by Y.-H. Henry Chen,[1] Hossein Jebeli,[2] Craig Johnston,[2] Sergey Paltsev[1] and Marie-Christine Tremblay[2]

[1]Massachusetts Institute of Technology

[2]Financial Stability Department, Bank of Canada

*Corresponding author: hosj@bankofcanada.ca

DOI: https://doi.org/10.34989/swp-2023-27 | **ISSN** 1701-9397

Acknowledgements

We are grateful for comments and suggestions from Madanmohan Gosh, Miguel Molico Nicholas Rivers, and comments received from participants of the 2022 Canadian Economics Association Annual Meeting and the 2022 Bank of Canada Annual Conference. All remaining errors are our own. The views presented in this paper are those of the authors and do not represent the Bank of Canada's position.

Abstract

This paper examines how border carbon adjustments (BCAs) may address the unintended consequences of uncoordinated global climate action, focusing on the economic implications for Canada. We investigate these implications under different BCA design features and by considering a coalition of countries and regions that adopt BCAs. We find that BCAs, in the form of import tariffs, reduce Canada's carbon leakage to the rest of the world and improve its domestic and foreign competitiveness when Canada is part of a coalition of countries and regions that implement BCAs that includes the United States. We show that these results may change if Canada imposes BCAs on a different set of sectors than the rest of the coalition or includes export rebates and free emissions allowances to firms. When the United States is not part of the coalition, we show that Canada's carbon leakage increases, domestic competitiveness dampens and foreign competitiveness improves. Compared with a case where no countries have BCAs, welfare improves in Canada if revenues from BCAs, in the form of import tariffs, are transferred to households. This finding holds regardless of the United States' participation in the coalition.

Topics: Climate change; International topics; Trade integration
JEL codes: C68, F1, H2, Q5, Q37

Résumé

Notre étude examine comment les ajustements carbone aux frontières peuvent pallier les conséquences imprévues d'une action pour le climat non coordonnée à l'échelle mondiale, plus particulièrement les incidences économiques pour le Canada. Nous étudions ces effets en fonction de diverses caractéristiques des ajustements carbone et en tenant compte d'une coalition de pays et de régions les adoptant. Nous constatons que les ajustements carbone aux frontières, sous la forme de droits de douane, réduisent les fuites de carbone du Canada vers le reste du monde et améliorent la compétitivité intérieure et étrangère du Canada lorsqu'il fait partie d'une coalition de pays et régions comprenant les États-Unis qui mettent en œuvre ce type d'ajustements. Nous démontrons que les résultats peuvent changer si le Canada impose des ajustements carbone dans un ensemble de secteurs différents de ceux du reste de la coalition, ou s'il inclut des ristournes d'exportation et des allocations gratuites d'unités d'émission aux entreprises. Nous montrons que lorsque les États-Unis ne font pas partie de la coalition, les fuites de carbone du Canada augmentent, la compétitivité intérieure diminue et la compétitivité étrangère s'améliore. Si l'on compare avec une situation où aucun pays n'a de mécanisme d'ajustement carbone aux frontières, le bien-être s'accroît au Canada si les revenus découlant de ces mesures, sous la forme de droits de douane, sont transférés aux ménages. Cette conclusion reste valide peu importe si les États-Unis font partie ou non de la coalition.

Sujets : Changements climatiques; Intégration des échanges; Questions internationales
Codes JEL : C68, F1, H2, Q5, Q37

1. Introduction

In 2015, 196 countries around the world adopted the Paris Agreement with a goal to limit global warming to well below 2 degrees Celsius, and preferably to 1.5 degrees Celsius, compared to pre-industrial levels (UN 2015). Under the Paris Agreement, countries are expected to pledge climate action and submit their plans as National Determined Contributions (NDCs) every five years to the secretariat of the United Nations Framework Convention on Climate Change (UNFCC). As of late 2022, 166 countries have submitted new or updated NDCs, covering an estimated 94.9% of the total global emissions in 2019 (UNFCCC 2022).

The NDCs are based on an approach whereby individual countries pledge their climate actions at the domestic level.[1] These pledges create variations in climate policy across countries, including in terms of policy ambition (e.g., reflected in differences in emission reduction levels or the corresponding carbon prices) and sectoral coverage. A key implication of this is an uneven global playing field, leading to an erosion of the global competitiveness of sectors in countries implementing more stringent climate actions. Another implication, key for climate change, is carbon leakage—namely when climate policies in a country may cause increases in emissions in countries with weaker policies.[2]

Border Carbon Adjustments (BCAs) have been proposed as a mechanism to mitigate the drawbacks from global policy fragmentation. BCAs are intended to complement existing domestic climate policies by allowing countries to pursue and achieve their climate targets while limiting carbon leakage and the erosion of global competitiveness resulting from countries pursuing less stringent climate policies. BCAs may take the form of an import charge and sometimes rebates on exports. In the case of an import charge, BCAs may include a charge on imported goods, typically reflecting the difference in carbon pricing between trading partners and considering the emission intensity of the imported good. In the case of export rebates, domestic sectors exposed to carbon pricing in the home country may receive a financial transfer to preserve their global competitiveness. Likewise, export rebates can be calculated based on the regional differences in carbon pricing and reflecting the emissions intensities of the exported goods.

There is increasing momentum around the use of BCAs as countries move forward with the implementation of their domestic climate policy frameworks. For example, the Government of Canada initiated public consultations exploring the use of BCAs for a variety of fossil fuel and emissions-intensive trade-exposed (EITE) sectors, which account for more than 70% of Canada's exports.[3] Similarly, the European Union (EU) has recently started to implement BCAs across a subset of EITE sectors.[4]

Against this backstop, this paper examines the role played by BCAs in addressing the unintended consequences associated with uncoordinated global climate action. The analysis focuses on Canada-

[1] For instance, Canada's latest NDC pledge is to cut its emissions by 40% to 45% below 2005 levels by 2030, with an additional commitment to achieve net-zero emissions by 2050.
[2] See Paltsev, 2001, and Babiker, 2005.
[3] These sectors include oil and gas, mining, food and beverage, wood, pulp and paper, chemicals, petroleum and coal products, motor vehicles and parts, primary and fabricated metals, plastic and rubber products, aerospace products and parts, non-metallic mineral products, and transportation of natural gas (Government of Canada 2021).
[4] Council of the European Union, 2022.

specific implications on carbon leakage, domestic and foreign competitiveness (measured as changes in market shares), and welfare (measured as changes in equivalent variation[5]). We investigate these implications under different BCA design features and in consideration of the countries adopting BCAs. To help frame country participation, and consistent with related papers in the literature, we take a coalition versus non-coalition approach.[6] The coalition represents a group of countries pursuing and achieving their climate actions as set out under their respective NDCs. In this paper the coalition comprises Canada, the United States, the EU, Japan, Korea, and Mexico. The non-coalition represents a group of countries assumed to not achieve their NDCs, though they follow their policies and measures in place in 2022 (i.e., their baseline path). This framework also enables us to analyze the implications for Canada when its major trading partner, the US, is not in the coalition. The role of BCAs on the Canadian economy is indeed heavily dependent on whether BCAs are applied in the US, and the degree with which the US pursues climate action.[7]

This paper offers the following contributions to the literature. First, it provides a quantification of Canadian economic impacts resulting from BCAs. Focusing on a country like Canada helps shed light on the role played by the carbon content of a country's traded goods, the role these play in domestic production supply chains, and who the country trades with. Second, the paper considers different BCA design features and the interaction of BCAs with other policies that may also play a role in addressing carbon leakage and competitiveness matters. Specifically, our analysis accounts for the impact of existing regimes in Canada and the EU that are offering free allowances (compliance credits at no charge) to firms to assist them in meeting their greenhouse gas (GHG) emissions limits.

We find that when Canada is part of a broad coalition of BCA-implementing countries, including the US, BCAs, in the form of import tariffs, reduce Canada's carbon leakage and improve its domestic and foreign competitiveness. In addition, when the import tariff revenues are transferred to households, BCAs are welfare improving. We show that these results may differ when the BCA scheme considers differences in sectoral coverage, the addition of export rebates, and Canada's existing regime of free allowances to firms through the output-based pricing system. When the US is not part of the coalition, we show that Canada's carbon leakage increases. While domestic competitiveness is dampened, we show improvements in foreign competitiveness. Independent of whether the US participates in the coalition, the analysis finds that BCAs (only in the form of import tariffs, not export rebates) are welfare improving for Canada in comparison to the case where there are no BCAs.

While important, several challenges were not considered in the present analysis. With regard to compliance with the World Trade Organization (WTO), trade between countries will be exposed to different levels of adjustments, creating concerns BCAs could be in violation of the non-discrimination clause. However, some have argued that since a common mechanism would be used in determining

[5] Economic welfare impacts are reported as Hicksian equivalent variation in income, which denotes the amount necessary to add to (or subtract from) the benchmark income of the representative consumer so that she enjoys a utility level equal to the one in the counterfactual policy scenario on the basis of ex-ante relative prices.
[6] See Bellora and Fontagne, 2022.
[7] About 56% of Canada's imports in EITE sectors in 2020 come from the US (based on the authors calculations from the MIT-EPPA model, described in the following section).

these adjustments, varying BCAs by trading partner might not, on its own, violate this principal (Bellora & Fontagne 2022). Yet other aspects of BCA design create WTO compliance concerns, including discrimination based on foreign countries' emissions intensities, ensuring BCAs reflect the full spectrum of climate change mitigation policies beyond just carbon prices, the redistribution of revenues generated by BCAs, and concerns over the potential rebates to industry.

Beyond the WTO, there are additional challenges to the implementation of BCAs. For one, the introduction of BCAs could trigger retaliation by relevant trading partners, confounding the economic impacts. In Canada, questions remain whether BCAs would be compliant with existing free trade agreements, including the United States-Mexico-Canada Agreement (USMCA).[8] In addition, Canadian provinces have led the development of carbon pricing schemes, and imposing additional tariffs as a BCA measure at the federal level would be another challenge (Cosbey et al. 2021).[9] Conscious of the many limitations of implementing BCAs, this paper focuses on a set of illustrative scenarios intended to shed light on their potential economic impacts in Canada.

The paper is organized as follows. Section 2 reviews the research related to BCAs. Section 3 outlines the modelling framework used in this study. This section also provides a detailed description of how embodied emissions, BCAs, carbon leakage, and competitiveness are calculated, as well as an overview of the scenarios considered for the analysis. Section 4 presents the results of our analysis, considering various BCA design features (sectoral coverage, export rebates, interaction of BCAs with free allowances) as well as the implications for when the US is out of the coalition. Concluding remarks follow.

2. Relevant research

The literature examining BCAs has focused on carbon leakage, international competitiveness, and economic efficiency and welfare.[10] In terms of carbon leakage, the literature argues for two main channels. The first is the competitiveness channel, where carbon-intensive sectors reduce their domestic production because of higher operating costs associated with domestic climate policies, while production by sectors in countries facing less stringent climate policies increases, thereby increasing their emissions. The second is the fossil fuel price channel, where the decreased demand for fossil fuels

[8] Lilly et al., 2022 shows that while a carefully designed Canadian BCA could be both WTO-legal and permissible under Canada's major trade agreements, serious political and economic challenges are likely to arise.

[9] In addition, our study is silent on some of the macroeconomic implications of imposing BCAs, such as changes in exchange rates. This is examined in McKibbin et al., 2018.

[10] Our results are generally aligned with what is found in the literature at the global level. First, BCAs can improve global cost-effectiveness by partially transferring carbon pricing via trade flows to trading partners without emissions pricing policies. However, the magnitude of the efficiency gains may be limited due to the small fraction of emissions abroad (those that are imported in covered goods) that can be targeted, and foreign EITE industries may also reroute part of their exports to other non-regulated markets (Bohringer et al. 2012). Furthermore, the impact of BCAs on economic welfare has been investigated, with Winchester (2017) arguing that US welfare is lower when it met its Paris pledge as compared to when it faced BCAs but did not regulate GHG emissions—concluding that BCAs will not be effective in enforcing climate commitments in the US. Import adjustments on embodied carbon applied by richer, industrialized countries may also shift some of the burden of emissions pricing to poorer, developing countries. Such equity concerns can be addressed by returning the revenue from carbon import adjustments to paying countries or using it for technology transfer and international climate finance (Bohringer et al. 2022).

driven by abating countries puts downward pressure on the price of fossil fuels in world markets, which further increases their use and emissions in countries with less stringent climate policies. The consensus in the literature is that BCAs are moderately successful at reducing carbon leakage (Winchester et al. 2011).[11]

Studies that have looked at the competitiveness dimensions of BCAs generally find that BCAs modestly impact production losses or market share of domestic EITE sectors in favour of countries with weaker climate policies (Bohringer et al. 2012, Fouré et al. 2016). Several analyses using computable general equilibrium models have shown that significant output losses occur in energy-intensive sectors when a domestic climate policy is enacted (e.g., cap-and-trade or carbon price), and that BCAs are insufficient to counteract the impacts of the other policies (Burniaux et al. 2010; Mattoo et al. 2009, Winchester et al. 2011). Burniaux et al. (2010) attributes this to the fact that energy-intensive industries are affected primarily by the contraction of the overall market size that comes from carbon pricing, rather than by losses accruing to the international competitiveness channels. Similarly, Aldy and Pizer (2015) argue that most domestic production loss stems from energy price increases and reduced overall consumption rather than the loss of competitiveness in its product markets. Monjon and Quirion (2011) analyzed European climate policy and found that a decrease in EU production of energy-intensive products can be expected, but mainly due to a reduction in European demand rather than a shrinking global market share.

The efficacy of the EU's BCA scheme has been analyzed in Bellora and Fontagne (2022). Using a dynamic general equilibrium model, the authors simulate various BCA schemes consistent with the EU's proposed plan that covers non-fossil-fuel emissions-intensive sectors. The authors find the proposed plan is effective in reducing carbon leakage, but only partially effective in mitigating competitiveness losses. The authors argue that BCAs push up the domestic price of carbon, leading to increased prices for intermediate products used in downstream sectors. The authors further investigate the impacts of the design of BCAs as they relate to WTO rules and find that, while BCAs are most effective when constructed to discriminate against export markets, they indeed run the risk of violating WTO rules.

3. Modelling framework

3.1 General equilibrium model

We employ the MIT Economic Projection and Policy Analysis model (the MIT-EPPA model), which is a recursive-dynamic general equilibrium model representing the world's economy across several

[11] The 29th study by the Energy Modeling Forum (EMF), which considers a 20% emissions reduction in the industrialized world (countries listed in Annex 1 of the Kyoto Agreement), found that the BCAs for EITE industries reduce leakage rates by about one-third (Bohringer et al. 2012). In the reference scenario in Bohringer et al. (2012), leakage rates range between 5% and 19% with a mean value across all models of 12%. BCA is effective in reducing leakage. Leakage rates under BCA range between 2% and 12% with a mean value of 8%. Thus, the carbon-based import tariffs and export rebates to EITE products reduce the leakage rate on average by a third compared to the reference scenario with uniform emission pricing only. Analysing 25 studies, Branger and Quirion (2014) show that in the majority of the cases, the leakage ratio reduction due to BCAs stands between 1 and 15 percentage points. Their meta-regression analysis shows that all parameters being constant in the meta-regression analysis, the ratio drops by 6 percentage points with the implementation of BCAs.

countries/regions and sectors relevant for the consideration of climate policy design and BCAs (Chen et al. 2022a). An important characteristic of the MIT-EPPA model is the representation of links among sectors through each firm's use of domestic and imported intermediate inputs. Purchases of intermediate inputs are captured in input-output tables calibrated in the base year to aggregated data from the Global Trade Analysis Projection dataset (Aguiar et al. 2019). For each sector, these tables list the value of output produced and the value of each input used, which can be linked to physical quantities (e.g., tonnes of coal).[12] Further details on the MIT-EPPA model can be found in Appendix A, including the regional and sectoral representations used in this paper.

For the assessment of BCA impacts, we enhance the MIT-EPPA model in several dimensions. First, we disaggregate the energy-intensive sector in the MIT-EPPA7 model into three subsectors (i.e., iron and steel, cement, and other energy-intensive industries). Second, we use dynamic emission intensities in calculating embodied emissions. Third, the model now treats oil as a heterogenous globally traded commodity. Finally, we introduce a representation of BCAs in the form of import charges and export rebates.[13] The following subsections expand further upon some of the key assumptions and calculations in our analysis of BCAs, with additional information on the MIT-EPPA model provided in Appendix A.

3.2 Embodied emissions

Embodied emissions, which are important for the analysis of BCAs, refer to the total life cycle emissions associated with the production of a good. One can think of this as representing both the emissions directly associated with the production of end products plus any emissions passed through the supply chain. The ability for the MIT-EPPA model to capture links across sectors enables a detailed tracking of both direct and indirect emissions embodied within end products. Embodied emissions are therefore a function of the direct emissions and indirect emissions of producing a good, given as:

$$e_i^r = d_i^r + \sum\nolimits_j e_j^r \cdot \alpha_{ij}^r \cdot \delta_j^r$$

where e_i^r is the embodied emissions in good *i* produced in region *r*. The first term on the right-hand side is the direct emissions of production of good *i* in region *r*, given as d_i^r. The second term on the right-hand side is the indirect emissions embodied in input *j* used to produce good *i*, where α_{ij}^r refers to the input j per unit of good i, and δ_j^r is the share of j sourced domestically. Re-arranging this equation allows one to solve a system of n equations with n unknowns e_i^r:

$$e_i^r \cdot (1 - \alpha_{ii}^r \cdot \delta_i^r) - \sum\nolimits_{j \neq i} e_j^r \cdot \alpha_{ij}^r \cdot \delta_j^r = d_i^r$$

3.3 Border carbon adjustments

BCAs primarily take the form of import tariffs, and sometimes rebates on exports. In the case of import tariffs, BCAs may include a charge on imported goods based on their emissions intensity or embodied emissions. The import tariff is represented as an ad valorem tariff, calculated as follows:

[12] For example, the coal power sector will use inputs of capital and labour and outputs from the coal mining sector along with other intermediate inputs to produce electricity.
[13] More details of these changes will be presented in subsections 3.2-3.3.

$$\tau_i^d = \frac{\left(CP^d - CP^o\right) \times e_i^o}{p_i^o}$$

where CP^d and CP^o are the carbon prices in the importing and exporting region, respectively, e_i^o is the tonnes of carbon dioxide (CO_2) emissions embodied in each unit of good *i* in the exporting country, and p_i^o is the unit price of good *i* exported from region *o* to region *d*. Carbon prices in the model are represented by shadow prices. These prices are calculated endogenously in the model and represent what could be a broad range of climate policy actions needed to meet the emission reduction targets specified for each region/country.

In the case of export rebates, domestic sectors exposed to carbon pricing in the home country may receive a financial transfer to preserve their global competitiveness. When export rebates are considered in this paper, the export rebate is calculated as follows:

$$R_i^o = \frac{\left(CP^o - CP^d\right) \times e_i^o}{p_i^o}$$

Some of the import tariff rates and export rebates calculated based on these definitions are presented in Figure 9 and Figure 10 in Appendix B.

3.4 Carbon leakage and competitiveness definitions

Carbon leakage is defined as the amount of domestic emission reductions that gets offset by the increases in emissions abroad. To measure carbon leakage, one can compare emissions changes in the non-coalition countries with those in the coalition countries as follows:

$$Carbon\ leakage\ rate = \frac{Emissions_{NCOA}^{policy} - Emissions_{NCOA}^{baseline}}{\left|Emissions_{COA}^{policy} - Emissions_{COA}^{baseline}\right|} \times 100$$

where COA refers to coalition countries, NCOA refers to non-coalition countries, baseline refers to the baseline scenario, and policy refers to scenarios where at least some countries pursue more ambitious climate policy as compared to the baseline (NDCs for COA and baseline for NCOA). The denominator is represented as an absolute number to represent leakage based on how much non-coalition countries emissions change given the reduction in emissions in coalition countries. For example, an 8% leakage ratio implies that 8% of the emissions reduction achieved in coalition countries is offset through increased emissions in non-coalition countries.

In this study, foreign competitiveness is defined as the change in a country's export market share in total global exports. Domestic competitiveness in turn is measured for each sector *i* and is calculated as follows:

$$Domestic\ market\ share_i = \frac{Production_i - Exports_i}{Domestic\ supply_i}$$

where we have:

$$Domestic\ supply_i = Production_i - Exports_i + Imports_i$$

3.5 Free emissions allowances

Other climate policy measures, including in the EU and Canada, are also aimed at addressing the potential for carbon leakage and competitiveness loss associated with the relative stringency of their climate policies. The scenarios constructed as part of this analysis were developed considering the role of such policies, namely, the role of free allowances.

To safeguard the competitiveness of industries covered by the EU's Emissions Trading System (ETS), industrial facilities deemed to be exposed to significant risk of carbon leakage receive a higher share of free allowances compared to other industrial facilities. One of the main components of the EU's Carbon Border Adjustment Mechanism (CBAM) is the progressive phasing out of free allowances under the ETS over a ten-year period.[14] As of 2026, when the CBAM will come into effect, free allocations to European emitters will be gradually reduced by 10% per year, with the system fully replacing the free allowances by 2036. As stated by the European Commission, the CBAM is an alternative to free allocation, and as such the two measures should not overlap.[15]

In Canada's federal output-based pricing system (OBPS), registered industrial facilities are exempt from the carbon pricing scheme for fuel purchases but are required to pay for the portion of their emissions that exceed their annual facility GHG emissions limit.[16] Specifically, the OBPS establishes emission intensity performance standards for regulated industries, and using those standards, GHG emission limits are calculated for facilities based on their annual economic production. Facilities are issued compliance credits up to their annual GHG emissions limits at no charge. Facilities that exceed their annual limit may purchase additional compliance credits from facilities with surplus credits, acquire verified offset credits from elsewhere (e.g., verified GHG mitigation projects in other jurisdictions or non-regulated sectors), or purchase compliance credits from the government. Over time, stringency

[14] The CBAM was applied from 1 January 2023 with a transitional period until the end of 2026, and European Parliament believes it must be fully implemented for the above-listed sectors of the EU ETS by 2032. Sectors that are included under EU's ETS phase 3 (2013–20) are power stations, oil refineries, coke ovens, iron and steel plants, cement clinker, glass, lime, bricks, ceramics, pulp, paper and board, aluminium, petrochemicals, ammonia nitric, adipic and glyoxylic acid production, CO_2 capture, transport in pipelines and geological storage of CO_2, and aviation. For more details see EU ETS Handbook. The corresponding sectors in the EPPA model that receive the free allowances are iron and steel, cement, other energy-intensive industries, and electricity. Sectors that are included under CBAM are iron and steel, cement, fertilizer, aluminium, electricity generation, organic chemicals, plastics, hydrogen, and ammonia. For more details see European Commissions documentation on CBAM.

[15] https://ec.europa.eu/commission/presscorner/detail/en/qanda_21_3542

[16] Under the OBPS that is designed for industrial emitters with GHG emissions of 50,000 tonnes CO_2e or greater, a facility's annual emission limit would be calculated by multiplying the facility's total annual production by the applicable emission intensity performance standards for its activities. Each facility would pay for any GHG emissions that exceed its limit at a rate of $10 per tonne of CO_2e in 2018, rising by $10 per year, up to $50 per tonne of CO_2e in 2022. Sectors covered under the OBPS include oil and gas production, mineral processing, chemicals, pharmaceuticals, iron and steel, mining and ore processing, lime and nitrogen fertilizers, food processing, pulp and paper, automotive, electricity generation, and cement. For each of these sectors a benchmark emission intensity is specified in the policy, which can be found in Canada's Output-Based Pricing System Regulations (see Government of Canada 2019). These sectors correspond to the following sectors in the EPPA: oil and gas, cement, iron and steel, other energy-intensive industries, other manufacturing industries, food, and electricity.

levels can be increased by adjusting emission intensity performance standards to allow for fewer GHG emissions per unit of production and by increasing the price of compliance credits.[17]

3.6 Scenarios

To examine the effects of BCAs on the Canadian economy, we take a coalition versus non-coalition approach, where coalition countries represent a group of countries that are assumed to pursue and achieve their climate ambitions as set out under their respective NDCs. The non-coalition countries are assumed to follow current policies in place in 2022 as outlined under stated and current policies and targets.[18] The time horizon chosen for this study is until 2030. We select this time horizon given our interest in examining the contemporaneous impacts of BCAs on key indicators. Also, the NDCs generally cover this period.

To determine coalition countries, we follow Bellora and Fontagne's (2022) approach in assuming that countries with existing and mature domestic carbon pricing schemes are credible in their efforts to achieve their climate objectives as outlined in their NDCs. Based on the Carbon Pricing Dashboard developed by the World Bank, 18 countries and regions had national carbon pricing systems in 2021: Argentina, Canada, Chile, Colombia, the EU, Iceland, Japan, Kazakhstan, Korea, Mexico, Montenegro, New Zealand, Norway, Singapore, South Africa, Switzerland, United Kingdom, and Ukraine. Of these countries, Canada, the EU, Japan, Korea, and Mexico are distinct regions in the MIT-EPPA model (see Figure 8 in Appendix A). As such, these countries and regions are retained in our analysis. Further, to draw attention of the role played by Canada's main trading partner, the US, we first assume that the US is in the coalition. This assumption will be relaxed, enabling the comparison of results when the US is out of the coalition.[19]

We developed three main scenarios, which are outlined in Table 1. Under the first scenario, the *baseline scenario*, emission targets are aligned with the current climate policies for all countries/regions, though they are considered insufficient to achieve the emission reduction targets. In the second scenario, the *uncoordinated scenario*, coalition countries/regions pursue and achieve their NDCs,[20] while the non-coalition countries/regions continue along their baseline path. Contrasting the uncoordinated and baseline scenarios allows us to shed light on the consequences of a lack of global climate policy coordination.

[17] While such allowance systems allow domestic carbon-pricing schemes to both change relative prices and incentivize decarbonization, they alleviate the economic pressures on carbon-intensive industries, mitigating the consequences of the domestic policy design.

[18] Renewable shares are one of these targets, which are plotted in Figure 11 in Appendix C for some of the regions.

[19] For results related to the consequences of unilateral policy design and the number of countries implementing emissions reduction commitments, see Reinaud 2008, Bohringer et al. 2012.

[20] The emission targets of the coalition countries/regions under NDC are outlined in Table 6 in Appendix C.

Table 1 Scenario description

Scenarios	Coalition	Non-coalition	BCA design	BCA imposed	Free allowances	Sectoral coverage
1) Baseline	Baseline	Baseline	-	-	No	-
2) Uncoordinated	NDC	Baseline	-	-	No	-
2a) Uncoordinated with allowances	NDC	Baseline	-	-	Yes	-
3) Allowances + BCA (partial coverage | tariffs only)	NDC	Baseline	Imp tariff	Coalition	Yes	Partial

Coalition = Canada, US, EU, Japan, Korea, and Mexico
Non-coalition = all other countries
NDCs = nationally determined contributions
Baseline = current policies
Full = sectoral coverage refers to cement, coal, food, gas, iron and steel, oil, other energy-intensive sectors, other manufacturing sectors, and refined oil
Partial = sectoral coverage excludes fossil fuels and only includes cement, iron and steel, other energy-intensive sectors, and other manufacturing sectors

We also consider another version of the *uncoordinated scenario* that examines the implications of free allowances, introduced in section 3.5. Building on the *uncoordinated scenario*, the *uncoordinated with allowances scenario* (Scenario 2a in Table 1) assumes that specific sectors in Canada and the EU receive free allowances according to a constant portion of what they pay under the respective carbon pricing schemes. To determine what fraction of facilities receive these free allowances, we examined data from the EU's ETS and Canada's OBPS. In the case of the EU, over the period 2013–20, 57% of the allowances on the ETS were auctioned, while the remaining 43% were freely allocated to sectors deemed to be exposed to a risk of carbon leakage.[21] Based on this information, when considering scenarios that include free allowances, we assume in the MIT EPPA model that the EU's sectors that are regulated under the ETS receive free allowances equivalent to 43% of their carbon price costs.[22] For Canada, based on facility-level 2019 emissions data, 32% of Canadian emissions were on average from facilities emitting GHG emissions of 50,000 tonnes CO_2e or greater per year and fell under the OBPS.[23] We assume these Canadian facilities receive free allowances equivalent to 32% of their carbon price costs.[24]

[21] See Bellora and Fontagne 2022.
[22] For the EU, these sectors are iron and steel, cement, other energy-intensive industries, and electricity generation. For Canada, these sectors correspond to oil and gas, cement, iron and steel, other energy-intensive sectors, other manufacturing sectors, food, and electricity.
[23] To calculate this number we leveraged the facility-reported greenhouse gas data and provinces' total GHG emissions from National GHG inventory reports. Considering jurisdictions that either have their own OBPS, a cap-and-trade system, or fall under the federal OBPS system, in 2019, on average, 32% of Canada's total GHG falls under this system.
[24] This assumes that the OBPS emission intensity benchmark for each sector is the same as the average emission intensity of the sector in the model. In addition, total payment of the firms that have emission intensity higher than the sector's benchmark is equal to what the firms who are below the benchmark receive in that sector, resulting in no payment by sector in total. Since the MIT-EPPA model is at the sector level, we cannot model the heterogeneity within sectors in this paper to study the effects of the OBPS with more accuracy. Therefore, we assume that a representative firm of a sector included in the OBPS and the EU's ETS receives a fraction of what it pays under carbon pricing, and that fraction is the same as the share of emissions that fall under the OBPS. This means sector *i*, which is included in the OBPS and the EU's ETS, receives $R_i = \beta \times CP \times e_i$, where β is the fraction of emissions that fall

Under the third scenario, coalition countries/regions impose BCAs on imports from the non-coalition countries/regions. We call this third scenario the *Allowances + BCA (partial | tariffs only) scenario.* In this scenario, BCAs take the form of import tariffs (no export rebates) and are imposed on a partial set of emissions-intensive sectors (i.e., cement, iron and steel, other energy-intensive sectors, and other manufacturing sectors). We first study the case where BCAs are imposed on only this partial set of EITE sectors. The *Allowances + BCA (partial | tariffs only) scenario* also assumes the inclusion of free allowances. Finally, under all scenarios, revenues raised from imposing BCAs (from the import tariffs) are redistributed back to households via lump-sum transfers.[25] Given our interest in examining whether the design of the BCA scheme matters, we later explore the effects of expanding sectoral coverage, adding export rebates on top of import tariffs, and the interplay of free allowances and BCAs.

4. Results

4.1. Impacts on carbon leakage, competitiveness, and welfare

Table 2 shows the cumulative impacts on carbon leakage, domestic and foreign competitiveness, and welfare (measured as changes in equivalent variation) of the different scenarios over the 2020–30 period and relative to the baseline. Under the *uncoordinated scenario*, around 6.1% of Canada's emission reductions are offset by increases in emissions outside of Canada.[26] In addition, Canadian producers lose 0.43 percentage points of their domestic market share and 0.05 percentage points of their foreign market share due to the stricter climate policies that they face. This scenario also shows that welfare declines by 0.67 percentage points.

under these policies, CP is national carbon price, and e_i is the emission level of the sector (which is a function of its production level).

[25] BCA revenues can also be used to reduce distortionary taxes (McKibbin et al. 2018). Allocation of BCA revenues to the exporting countries is another option that can avoid shifting the burden of BCAs to developing countries (Bohringer et al. 2012; Fischer and Fox 2012). In fact, returning the BCA revenue to the paying countries or using it for technology transfer and international climate finance would likely improve a BCA regime's chance of success in meeting GATT's exception requirements by helping to demonstrate the BCA's environmental objectives (Cosbey et al. 2019, Bohringer et al. 2022). In this study, given the model limitations in terms of labour or capital distortionary taxes and to avoid implications of international transfers, we assume revenues raised from the import tariffs are redistributed back to households via lump-sum transfers.

[26] In this study, since countries/regions are constrained to reach their emission targets in 2030, emission variations are expected to be lower than those studies that do not impose constraints on emissions. For example, see Ecofiscal Commission (2016), which calculates Canada's leakage rate to be around 20%.

Table 2 Cumulative impacts over the 2020–30 period relative to baseline

Scenarios	**Carbon leakage rate** (percentage)	**Domestic market share** (percentage point change)	**Foreign market share** (percentage point change)	**Welfare** (percentage changes in equivalent variation)
2) Uncoordinated	6.10	-0.43	-0.05	-0.67
2a) Uncoordinated with allowances	4.38	0.12	-0.03	-0.78
3) Allowances + BCA (partial | tariffs only)	-1.07	0.52	0.04	-0.71

When introducing free allowances, Canada's carbon leakage is reduced from 6.1% to 4.38%. Free allowances also bring down the costs of production, improving competitiveness both domestically (0.55 percentage point change) and internationally, albeit at a lower level (only 0.02 percentage point change). Despite the introduction of free allowances, welfare declines further due to deadweight losses associated with this form of support.[27]

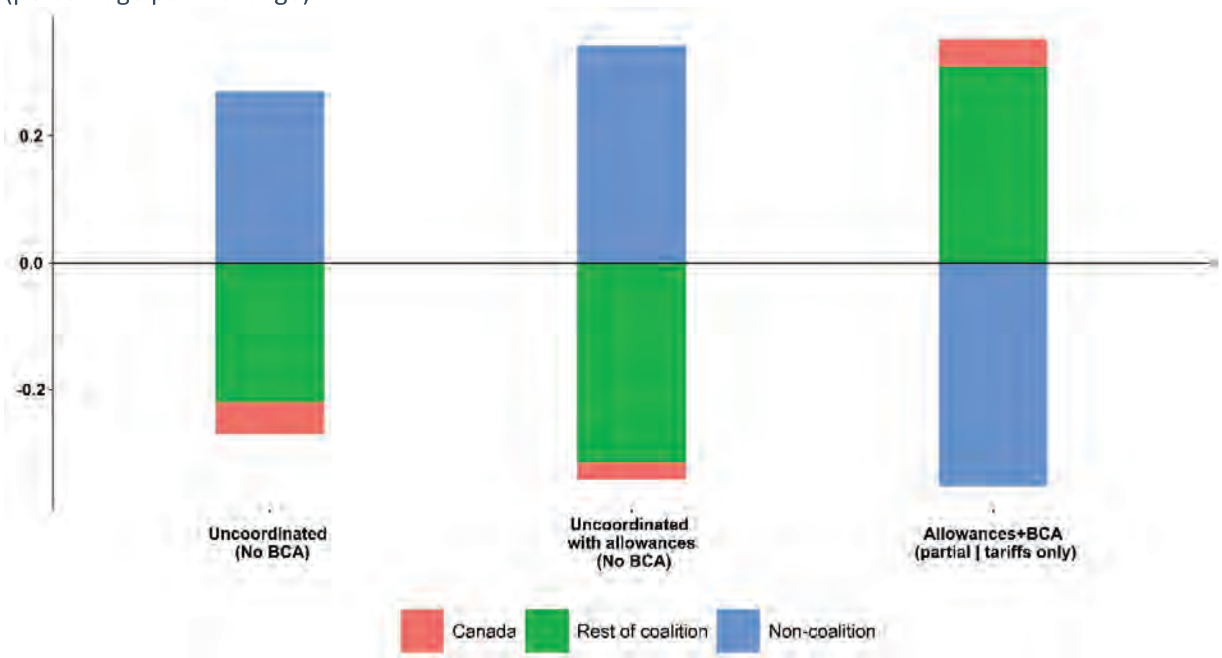
When BCAs are introduced on top of free allowances, we find that BCAs are effective in reducing carbon leakage from Canada to the rest of the world. Cumulative carbon leakage between 2020–30 might even become negative when BCAs are imposed, showing that non-coalition countries/regions might emit below their baseline under this scenario. Negative leakage is more likely when the elasticity of substitution between the good produced in the coalition countries/regions and the good produced in the non-coalition countries/regions is lower (as this reduces the terms-of-trade effect).[28] In terms of welfare changes, imposing BCAs on top of free allowances mitigates some of the welfare loss relative to the *uncoordinated scenario* (from -0.78 to -0.71 percentage change). Here, revenues from imposing BCAs, which are only in the form of import tariffs and returned to households, provide some compensation for losses due to higher prices (discussed below) resulting from the implementation of BCAs.

[27] This result is akin to the deadweight loss typically associated with production subsidies, namely the higher costs to government relative to the additional benefits accruing to consumers and producers.

[28] Negative leakage can also occur when the elasticity of substitution between clean inputs and fossil fuels is higher, as this increases the abatement resource effect. The abatement resource effect happens when increased demand for capital and labour to replace fossil fuels in carbon-taxed regions attracts factors of production from unregulated regions, which decreases unregulated output and ultimately emissions. For more explanation on negative leakage rates see Winchester and Rausch (2013). Given that in the EPPA model used in this study there is no capital and labour movement across countries, negative leakage ratios cannot be attributed to the abatement resource effect. Overall, negative leakage means non-coalition countries/regions might emit below their baseline after coalition countries/regions impose BCAs.

In terms of competitiveness, the results suggest that BCAs are effective in improving the domestic and foreign competitiveness of Canadian producers. Figure 1 shows the changes in average export market shares in the EITE sectors relative to the baseline under the three scenarios covered in Table 2. Under the *uncoordinated scenario*, coalition countries/regions (i.e., Canada, the EU, the US, Japan, Korea, and Mexico) lose market share due to their implementation of more stringent climate policies. While free allowances (introduced only in Canada and the EU) improve the average export market share for Canada, they are not as effective as BCAs in flipping this share in favour of the coalition. When BCAs are introduced on top of free allowances, Canada and the rest of the coalition gain export market shares and non-coalition countries/regions lose shares.

Figure 1 Average export market share changes in EITE sectors (2020–30) relative to the baseline scenario (percentage point change)



Another important implication of BCAs is the creation of a wedge between domestic prices and international prices. In the model, the sectoral price is the price that all producers in the economy pay for purchasing that sector's output and is an Armington composition of domestic and import prices. As shown in Figure 2, the introduction of free allowances generally put downward pressure on sectoral prices (orange bars). Adding BCAs, however, mitigates some of the downward pressure on sectoral prices (blue bars), but only for those sectors covered by the import tariff (cement, iron and steel, other energy-intensive sectors, and other manufacturing sectors). Since Canada is a net importer in these four sectors, we find an increase in the sectoral prices due to BCAs.

Figure 2 Average sectoral price changes (2020–30) relative to the uncoordinated scenario (%)

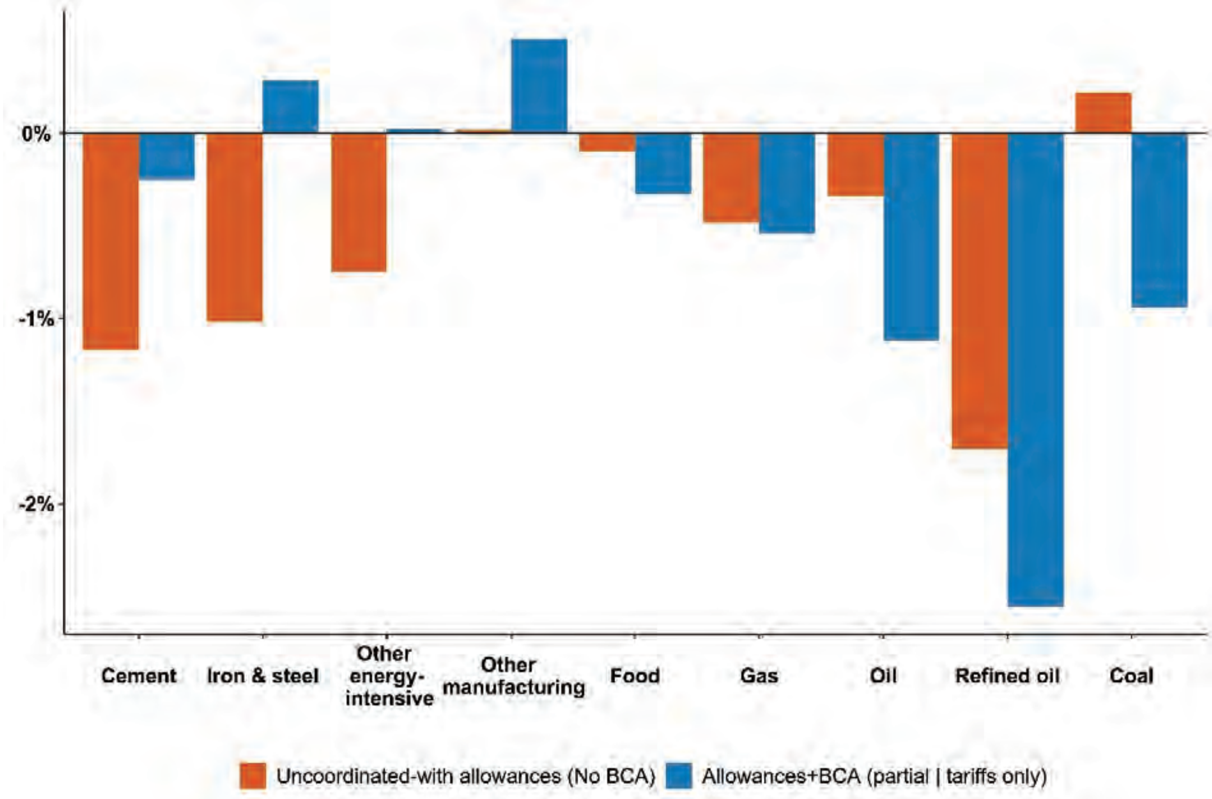
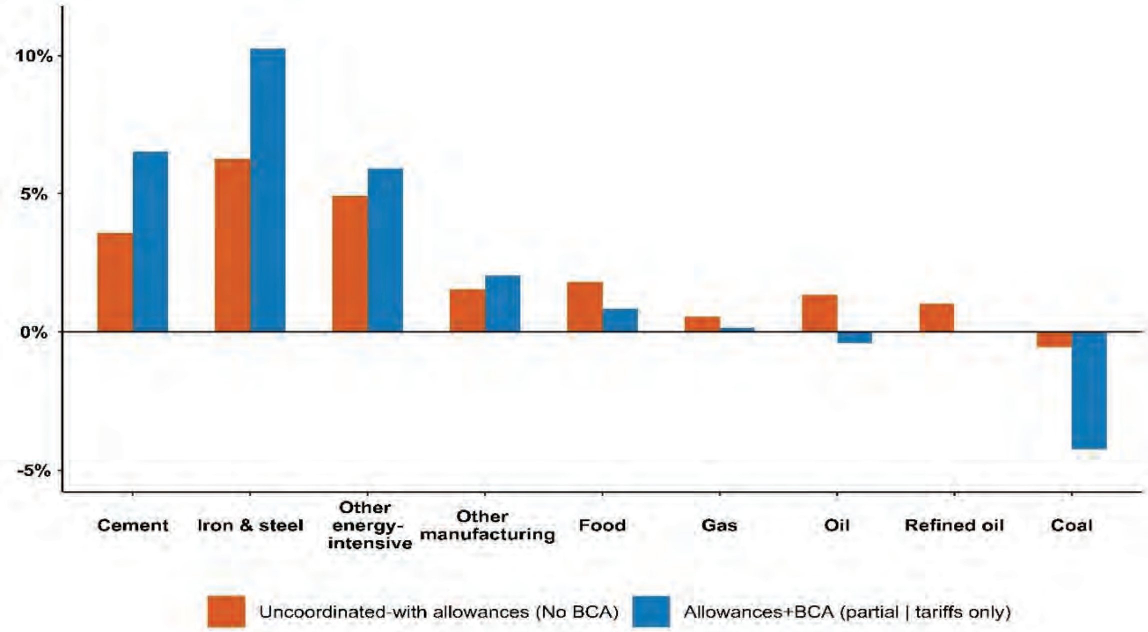


Figure 3 shows the positive financial impacts (defined as the difference between revenues and costs) for the cement, iron and steel, other energy-intensive sectors, and other manufacturing sectors. Producers benefit from higher prices for their output and higher domestic market shares because of the implementation of BCAs in the form of an import tariff.

Figure 3 Cumulative (2020–30) sectoral financial impacts relative to the uncoordinated scenario (%)



4.2. Does the design of BCAs matter?

To examine the design implications of BCAs, we consider the following features: 1) expanding the sectoral coverage to include fossil fuels and food sectors;[29] 2) adding export rebates (as defined in section 3.3) on top of import tariffs, with part of the revenues from the import tariffs now returned to EITE sectors; and 3) replacing free allowances with BCAs starting in 2020.[30] Table 3 summarizes the results associated with these additional design features. For ease of comparison, Table 3 also presents the previous relevant results, namely those related to the scenario considering the joint implementation of free allowances and BCAs, and when the later are in the form of import tariffs and applied to a partial set of sectors.[31]

First, expanding the sectoral coverage does not significantly change the effects of BCAs on carbon leakage (from -1.07 to -1.16 percentage point change). Part of the reason for this is because import tariffs are most relevant for sectors for which imports play a key role in the domestic economy—which in the Canadian context are those partial sectors (cement, iron and steel, other energy-intensive, and other manufacturing). In the case of fossil fuels, for example, Canada is a net exporter, and BCA import

[29] The food sector is an energy-intensive trade-exposed sector according to the Government of Canada (2021).

[30] As explained in section 3.3, the phasing out of free allowances is a scenario that is closer to what is proposed under initiatives like the CBAM. In fact, keeping free allowances while imposing import tariffs can be interpreted as double protection for domestic industries, raising challenges with WTO rules. It is for this reason that we consider the phasing out of the free allowances.

[31] We focused on scenarios shown in Table 3 to explain the effects of changing only one aspect of the policy design each time. Results from other scenarios studied are presented in Table 7 in Appendix D.

tariffs do little to affect carbon leakage from those sectors. However, expanding the sectoral coverage does increase the basket of imports exposed to tariffs, leading to an increase in the domestic market share relative to partial coverage (from 0.52 to 1.01 percentage point change). The foreign market share in turn remains unchanged at 0.4% change, as BCA import tariffs do not explicitly target exports. This case does not affect aggregate welfare.

Second, when export rebates are combined with import tariffs, carbon leakage is further reduced (-1.85 compared with –1.07) as less domestic production is lost in foreign markets to foreign competitors with weaker domestic climate policies. The results for this case show that the improvement in the domestic market share remains relatively unchanged (from 0.52 to 0.55 percentage point change), though the foreign market share increases (from 0.04 to 0.08 percentage point change). The addition of export rebates further levels out climate policy costs embedded in the price of goods between trading partners, alleviating losses in competitiveness in foreign markets. Yet the costs of this redistribution, as well as the general upward pressure on prices that export rebates induce (also discussed below in Figure 4), leads to a slight reduction of welfare (from -0.71 to -0.78 percentage point change).

Finally, as expected, replacing free allowances with BCAs is less effective in mitigating carbon leakage than when they are combined (0.75 compared with -1.07 percentage point change). This case also reduces domestic market share (0.01 compared with 0.52 percentage point change) and foreign market share (0.02 compared with 0.04 percentage point change) for relevant Canadian sectors. However, aggregate welfare loss is smaller when free allowances are replaced with BCAs (-0.59 compared with -0.71 percentage point change). This is because (as shown previously in Table 2), free allowances result in welfare loss while BCAs improve welfare.

Table 3 Cumulative (2020–30) impacts of different BCA design features relative to baseline

BCA design features	**Carbon leakage rate** (percentage)	**Domestic market share** (percentage point change)	**Foreign market share** (percentage point change)	**Welfare** (percentage changes in equivalent variation)
Allowances and import tariffs				
Allowances + BCA (partial | tariffs only)	-1.07	0.52	0.04	-0.71
1. Expanding the sectoral coverage				
Allowances + BCA (full | tariffs only)	-1.16	1.01	0.04	-0.71
2. Combining import tariffs and export rebates				
Allowances + BCA (partial | tariffs & rebates)	-1.85	0.55	0.08	-0.78
3. Replacing allowances with BCAs				
BCA (partial | tariffs only)	0.75	0.01	0.02	-0.59

Full = sectoral coverage refers to cement, coal, food, gas, iron and steel, oil, other energy-intensive sectors, other manufacturing, and refined oil
Partial = sectoral coverage excludes fossil fuels and only includes cement, iron and steel, other energy-intensive sectors, and other manufacturing

In terms of impacts on sectoral prices, Figure 4 shows that while expanding sectoral coverage does not have significant impacts on sectoral prices, combining import tariffs with export rebates slightly increases these prices. In addition, replacing free allowances with BCAs generally results in higher sectoral prices in comparison to the case when BCAs are combined with free allowances. This is due to the downward pressure of free allowances on sectoral prices. Also, under all design features considered, we generally observe price increases (or if they drop, the decrease is smaller than for other sectors) for those sectors in which imports have a higher share in domestic supply (cement, iron and steel, other energy-intensive sectors, other manufacturing sectors, and food).

Figure 4 Average sectoral price changes (over 2020–30) relative to the uncoordinated scenario (%)

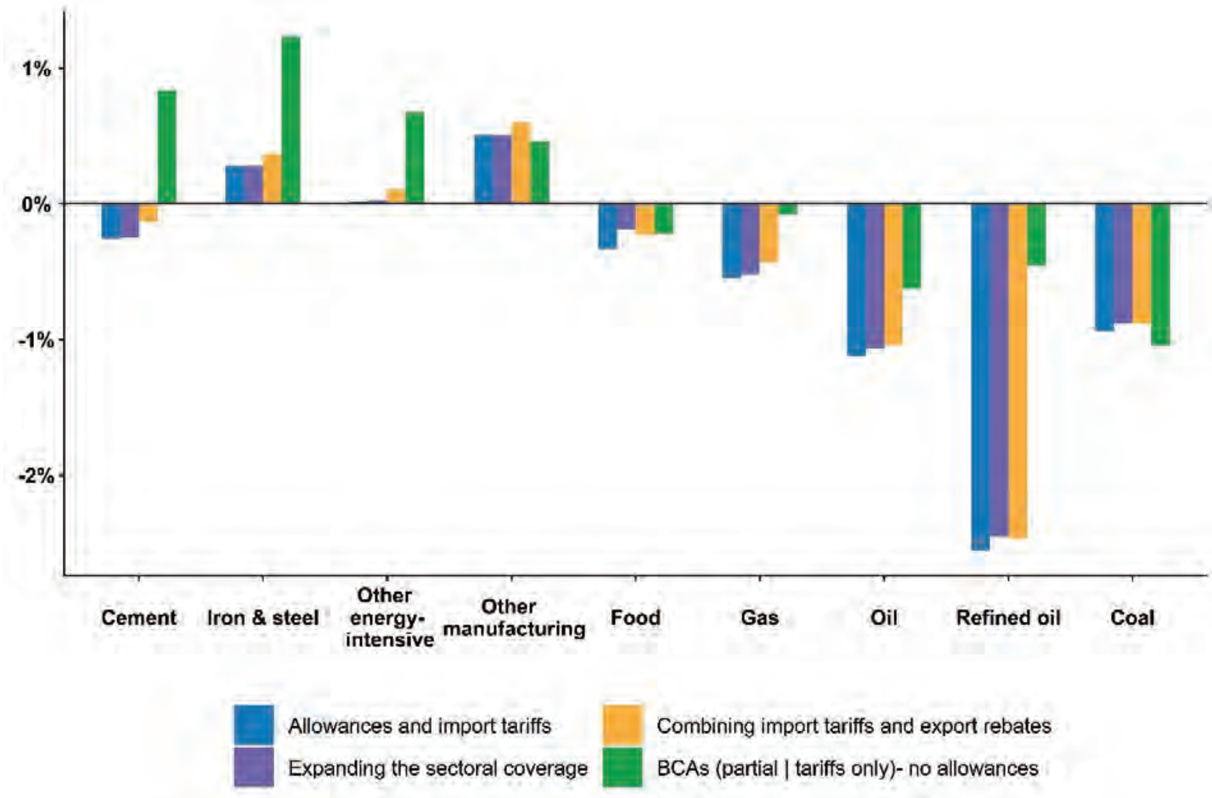
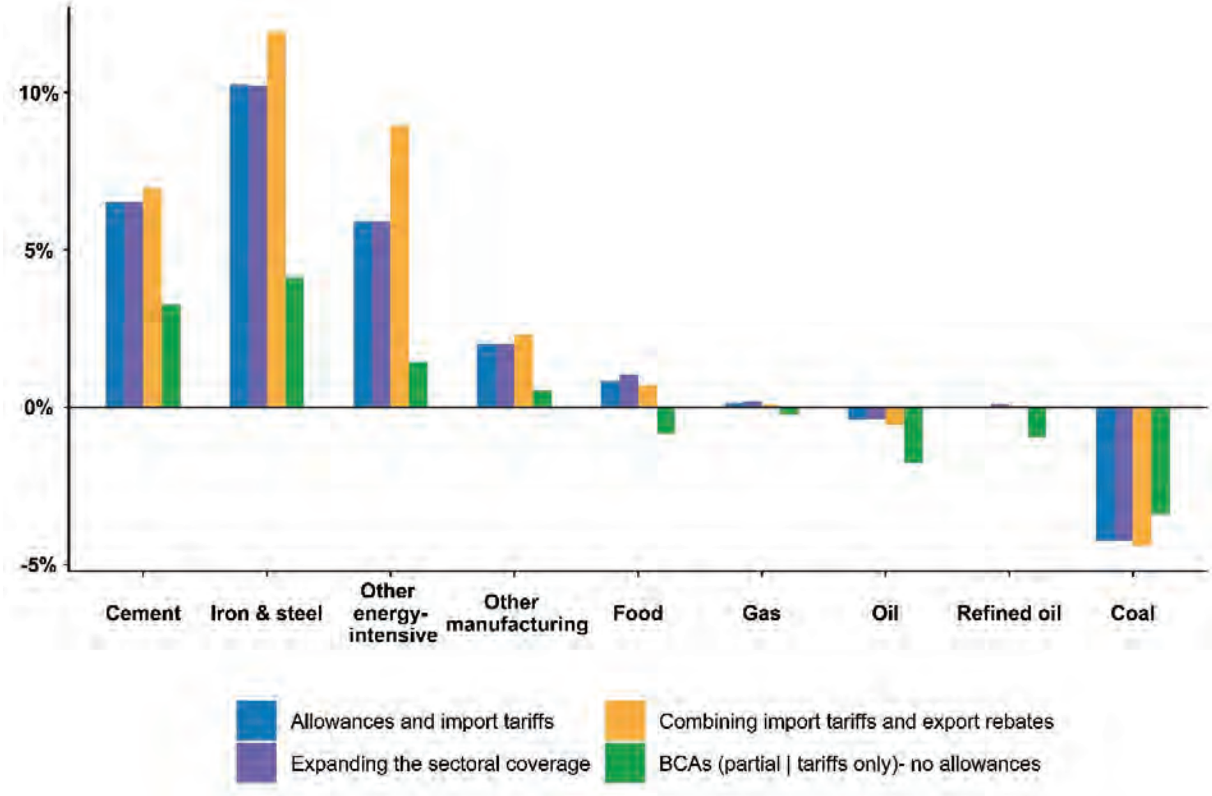


Figure 5 shows the sectoral financial impacts for the different BCA design features studied. First, while expanding sectoral coverage does not have significant financial impacts, combining import tariffs with export rebates provide benefits for some sectors, such as the energy-intensive sector. Second, combining BCAs with free allowances provides more benefits for some producers relative to replacing free allowances with BCAs. There are multiple channels through which BCAs affect producers. On the one hand, as shown above in Figure 4, sectors with higher rates of imports benefit from the upward pressure of import tariffs on sectoral prices in addition to increasing their domestic market shares. Producers also benefit from the addition of export rebates. On the other hand, producers face higher input costs due to the upward pressure BCAs have on prices, part of which are passed through to consumers. The net effect of these forces depends on the sector. Generally, we see that sectors for which imports have a higher share in domestic supply (cement, iron and steel, other energy-intensive sectors, other manufacturing sectors, and food) gain more domestic market share under BCAs. In Canada, those sectors are better off, while net-exporting sectors like fossil fuel sectors are slightly worse off.

Figure 5 Cumulative (2020–30) sectoral financial impacts relative to the uncoordinated scenario (%)



4.3. What happens when the US is out of the coalition?

Table 4 summarizes results when the US is not in the coalition relative to the case when the US was in the coalition for the same scenarios covered in Table 2 to capture the broader implications around the adoption of BCAs. In the absence of BCAs, Canada's carbon leakage to the rest of the world increases. In fact, the carbon leakage rate for Canada is higher for all the scenarios studied. In this case, domestic competitiveness deteriorates further since producers in the US now face less stringent climate policies, creating a comparative advantage for them.

When BCAs are introduced, Canada's domestic competitiveness is improved, since in this case Canada imposes tariffs on its main trading partner, the US, as well. However, BCAs result in larger upward pressure on prices in Canada (as shown in Figure 6), deteriorating Canada's foreign market share relative to the case when the US was in the coalition.

Furthermore, when the US is out of the coalition, the welfare loss due to the uncoordinated climate policy (no BCAs) is smaller for Canada to begin with (-0.34 relative to -0.67 percentage point change). This shows that more stringent climate policy in the US would have some negative impacts on Canadian welfare. Similar to the case when the US was in the coalition, adding free allowances when the US is out decreases welfare (from -0.34 to -0.45), while combining BCAs with free allowances increases welfare (from -0.45 to -0.28). However, when the US is out of the coalition, the revenues from imposing tariffs on imports coming from the US is larger, resulting in larger welfare gains when the schemes are combined (from -0.45 to -0.28 instead of going from -0.78 to -0.71 percentage change).

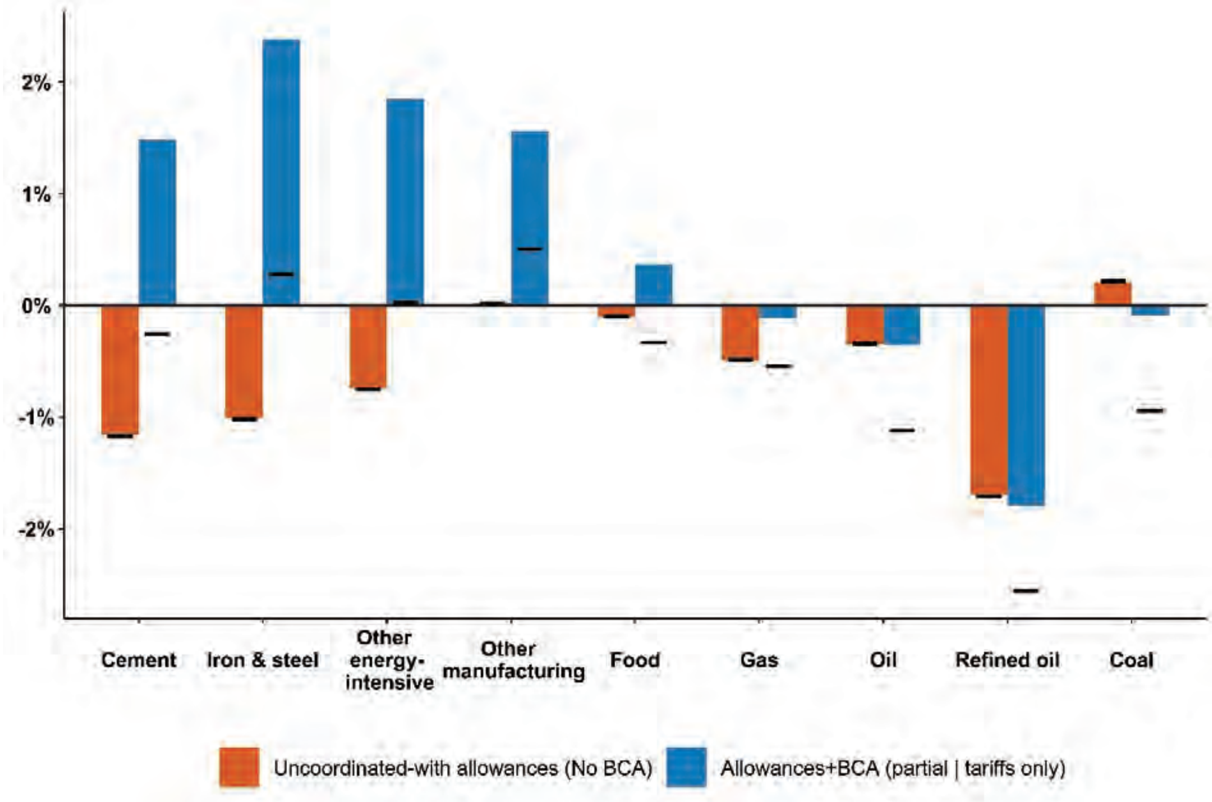
Table 4 Cumulative effects (2020–30) relative to baseline—US out of the coalition

Scenarios	**Carbon leakage rate** (percentage)	**Domestic market share** (percentage point change)	**Foreign market share** (percentage point change)	**Welfare** (percentage changes in equivalent variation)
2) Uncoordinated	9.10 (6.10)	-0.64 (-0.43)	-0.03 (-0.05)	-0.34 (-0.67)
2a) Uncoordinated with allowances	8.43 (4.38)	-0.09 (0.12)	-0.01 (-0.03)	-0.45 (-0.78)
3) Allowances + BCA (partial | tariffs only)	3.34 (-1.07)	0.66 (0.52)	-0.01 (0.04)	-0.28 (-0.71)

Note: The numbers in parenthesis show the results for the case when the US is in the coalition, previously shown in Table 3.

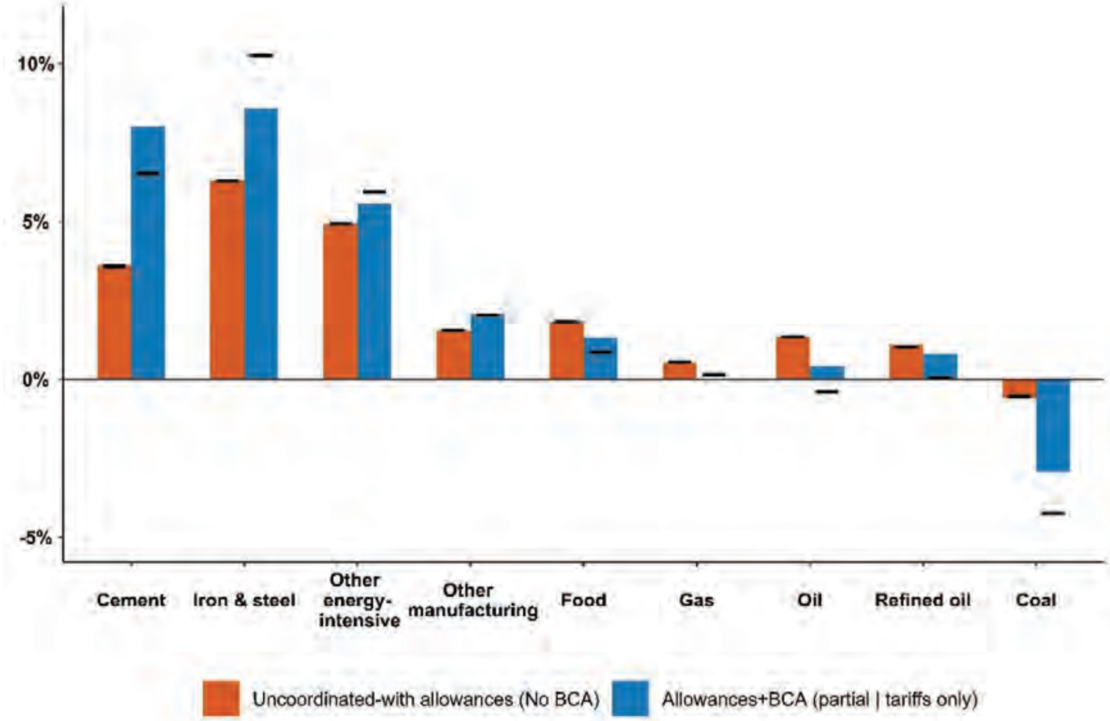
As shown in Figure 6, sectoral prices rise more when BCAs are imposed on US imports in addition to imports from other non-coalition regions to Canada. However, whether the US is in the coalition or not does not have significant financial impacts on Canadian producers (see Figure 7). On the one hand, when the US is not part of the coalition, Canadian producers benefit through increased domestic market share when tariffs are imposed on US imports relative to the case where they are not. On the other hand, as shown in Figure 6, sectoral prices rise more when BCAs are imposed on US imports. This in turn increases the input costs for Canadian producers, partly offsetting the gains in the domestic market share.

Figure 6 Average sectoral price changes (2020–30) relative to the uncoordinated scenario (%)—US out of the coalition



Note: The graph bars show the case when the US is out of the coalition, and the solid black lines represent the case when the US is in the coalition.

Figure 7 Cumulative (2020–30) sectoral financial impacts relative to the uncoordinated scenario (%)—US out of the coalition



Note: The graph bars show the case when the US is out of the coalition, and the solid black lines represent the case when the US is in the coalition.

5. Conclusion and discussion

Differences in the stringency of climate policy across countries have raised questions about their implications for carbon leakage and competitiveness, in particular for industries in countries subject to more stringent climate policies. Measures such as BCAs have been proposed to offset these implications.

This paper provided a quantification of Canadian economic impacts resulting from the implementation of BCAs. We examined implications related to which countries implement BCAs, different BCA design features, and the interaction of BCAs with existing measures also used to address carbon leakage and competitiveness matters. We have shown that the carbon leakage and economic impacts (domestic and foreign competitiveness as well as welfare) resulting from the implementation of BCAs for a country like Canada depend on the role played by the carbon content of a country's traded goods, the role these goods play in domestic production supply chains, and who the country trades with. Our analysis presents both the potential upside and downside of these different considerations, providing valuable insights into understanding the implications to the Canadian economy.

It is important to note that many challenges exist in implementing the various combinations of BCA and free allowance schemes represented in this paper, which presents an opportunity for further investigation in the future. For one, since Canadian provinces have led the development of carbon pricing schemes, imposing additional tariffs as a BCA measure at the federal level would be a significant challenge in reality (Boessenkool et al. 2022). As a result, one direction for future research is to account for potential differences in BCA measures at the provincial level, provided that regional input-output data for the Canadian economy are available. Another avenue is to explore an additional scenario where retaliations are triggered by trade partners suffering from Canada's BCAs imposed on their exports. To make this feasible, the regional resolution presented in this research may need to be significantly reduced for simplification and computational reasons.

ONTARIO GREENHOUSE VEGETABLE GROWERS

Ontario Greenhouse Vegetable Growers
32 Seneca Rd
Leamington, ON
N8H 5H7
www.greenhousegoodness.com

November 06, 2023

Ontario Energy Board (OEB)

RE: Enbridge Gas Inc. application for Leave to Construct the Panhandle Regional Expansion Project (EB-2022-0157)

Pursuant to the OEB's Procedural Order No. 8 dated October 30, 2023, the following is the written evidence of Dr. Robert Andrew Petro, the Energy, Infrastructure and Environment Co-Ordinator for the Ontario Greenhouse Vegetable Growers.

Thank you for the opportunity to provide commentary pertaining to Enbridge Gas Inc.'s application for leave to construct the Panhandle Regional Expansion Project. Ontario Greenhouse Vegetable Growers (OGVG) represents over 165 greenhouse vegetable producers accounting for more than 3,800 acres of fresh and affordable tomatoes, cucumbers, and peppers across Ontario, with over 80% of those producers located in the Leamington Kingsville area. Generating yearly farmgate sales exceeding $1 Billion since 2019, the greenhouse vegetable sector is a critical part of Ontario's exports and economy. The greenhouse vegetable sector has maintained an average year-over-year growth of 5% over the last 15 years and is projected to continue to grow at a rate of 5% per year throughout the decade, with over 2,000 acres planned the Leamington area provided that necessary incremental natural gas supply becomes available.

As noted above the Leamington-Kingsville region accounts for approximately 80% of Ontario's vegetable greenhouse acreage. The climate in the Leamington-Kingsville region is ideal for greenhouse agriculture which is why Leamington-Kingsville is projected to house nearly 2,000 acres of the projected additional 2,500 acres of new greenhouse development across Ontario over the coming decade. The development of the additional acreage will double greenhouse vegetable's contribution to GDP with farmgate sales alone projected to exceed $2 Billion/year by the end of the decade. As presented in this written testimony, the availability of natural gas is critical to Leamington-Kingsville for economic development, food sustainability and greenhouse expansion; without new natural gas capacity the material forecast growth in the greenhouse sector in the Leamington Kingsville area will not occur.

Growing Practices & Energy Requirements:

Modern greenhouse vegetable farms are state-of-the-art food production facilities leveraging and implementing innovative technologies including robotics, machine learning systems, and highly advanced lighting systems. The application of advanced lighting systems, specifically Light Emitting Diode (LED) and High-Pressure Sodium (HPS) lighting systems, has allowed Canadian greenhouses to extend their growing season into the winter months where heating is required to sustain the plants. Heating, used in the spring, summer, and fall to reduce humidity in the crop, is essential in the winter to maintain the greenhouse environment between 21°C and 27°C for optimal crop production. Capitalizing on the efficiency of scale, modern farms are built in 30-to-40-acre blocks with an electrical demand for lighting of approximately 0.5 MW/Acre.

Fundamentally commercial greenhouse farming requires light, water, carbon dioxide (CO_2), and heat as critical inputs to sustain photosynthesis and produce viable fruit in the crop. The output from the crop is proportional to the availability of both light and CO_2. To remain viable, efficient, and productive, greenhouse farms maintain an

ONTARIO GREENHOUSE VEGETABLE GROWERS

Ontario Greenhouse Vegetable Growers
32 Seneca Rd
Leamington, ON
N8H 5H7
www.greenhousegoodness.com

ambient CO_2 concentration of between 1,000-1,300 ppm which improves yield by 20% to 30%[1] and requires up to 250 tonnes of CO_2 per acre per year. Without CO_2 supplementation, the ambient concentration of CO_2 would drop to below 200 ppm within an hour causing irreversible damage to the crop. According to the international Energy Agency (IEA), CO_2 use to enhance the yields of biological processes is one of the preferred uses for CO_2 from CO_2 generating activities. By way of example, in the Netherlands annual consumption of CO_2 is between 5 and 6.3 MtCO2[2] (4.5 and 5.7 million tonnes) across approximately 5,000 hectares (12,000 acres) or at least 375 tonnes per acre per year. Due to increased energy prices and a shortage of natural gas, greenhouse vegetable production in the Netherlands fell by 7.9% in 2022,[3] demonstrating the need for reliable energy and CO_2 supplies and the sensitivity of greenhouse operations to fluctuations in the availability of both.

Greenhouse farms have adapted natural gas usage to fulfill both their heating needs and supplement their demand for CO_2. Sourcing CO_2 from natural gas has been fundamental to unlocking efficient winter farming and reducing the demand for imported liquid CO_2. During the spring, summer, and fall natural gas is burned during the day to supply the crop with CO_2 and the heat is stored in tanks to provide the heat when it is needed. The technological advances in the greenhouse sector including the smart climate systems have further supported greenhouse farms in using natural gas efficiently and maximizing the benefits of natural gas.

Natural gas has further supported greenhouse farming with the adaptation of combined heat and power (cogeneration) providing electricity for lights, heat for greenhouse, and CO_2 to the crop. Farms in Leamington-Kingsville adopted cogeneration due in part to a lack of capacity in the local electrical grid. As a result, throughout Ontario, nearly 90 Megawatts (MW) of electricity are produced by greenhouse operations and supplied to Ontario's energy grid with the CO_2 generated by these engines sequestered by greenhouse operations.

Critically, of the 1400 MW transmission capacity planned for Windsor-Essex by 2031, greenhouse operations are expected to require 600 MW to 750 MW of that incoming capacity without accounting for electrification of production through automation or electrical assets and vehicles. Cogeneration is yet another way natural gas is utilized efficiently within greenhouse operations to support economic growth.

Alternatives:

Investment in the greenhouse sector amounts to millions of dollars per farm per year with the value of a crop climbing to the tens of millions for some greenhouse ranges. Due to the value invested into their crop, growers often use secondary or backup systems to protect their investment. Some have chosen to augment their natural gas with backup systems including diesel, fuel oil, or biomass.

Many growers have investigated geothermal loops and heat pumps as an avenue to heat their greenhouse farms. Despite enhancements in geothermal technology, no system has been able to overcome the geological limitations in the Leamington-Kingsville area which include a high-water table and poor soil conditions requiring lateral systems and significant land. The lack of electrical capacity in the Leamington area, estimated today to be less than 40 MW available, further limits large farms from adopting electricity-based heat pumps and restricts the choice between heating or lighting the crop. However, both electrification in general and heat pumps in particular remain at best a secondary source of heat due to the lack of CO_2 produced from either source. The sourcing and

1 https://www.iea.org/reports/putting-co2-to-use
2 https://www.iea.org/reports/putting-co2-to-use
3 https://www.hortidaily.com/article/9520941/energy-crisis-results-fewer-dutch-greenhouse-tomatoes-and-cucumbers-in-2022/

main: 519-326-2604
toll free: 1-800-265-6926
fax: 519-326-7842

ONTARIO GREENHOUSE VEGETABLE GROWERS

Ontario Greenhouse Vegetable Growers
32 Seneca Rd
Leamington, ON
N8H 5H7
www.greenhousegoodness.com

supply of CO_2 without onsite generation presents the most significant challenge and risks directly exposing farms to the volatility of liquid CO_2 market which has seen increases of almost 3,000% [4] in some areas of the global market. As CO_2 is a critical input, subjecting farms to the volatility of the CO_2 market presents a competitive disadvantage against existing farms that generate CO_2 onsite from natural gas.

The example of H&A Mastronardi demonstrates the need for CO_2 and commitment to sustainability rather than venting the CO_2 produced by the biomass. According to Ontario's "Greenhouse Gas Emissions Reporting By Facility" [5] 20% of H&A Mastronardi's emissions in 2019 and 2020 originated from biomass while the other 80% originated from natural gas. The choice of growers to utilize biomass as a secondary heating source is due entirely to the low cost of obtaining waste wood that would otherwise be sent to a landfill. The wider use of biomass as a full replacement for natural gas is, however, limited by cost, logistics, and the space required for biomass storage. In the example cited from Dias et al.[6] 50,000 hectares (500 km^2) of land would be needed to produce the biomass needed for just the annual (2016) production of tomatoes in Leamington. Tomatoes are only one-third of the production in Leamington-Kingsville, with peppers and cucumbers each taking up similar acreage. Without accounting for the new crop types being introduced into the region, including strawberries and lettuce amongst others, 150,000 hectares of biomass production would be needed just to fuel existing tomato, cucumber, and pepper operations. By 2031 the required acreage would be projected to be more than twice the 2016 value, meaning that, were biomass adopted as an alternative fuel source, 3,000 km^2 of land, or more than the entire municipality of Chatham-Kent (2,457.90 km^2), would be needed to supply the annual need for biomass to the greenhouse sector in Leamington. The cost of land including the displaced field farming activities, the processing cost, the environmental and monetary transportation cost of the biomass in addition to the more expensive cost of post processing to provide CO_2 to the crop makes biomass unfeasible.

Natural gas has presented the best solution for heating with the added benefit of producing critically needed carbon dioxide for the crop. The heating provided from natural gas amounts to an average of over 5,000 MMBTU per acre per year, or over 1,500 MWh equivalent of energy per acre. The forecast increase in local sustainable production of greenhouse vegetables and the increased local generation of electricity through sustainable cogeneration will become impossible without new natural gas capacity in the region.

Sustainability:

Greenhouse farms have an intense commitment to efficiency and sustainability as both are directly reflected in their ability to operate profitably. Projects OGVG members have supported include carbon capture and release technologies to eliminate all asynchronicities in their deployment of generated CO_2, continuous lighting to provide constant light and CO_2 to allow for more regulated CO_2 uptake, use of greenhouse waste in renewable natural gas processes such as digesters and landfill recapture, and hydrogen blending to reduce CO_2 density of natural gas and facilitate capture and redeployment.

The investigation of renewable hydrogen through the Hydrogen Integrated Greenhouse Horticultural (HIGH) Energy project[7] is a partnership between OGVG, the University of Windsor, and Kruger Energy to reduce natural

[4] https://www.morningadvertiser.co.uk/Article/2022/10/03/Soaring-gas-prices-could-result-in-liquid-CO2-and-beer-shortages
[5] https://data.ontario.ca/dataset/greenhouse-gas-emissions-reporting-by-facility/resource/0996bfd9-ed27-4f78-8ed1-9e024185f10a
[6] Dias, G. M. et al. (2017). Life cycle perspectives on the sustainability of Ontario greenhouse tomato production: Benchmarking and improvement opportunities. Journal of Cleaner Production. 140(2): 831-9. https://doi.org/10.1016/j.jclepro.2016.06.039
[7] https://www.ogvg.com/post/new-joint-venture-to-examine-potential-for-wind-farm-production-to-power-greenhouse-sector

ONTARIO GREENHOUSE VEGETABLE GROWERS

Ontario Greenhouse Vegetable Growers
32 Seneca Rd
Leamington, ON
N8H 5H7
www.greenhousegoodness.com

gas emissions through hydrogen blending and increase renewable energy deployment, through hydrogen blending, in the greenhouse sector. Hydrogen blending of up to 20% will reduce the CO_2 produced by natural gas use without requiring greenhouses to become reliant on CO_2 supply chains which can be prone to shortages and price shocks[8]. A shortage of CO_2 would be devastating to the greenhouse sector, as without a means of generating CO_2 the greenhouse sector would fail.

Conclusion:

Natural gas remains the best, most economically and scientifically viable source of heat and CO_2 for the greenhouse sector in the region serviced by Panhandle transmission system. Without additional natural gas supply greenhouse farm development in the area served by the Panhandle transmission system will cease, sustainable goals in hydrogen blending for the greenhouse sector will not be realized and investment in the greenhouse sector along with the associated benefits will flow to jurisdictions outside of Ontario such as Michigan, Ohio, and North Carolina.

[8] https://www.chemanalyst.com/Pricing-data/liquid-carbon-dioxide-1090

PROPOSED REGULATORY TEXT

Notice is given, under subsection 332(1)[a] of the *Canadian Environmental Protection Act, 1999*[b], that the Governor in Council proposes to make the annexed *Clean Electricity Regulations* under subsections 93(1), section 286.1[c] and subsection 330(3.2)[d] of that Act.

Any person may, within 75 days after the date of publication of this notice, file with the Minister of the Environment comments with respect to the proposed Regulations or a notice of objection requesting that a board of review be established under section 333 of that Act and stating the reasons for the objection. Persons filing comments are strongly encouraged to use the online commenting feature that is available on the *Canada Gazette* website. Persons filing comments by any other means, and persons filing a notice of objection, should cite the *Canada Gazette*, Part I, and the date of publication of this notice, and send the comments or notice of objection to Karishma Boroowa, Director, Electricity and Combustion Division, Environment and Climate Change Canada, 351 Saint-Joseph Boulevard, Gatineau, Quebec, K1A 0H3 (email: ECD-DEC@ec.gc.ca).

Any person who provides information to the Minister may submit with the information a request for confidentiality under section 313 of that Act.

Ottawa, August 9, 2023

Wendy Nixon
Assistant Clerk of the Privy Council

PROJET DE RÉGLEMENTATION

Avis est donné, conformément au paragraphe 332(1)[a] de la *Loi canadienne sur la protection de l'environnement (1999)*[b], que la gouverneure en conseil, en vertu du paragraphe 93(1), de l'article 286.1[c] et du paragraphe 330(3.2)[d] de la même loi, se propose de prendre le *Règlement sur l'électricité propre*, ci-après.

Les intéressés peuvent présenter au ministre de l'Environnement, dans les soixante-quinze jours suivant la date de publication du présent avis, leurs observations au sujet du projet de règlement ou un avis d'opposition motivé demandant la constitution de la commission de révision prévue à l'article 333 de la même loi. Ceux qui présentent des observations sont fortement encouragés à le faire au moyen de l'outil en ligne disponible à cet effet sur le site Web de la *Gazette du Canada*. Ceux qui présentent leurs observations par tout autre moyen, ainsi que ceux qui présentent un avis d'opposition, sont priés d'y citer la Partie I de la *Gazette du Canada*, ainsi que la date de publication du présent avis, et d'envoyer le tout à Karishma Boroowa, directrice, Division de l'électricité et de la combustion, Direction de l'énergie et des transports, Direction générale de la protection de l'environnement, ministère de l'Environnement, 351, boul. Saint-Joseph, Gatineau (Québec) K1A 0H3 (courriel : ECD-DEC@ec.gc.ca).

Quiconque fournit des renseignements au ministre peut en même temps présenter une demande de traitement confidentiel aux termes de l'article 313 de cette loi.

Ottawa, le 9 août 2023

La greffière adjointe du Conseil privé
Wendy Nixon

Clean Electricity Regulations

Purpose

Purpose

1 These Regulations establish a regime for limiting carbon dioxide (CO_2) emissions that result from the generation of electricity from the combustion of fossil fuels.

Règlement sur l'électricité propre

Objet

Objet

1 Le présent règlement établit un régime visant la réduction des émissions de dioxyde de carbone (CO_2) provenant de la production d'électricité à partir de la combustion de combustibles fossiles.

---

[a] S.C. 2004, c. 15, s. 31
[b] S.C. 1999, c. 33
[c] S.C. 2009, c. 14, s. 80
[d] S.C. 2008, c. 31, s. 5

[a] L.C. 2004, ch. 15, art. 31
[b] L.C. 1999, ch. 33
[c] L.C. 2009, ch. 14, art. 80
[d] L.C. 2008, ch. 31, art. 5

Interpretation

Interpretation

2 (1) The following definitions apply in these Regulations.

API means the American Petroleum Institute. (*API*)

ASTM means ASTM International, formerly known as the American Society for Testing and Materials. (*ASTM*)

auditor means an individual who

(a) is independent of the responsible person that is to be audited; and

(b) has knowledge of and has experience with respect to

(i) the certification, operation and relative accuracy test audit of continuous emission monitoring systems, and

(ii) quality assurance and quality control procedures in relation to those systems. (*vérificateur*)

authorized official means

(a) in respect of a responsible person that is a corporation, an officer of the corporation that is authorized to act on its behalf;

(b) in respect of a responsible person that is an individual, that individual or an individual who is authorized to act on that individual's behalf; and

(c) in respect of a responsible person that is another entity, an individual authorized to act on that other entity's behalf. (*agent autorisé*)

biomass means plants or plant materials, animal waste or any product made of either of these, including wood and wood products, bio-charcoal, agricultural residues, biologically derived organic matter in municipal and industrial wastes, landfill gas, bio-alcohols, pulping liquor, sludge digestion gas and fuel from animal or plant origin. (*biomasse*)

coal includes petroleum coke and synthetic gas that is derived from coal or petroleum coke. (*charbon*)

coal gasification system includes a coal gasification system that is in part located underground. (*système de gazéification du charbon*)

combustion engine means an engine, other than an engine that is self-propelled or designed to be propelled while performing its function, that

(a) operates according to the Brayton thermodynamic cycle and combusts fossil fuel to produce a net amount of motive power; or

Définitions et interprétation

Définitions

2 (1) Les définitions qui suivent s'appliquent au présent règlement.

agent autorisé

a) Dans le cas où la personne responsable est une personne morale, celui de ses dirigeants qui est autorisé à agir en son nom;

b) dans le cas où elle est une personne physique, celle-ci ou la personne physique qui est autorisée à agir en son nom;

c) dans le cas où elle est une autre entité, la personne physique qui est autorisée à agir en son nom. (*authorized official*)

API L'American Petroleum Institute. (*API*)

ASTM L'ASTM International, auparavant connue sous le nom de American Society for Testing and Materials. (*ASTM*)

biomasse Vise les plantes ou matières végétales, déchets d'origine animale ou leurs produits dérivés, notamment le bois et les produits du bois, le charbon de bois, les résidus d'origine agricole, la matière organique d'origine biologique dans les déchets urbains et industriels, les gaz d'enfouissement, les bioalcools, la liqueur de cuisson, les gaz de digestion des boues ainsi que les combustibles d'origine animale ou végétale. (*biomass*)

capacité de production d'électricité À l'égard d'un groupe et d'une année civile :

a) soit la puissance maximale — la puissance nette maximale qui peut être maintenue en continu par le groupe, dans des conditions normales — la plus récente qui a été déclarée à l'autorité provinciale responsable ou à l'exploitant de réseau électrique dans la province où le groupe se trouve, exprimée en MW;

b) soit, en l'absence d'une telle déclaration, la quantité maximale d'électricité destinée à la vente qui est produite de façon continue par ce groupe pendant deux heures au cours de l'année en cause, exprimée en MW. (*electricity generation capacity*)

charbon Sont assimilés au charbon le coke de pétrole et le gaz de synthèse provenant du charbon ou du coke de pétrole. (*coal*)

combustible fossile Combustible autre que la biomasse. Y est assimilé l'hydrogène. (*fossil fuel*)

conditions normales Conditions qui correspondent à une température de 15 °C et à une pression de 101,325 kPa. (*standard conditions*)

(b) combusts fossil fuel and uses reciprocating motion to convert thermal energy into mechanical work. (*moteur à combustion*)

commissioning date means the day on which the oldest boiler or combustion engine in the unit starts operating. (*date de mise en service*)

continuous emission monitoring system or ***CEMS*** means equipment for the sampling, conditioning and analyzing of emissions from a given source and the recording of data related to those emissions. (*système de mesure et d'enregistrement en continu des émissions* ou *SMECE*)

electricity generation capacity, in relation to a unit and a calendar year, means

(a) the maximum continuous rating — the maximum net power than can be continuously sustained by the unit at standard conditions — of the unit, expressed in MW, as most recently reported to a provincial authority of competent jurisdiction or to the electric system operator in the province where the unit is located; or

(b) if no report has been made, the most electricity that was produced for sale by the unit, expressed in MW, during two continuous hours in that calendar year. (*capacité de production d'éléctricité*)

facility means units, buildings, other structures, stationary equipment — including equipment used for hydrogen fuel production and equipment used for fuel production from coal gasification — on a single site or on contiguous sites or adjacent sites that function as a single integrated site at which an industrial activity is carried out. (*installation*)

fossil fuel means a fuel other than biomass. It includes hydrogen gas. (*combustible fossile*)

GHGRP means the document entitled *Canada's Greenhouse Gas Quantification Requirements, Greenhouse Gas Reporting Program*, published by the Department of the Environment in 2021. (*méthode d'ECCC*)

NERC means the North American Electric Reliability Corporation. (*NERC*)

net exports means for a given calendar year, the amount of electricity exported from a unit to an electricity system that is subject to NERC standards minus the amount of electricity imported to a unit from an electricity system that is subject to NERC standards, in GWh, measured using electricity meters that comply with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*. (*solde exportateur*)

date de mise en service Date à laquelle la plus vieille chaudière ou le plus vieux moteur à combustion du groupe commence à fonctionner. (*commissioning date*)

énergie thermique utile Énergie, sous forme de vapeur ou d'eau chaude, destinée à être utilisée à une fin, autre que la production d'électricité, qui, n'était l'utilisation de cette vapeur ou de cette eau chaude, nécessiterait la consommation d'énergie sous forme de combustible ou d'électricité. (*useful thermal energy*)

exploitant Personne ayant toute autorité sur un groupe. (*operator*)

groupe Ensemble qui est constitué de tout équipement physiquement raccordé et fonctionnant ensemble pour produire de l'électricité et qui répond aux conditions suivantes :

a) il comporte au moins une chaudière ou un moteur à combustion;

b) il peut comporter des brûleurs d'appoint et d'autres dispositifs de combustion, des systèmes de récupération de chaleur, des turbines à vapeur, des générateurs, des dispositifs de contrôle des émissions et des systèmes de captage et de stockage de carbone. (*unit*)

installation Ensemble des groupes, bâtiments, autres structures et équipements fixes — y compris les équipements utilisés pour la production d'hydrogène et ceux utilisés pour la production de carburant à partir de la gazéification du charbon — sur un site unique, ou sur des sites contigus ou adjacents qui fonctionnent comme un site intégré unique, sur lequel une activité industrielle est exercée. (*facility*)

méthode de référence Le document publié par le ministère de l'Environnement intitulé *Méthode de référence pour le contrôle à la source : quantification des émissions de dioxyde de carbone des centrales thermiques par un système de mesure et d'enregistrement en continu des émissions*, daté de juin 2012. (*Reference Method*)

méthode d'ECCC Le document intitulé *Exigences relatives à la quantification des gaz à effet de serre au Canada, Programme de déclaration des gaz à effet de serre*, publié en 2021 par le ministère de l'Environnement. (*GHGRP*)

moteur à combustion Tout moteur, à l'exception du moteur autopropulsé et du moteur conçu pour être propulsé tout en accomplissant sa fonction et qui, selon le cas :

a) fonctionne selon le cycle thermodynamique de Brayton et brûle du combustible fossile en vue de la production d'une quantité nette de force motrice;

operator means a person who has the charge, management or control of a unit. (*exploitant*)

Reference Method means the document entitled *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation*, June 2012, published by the Department of the Environment. (*méthode de référence*)

responsible person means an owner or operator of a unit. (*personne responsable*)

standard conditions means a temperature of 15 °C and a pressure of 101.325 kPa. (*conditions normales*)

unit means an assembly comprised of any equipment that is physically connected and that operates together to generate electricity, and

(a) must include at least a boiler or combustion engine, and

(b) may include duct burners and other combustion devices, heat recovery systems, steam turbines, generators, emission control devices and carbon capture and storage systems. (*groupe*)

useful thermal energy means energy in the form of steam or hot water that is destined for a use, other than the generation of electricity, that would have required the consumption of energy in the form of fuel or electricity had that steam or hot water not been used. (*énergie thermique utile*)

b) brûle du combustible fossile et qui utilise un mouvement alternatif en vue de la conversion d'énergie thermique en travail mécanique. (*combustion engine*)

NERC La North American Electric Reliability Corporation. (*NERC*)

personne responsable Le propriétaire ou l'exploitant d'un groupe. (*responsible person*)

solde exportateur Pour une année civile donnée, quantité d'électricité exportée par un groupe vers un réseau électrique assujetti aux normes de la NERC, exprimée en GWh, moins la quantité d'électricité importée par un groupe d'un réseau électrique assujetti aux normes de la NERC, exprimée en GWh, quantifiée à l'aide de compteurs d'électricité qui sont conformes aux exigences de la *Loi sur l'inspection de l'électricité et du gaz* et du *Règlement sur l'inspection de l'électricité et du gaz*. (*net exports*)

système de gazéification du charbon S'entend notamment d'un système de gazéification du charbon qui est en partie souterrain. (*coal gasification system*)

système de mesure et d'enregistrement en continu des émissions ou ***SMECE*** Équipement destiné à l'échantillonnage, au conditionnement et à l'analyse d'émissions provenant d'une source donnée, ainsi qu'à l'enregistrement de données concernant ces émissions. (*continuous emission monitoring system* or *CEMS*)

vérificateur Personne physique qui, à la fois :

a) est indépendante de la personne responsable faisant l'objet de la vérification;

b) possède des connaissances et de l'expérience en ce qui touche :

(i) la certification, l'exploitation et la vérification de l'exactitude relative des systèmes de mesure et d'enregistrement en continu des émissions,

(ii) les procédures d'assurance de la qualité et de contrôle de la qualité relatives à ces systèmes. (*auditor*)

More than one owner or operator

(2) For the purposes of the definition of *facility*, if there is more than one owner or operator for the facility, those elements are only included in the definition of facility if there is at least one owner or operator in common.

Plus d'un propriétaire ou exploitant

(2) Pour l'application de la définition de *installation*, s'il y a plus d'un propriétaire ou exploitant en commun, les éléments visés à cette définition ne sont compris dans celle-ci que s'ils ont en commun un même propriétaire ou exploitant.

Carbon capture and storage

(3) Equipment that is connected only by a carbon capture and storage system is not considered physically connected for the purposes of the definition of *unit* in subsection (1). That carbon capture and storage system must be included in the description of each unit connected to it.

Captage et de stockage de carbone

(3) Les équipements qui sont raccordés uniquement par un système de captage et de stockage de carbone ne sont pas considérés comme étant raccordés physiquement pour l'application de la définition de *groupe*, au paragraphe (1). Le système de captage et de stockage de carbone est inclus dans la description de chacun des groupes auquel il est raccordé.

Interpretation of documents incorporated by reference

(4) For the purposes of interpreting documents that are incorporated by reference into these Regulations, "should" is to be read as "must" and any recommendation or suggestion is to be read as an obligation.

Incorporation by reference

(5) Unless otherwise indicated, a reference to any document incorporated by reference into these Regulations, except the GHGRP, is incorporated as amended from time to time.

Application

Specified units

3 These Regulations apply to a unit that, on or after January 1, 2025, meets the following criteria:

(a) has an electricity generation capacity of 25 MW or more;

(b) generates electricity using fossil fuel; and

(c) is connected to an electricity system that is subject to NERC standards.

Registration

Registration Report

4 (1) A responsible person must register the unit by submitting a registration report to the Minister that contains the information set out in Schedule 1

(a) in the case of a unit that has a commissioning date on or after January 1, 2025, within 60 days after the date on which the unit was commissioned; or

(b) in the case of all other units, by December 31, 2025.

Modification

(2) If a unit is modified, such as by adding or removing a piece of equipment or changing how equipment is physically connected, and that modification creates one or more new units, the responsible person must

(a) register any new unit by submitting a registration report to the Minister that contains the information set out in Schedule 1 within 30 days after the date on which the unit was created; and

Interprétation des documents incorporés par renvoi

(4) Pour l'interprétation des documents incorporés par renvoi dans le présent règlement, toute mention de « should » ainsi que les recommandations et suggestions expriment une obligation.

Incorporation par renvoi

(5) Sauf indication contraire, toute mention d'un document incorporé par renvoi dans le présent règlement constitue un renvoi au document avec ses modifications successives, à l'exception de la méthode d'ECCC.

Champ d'application

Groupes visés

3 Le présent règlement s'applique à tout groupe qui, le 1er janvier 2025 ou après cette date, remplit les conditions suivantes :

a) il a une capacité de production d'électricité d'au moins vingt-cinq MW;

b) il produit de l'électricité à partir de combustibles fossiles;

c) il est connecté à un réseau électrique assujetti aux normes de la NERC.

Enregistrement

Rapport d'enregistrement

4 (1) La personne responsable d'un groupe transmet au ministre pour fins d'enregistrement un rapport d'enregistrement comportant les renseignements visés à l'annexe 1 dans l'un des délais suivants :

a) dans le cas d'un groupe dont la date de mise en service est le 1er janvier 2025 ou postérieure à cette date, le soixantième jour après la date de mise en service;

b) dans les autres cas, le 31 décembre 2025.

Modification

(2) Si un groupe subit une modification, notamment par l'ajout ou le retrait d'une pièce d'équipement ou par une modification dans la façon dont les équipements sont raccordés ensemble, qui a pour effet de créer un ou plusieurs nouveaux groupes, la personne responsable, selon le cas :

a) enregistre tout nouveau groupe en transmettant au ministre un rapport d'enregistrement comportant les renseignements visés à l'annexe 1 au plus tard trente jours après la création du groupe;

(b) notify the Minister that either the original unit has ceased to generate electricity, in accordance with subsection 24(3), or has been modified, in accordance with section 25.

Registration number

(3) On receipt of the registration report, the Minister must assign a registration number to the unit and inform the responsible person of that registration number.

Net Exports Declaration

Declaration

5 (1) A responsible person may submit to the Minister a declaration, dated and signed by the responsible person or their authorized official, stating that net exports with respect to their unit are less than or equal to 0 GWh and containing the following information:

(a) the unit's registration number, assigned by the Minister under subsection 4(3); and

(b) an attestation that the declaration is accurate and complete.

December 31

(2) The declaration must be submitted to the Minister on or before December 31 of the calendar year prior to the calendar year in which the prohibition set out in subsection 6(1) will apply to that unit.

Exemptions

(3) If a declaration has been submitted with respect to a unit, the responsible person is exempt from sections 6 to 24.

Short report

(4) A responsible person for a unit with respect to which a declaration has been submitted must submit a short report to the Minister, containing the information set out in sections 1 and 2 of Schedule 2 and the net exports for that unit for the calendar year, on or before the June 1 that follows the calendar year that is the subject of the report.

Exemption ends

(5) Subject to subsection (6), the exemptions in subsection (3) do not apply with respect to the unit if the unit has net exports that are greater than 0 GWh in any calendar year.

Emergency exemption

(6) If a unit has net exports that are greater than 0 GWh in a calendar year due to the quantity of electricity being exported from the unit during a period for which the

b) transmet au ministre un avis de cessation définitive de production d'électricité conformément au paragraphe 24 (3) ou un avis de modification des renseignements conformément à l'article 25, selon le cas.

Numéro d'enregistrement

(3) Sur réception d'un rapport d'enregistrement, le ministre assigne un numéro d'enregistrement au groupe et informe la personne responsable de ce numéro.

Déclaration relative au solde exportateur

Déclaration

5 (1) La personne responsable peut transmettre au ministre une déclaration, datée et signée par elle ou son agent autorisé, portant que le solde exportateur du groupe sera égal ou inférieur à zéro GWh. La déclaration contient ce qui suit :

a) le numéro d'enregistrement du groupe attribué par le ministre en vertu du paragraphe 4(3);

b) une attestation que la déclaration est véridique et complète.

31 décembre

(2) La déclaration est transmise au ministre au plus tard le 31 décembre de l'année civile précédant celle de l'application de l'interdiction prévue au paragraphe 6(1) au groupe.

Exemptions

(3) La déclaration a pour effet d'exempter la personne responsable de l'application des articles 6 à 24.

Rapport abrégé

(4) La personne responsable d'un groupe à l'égard duquel une déclaration a été transmise au ministre transmet à celui-ci un rapport abrégé contenant les renseignements visés aux articles 1 et 2 de l'annexe 2 et les données sur le solde exportateur du groupe pour l'année civile au plus tard le 1er juin qui suit l'année civile faisant l'objet du rapport.

Fin des exemptions

(5) Sous réserve du paragraphe (6), les exemptions visées au paragraphe (3) deviennent inapplicables au groupe si le solde exportateur du groupe est supérieur à zéro GWh au cours de toute année civile.

Exemption en cas d'urgence

(6) Si le solde exportateur du groupe est supérieures à zéro GWh au cours d'une année civile en raison de la quantité d'électricité qu'il exporte au cours d'une période visée

Minister has issued an exemption for that unit under section 19 or an extension under section 20, the exemptions set out in subsection (3) will continue to apply.

Prohibition

Prohibition

6 (1) A responsible person, for a unit with respect to which net exports are greater than 0 GWh during a calendar year, must not emit CO_2 from the unit, from the combustion of fossil fuel, that has on average during that calendar year an emission intensity of more than 30 tonnes of CO_2 emissions/GWh of electricity generated, determined in accordance with sections 7 to 18, as applicable.

Exception — carbon capture and storage

(2) Despite subsection (1), a responsible person, for a unit with respect to which net exports are greater than 0 GWh, may, until December 31, 2039, emit from the unit CO_2 from the combustion of fossil fuel that has, on average during the calendar year, an emission intensity no more than 40 tonnes of CO_2 emissions/GWh of electricity generated, determined in accordance with sections 7 to 18, as applicable, if

(a) the unit includes a carbon capture and storage system that started operating within the last seven calendar years; and

(b) the responsible person for that unit has submitted, with the annual report, documentation demonstrating that the unit operated at or below 30 tonnes of CO_2 emissions/GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in the calendar year for which the annual report is submitted.

Exception — hours

(3) Despite subsection (1), a responsible person may, for a unit that has not combusted coal during the calendar year and with respect to which net exports are greater than 0 GWh, emit from that unit up to 150 kilotonnes of CO_2 in a calendar year, determined in accordance with section 8, if the unit operates for 450 hours or less during that calendar year, not including any hours the unit operates and CO_2 the unit emits during a period for which the Minister has issued an exemption under section 19 or an extension under section 20.

par une exemption accordée par le ministre en application de l’article 19 ou prolongée par celui-ci en application de l’article 20, les exemptions visées au paragraphe (3) continuent à s’appliquer.

Interdiction

Interdiction

6 (1) Il est interdit à la personne responsable d’un groupe dont le solde exportateur est supérieur à zéro GWh au cours d’une année civile de rejeter du CO_2 provenant de la combustion de combustibles fossiles par le groupe dont l’intensité d’émission est supérieure à 30 tonnes d’émissions de CO_2/GWh d’électricité produite en moyenne au cours de cette année civile, celle-ci étant déterminée conformément aux articles 7 à 18 selon le cas.

Exception — captage et stockage de carbone

(2) Malgré le paragraphe (1), la personne responsable d’un groupe dont le solde exportateur est supérieur a zéro GWh au cours d’une année civile donnée peut, au plus tard le 31 décembre 2039, rejeter du CO_2 provenant de la combustion de combustibles fossiles par le groupe dont l’intensité d’émission est inférieure ou égale à 40 tonnes d’émissions de CO_2/GWh d’électricité produite, intensité déterminée aux termes des articles 7 à 18, selon le cas, si :

a) le groupe comprend un système de captage et de stockage de carbone qui a commencé à fonctionner il y a au plus sept ans;

b) la personne responsable transmet, avec le rapport annuel, les documents établissant que le groupe a fonctionné, au cours de l’année civile faisant l’objet du rapport annuel, à une intensité inférieure ou égale à 30 tonnes d’émissions de CO_2/GWh pendant deux périodes d’au moins douze heures consécutives, ces périodes étant séparées d’au moins quatre mois.

Exception — heures

(3) Malgré le paragraphe (1), la personne responsable d’un groupe qui n’a pas brûlé de charbon au cours de l’année civile et qui a solde exportateur supérieur à zéro GWh peut rejeter une quantité maximale de 150 kilotonnes de CO_2, celle-ci étant déterminée conformément à l’article 8, si le groupe fonctionne pendant au plus 450 heures au cours de cette année civile, compte non tenu des émissions produites et du nombre d’heures de fonctionnement du groupe au cours de toute période visée par une exemption accordée par le ministre en application de l’article 19 ou prolongée par celui-ci en application de l’article 20 .

Start of prohibition

(4) The responsible person for a unit must meet the emission intensity limit set out in subsection (1), beginning

(a) January 1, 2035, with respect to a unit that

(i) has a commissioning date on or after January 1, 2025,

(ii) has increased its electricity generation capacity by 10% or more since submitting the registration report for the unit, or

(iii) combusts coal;

(b) in the case of a boiler unit referred to in subsection 3(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, the later of

(i) January 1 of the calendar year the prohibition set out in subsection 4(2) of those Regulations begins to apply to the unit, as determined under that subsection; or

(ii) January 1, 2035, or

(c) January 1 of the calendar year following the unit's end of prescribed life, with respect to all other units.

Definition — prescribed life

(5) For the purposes of paragraph (4)(c), prescribed life means the period that begins on the commissioning date and ends on the later of

(a) December 31 of the calendar year that is 20 years after the commissioning date, and

(b) December 31, 2034.

Quantification

Emission Intensity

Emission intensity

7 (1) The emission intensity of a unit is determined by the formula

$$E \div G$$

where

E is the quantity of CO_2 emissions attributed to a unit, during the calendar year, expressed in tonnes, determined in accordance with section 8; and

Début de l'interdiction

(4) La personne responsable est tenue de respecter la limite d'intensité d'émission prévue au paragraphe (1) à compter :

a) du 1er janvier 2035 dans le cas d'un groupe qui est dans l'une ou l'autre des situations suivantes :

(i) il est mis en service le 1er janvier 2025 ou après cette date,

(ii) il a augmenté sa capacité de production d'électricité de 10 % ou plus depuis la date d'envoi du rapport d'enregistrement,

(iii) il brûle du charbon;

b) dans le cas d'un groupe chaudière visé au paragraphe 3(4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*, la plus tardive des dates suivantes :

(i) le 1er janvier de l'année à partir de laquelle l'interdiction prévue au paragraphe 4(2) du même règlement s'applique au groupe, celle-ci étant déterminée aux termes de ce paragraphe,

(ii) le 1er janvier 2035;

c) dans les autres cas, du 1er janvier de l'année civile suivant celle au cours de laquelle la vie réglementaire du groupe prend fin.

Définition — vie réglementaire

(5) Pour l'application de l'alinéa (4)c), vie réglementaire s'entend de la période commençant à la date de mise en service du groupe et se terminant à la plus tardive des dates suivantes :

a) le 31 décembre de l'année civile qui tombe vingt ans après la date de mise en service;

b) le 31 décembre 2034.

Quantification

Intensité des émissions

Intensité des émissions

7 (1) L'intensité des émissions d'un groupe est déterminée conformément à la formule suivante :

$$E \div G$$

où :

E représente la quantité d'émissions de CO_2, exprimée en tonnes, attribuée à un groupe au cours de l'année civile, déterminée conformément à l'article 8;

G is the quantity of electricity generated by the unit during the calendar year, expressed in GWh, determined in accordance with subsection 18(1).

Negative number

(2) For the purposes of the formula in subsection (1), 0 should be used for the element E if the determination under section 8 results in a negative number.

Quantity of CO_2 Emissions

Quantification Methods

Quantification of emissions

8 (1) The quantity of CO_2 emissions attributed to a unit during the calendar year is determined by the formula

$$E_u - E_{th} - E_{ccs} + E_{ext} - E_{ec}$$

where

E_u is the quantity of CO_2 emissions, expressed in tonnes, during the calendar year from the combustion of fossil fuel in the unit, as determined in accordance with subsection (3) and, as applicable, section 9, 10 or 13;

E_{th} is the quantity of CO_2 emissions, expressed in tonnes, attributable to the production of useful thermal energy by the unit, during the calendar year, calculated in accordance with section 15;

E_{ccs} is the quantity of CO_2 captured from the unit during the calendar year and stored in a storage project, expressed in tonnes, determined in accordance with section 16;

E_{ext} is the quantity of CO_2 emitted from the production of the hydrogen fuel or the purchased or transferred steam used by the unit to generate electricity, during the calendar year, expressed in tonnes, determined in accordance with section 17; and

E_{ec} is the quantity of CO_2 emitted from the unit during any period in the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20, expressed in tonnes, determined in accordance with subsection (2).

Calculation of E_{ec}

(2) The element E_{ec} is the difference between the sum of E_u and E_{ext} and the sum of E_{th} and E_{ccs} calculated in accordance with sections 9, 10, 13, 15 to 17 and 19, as applicable, but the reference to calendar year is replaced with the period during the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20.

G la quantité d'électricité, exprimée en GWh, produite par le groupe au cours de l'année civile, déterminée conformément au paragraphe 18(1) .

Valeur négative

(2) Il est entendu que si le résultat de la détermination de la variable E dans la formule prévue au paragraphe (1) en application de l'article 8 est une valeur négative, elle est alors zéro.

Quantité d'émissions de CO_2

Méthodes de quantification

Quantification des émissions

8 (1) La quantité d'émissions de CO_2 attribuée à un groupe au cours de l'année civile est déterminée conformément à la formule suivante :

$$E_g - E_{th} - E_{csc} + E_{ext} - E_{su}$$

où :

E_g représente la quantité d'émissions de CO_2, exprimée en tonnes, provenant de la combustion de combustibles fossiles par le groupe, au cours de l'année civile, et déterminée conformément au paragraphe (3) et, selon le cas, à l'article 9, 10 ou 13;

E_{th} la quantité d'émissions de CO_2, exprimée en tonnes, attribuée à la production d'énergie thermique utile par le groupe, au cours de l'année civile, et déterminée en application de l'article 15;

E_{csc} la quantité de CO_2, exprimée en tonnes, captée à partir du groupe, au cours de l'année civile, et déterminée conformément à l'article 16;

E_{ext} la quantité de CO_2, exprimée en tonnes, provenant de la production d'hydrogène ou de vapeur qui est utilisé par le groupe pour produire de l'électricité, au cours de l'année civile, déterminée conformément à l'article 17;

E_{su} la quantité de CO_2, exprimée en tonnes, émise par le groupe au cours d'une période, pendant l'année civile, visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20, et déterminée conformément au paragraphe (2).

Calcul de la variable E_{su}

(2) La variable E_{su} représente la différence entre la somme des variables E_g et E_{ext} et la somme des variables E_{th} et E_{csc} calculée conformément aux articles 9, 10, 13, 15 à 17 et 19, selon le cas, calcul dans lequel l'année civile est remplacée par la période au cours de celle-ci qui est visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20.

Quantification method for E_u

(3) The quantity of CO_2 emissions resulting from the combustion of fossil fuel in a unit in a calendar year (E_u) must be determined in accordance with

(a) section 9, in the case of a unit that combusted fuel from a coal gasification system during the calendar year;

(b) section 10, in the case of a unit that combusted biomass and combusted fuel from a coal gasification system during the calendar year;

(c) section 13, in the case of a unit that combusted biomass, but did not combust fuel from a coal gasification system, during the calendar year; and

(d) section 9 or 13, in any other case.

Carbon capture and storage

(4) For the purposes of the element E_{ccs} in subsections (1) and (2), the quantity of CO_2 may only be included in that description if it has been permanently stored in a storage project that meets the following criteria:

(a) the geological site into which the CO_2 is injected is

(i) a deep saline aquifer for the sole purpose of storage of CO_2, or

(ii) a depleted oil reservoir for the purpose of enhanced oil recovery; and

(b) the CO_2 stored for the purposes of the project is captured, transported and stored in accordance with the laws applicable to Canada or a province or applicable to the United States or one of its states.

Continuous Emission Monitoring System

Quantification with CEMS

9 Subject to section 11, for the purposes of paragraph 8(3)(a), the quantity of CO_2 emissions must be measured using a CEMS and determined in accordance with Sections 7.1 to 7.7 of the Reference Method. This also applies with respect to a responsible person that, in accordance with paragraph 8(3)(d), opts to quantify emissions in accordance with this section.

Méthodes de quantification pour E_g

(3) La quantité d'émissions de CO_2 provenant de la combustion de combustibles fossiles attribuée à un groupe au cours d'une année civile (E_g) est déterminée, selon le cas :

a) conformément à l'article 9 si le groupe a brûlé du combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

b) conformément à l'article 10 si le groupe a brûlé à la fois de la biomasse et du combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

c) conformément à l'article 13 si le groupe a brûlé de la biomasse et n'a pas brûlé de combustible provenant d'un système de gazéification de charbon au cours de l'année civile;

d) soit conformément aux articles 9 ou 13 dans tout autre cas.

Captage et de stockage de carbone

(4) Seule peut être comptabilisée sous la variable E_{csc} visée aux paragraphes (1) et (2) la quantité de CO_2 stockée de façon permanente dans le cadre d'un projet de stockage qui respecte les critères suivants :

a) le CO_2 est injecté dans un site de stockage géologique :

(i) soit dans le seul but de le stocker dans un aquifère salin profond,

(ii) soit dans le but de permettre la récupération assistée d'hydrocarbures dans un gisement de pétrole épuisé;

b) le CO_2 stocké aux fins du projet est capté, transporté et stocké conformément aux lois fédérales ou provinciales applicables ou aux lois applicables des États-Unis ou de l'un de ses États.

Système de mesure et d'enregistrement en continu des émissions

Mesure à l'aide d'un SMECE

9 Sous réserve de l'article 11, pour l'application de l'alinéa 8(3)a), la quantité d'émissions de CO_2 est mesurée à l'aide d'un SMECE et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence. Il en est de même pour l'application de l'alinéa 8(3)d) lorsque la personne responsable choisit de mesurer la quantité d'émissions conformément au présent article.

Unit combusting biomass

10 (1) Subject to section 11, for the purposes of paragraph 8(3)(b), the quantity of CO_2 emissions must be quantified using a CEMS and must be determined by the formula

$$E_{comb} \times (V_{ff} \div V_T) - E_s$$

where

E_{comb} is the quantity of CO_2 emissions from the unit, expressed in tonnes, during the calendar year from the combustion of fossil fuel and biomass, as measured by the CEMS, and calculated in accordance with Sections 7.1 to 7.7 of the Reference Method;

V_{ff} is the volume of CO_2 emissions released from the combustion of fossil fuel in the unit during the calendar year, expressed in m^3, at standard conditions, and determined by the formula

$$\sum_{i=1}^{n} Q_i \times F_{c,i} \times HHV_i$$

where

i is the i^{th} fossil fuel type combusted in the unit during the calendar year, where "i" goes from 1 to n and where n is the number of fossil fuels so combusted,

Q_i is the quantity of fossil fuel type "i" combusted in the unit during the calendar year, determined

(a) for a gaseous fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 14(1)(a) and expressed in m^3 at standard conditions,

(b) for a liquid fuel, in the same manner used in the determination of V_f in the formula set out in paragraph 14(1)(b) and expressed in kL, and

(c) for a solid fuel, in the same manner used in the determination of M_f in the formula set out in paragraph 14(1)(c) and expressed in tonnes,

$F_{c,i}$ is the fuel-specific carbon-based F-factor for each fossil fuel type "i" — either the factor set out in Appendix A of the Reference Method, or for fuels not listed, the one determined in accordance with that Appendix — corrected to be expressed in m^3, at standard conditions, of CO_2/GJ, and

HHV_i is the higher heating value for each fossil fuel type "i" that is measured in accordance with subsection (2), or the default higher heating value, set out in column 2 of Schedule 3, for the fuel type, as set out in column 1;

Groupe brûlant de la biomasse

10 (1) Sous réserve de l'article 11, pour l'application de l'alinéa 8(3)b), la quantité d'émissions de CO_2 d'un groupe est mesurée à l'aide d'un SMECE et calculée conformément à la formule suivante :

$$E_{comb} \times (V_{cf} \div V_t) - E_s$$

où :

E_{comb} représente la quantité d'émissions de CO_2, exprimée en tonnes, par le groupe au cours de l'année civile, provenant de la combustion de combustibles fossiles et de biomasse, mesurée par le SMECE et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence;

V_{cf} le volume d'émissions de CO_2 provenant de la combustion des combustibles fossiles par le groupe au cours de l'année civile, exprimé en m^3, mesuré dans des conditions normales et déterminé conformément à la formule suivante :

$$\sum_{i=1}^{n} Q_i \times F_{c,i} \times HHV_i$$

où :

i représente le i^e type de combustible fossile brûlé par le groupe au cours de l'année civile , où « i » est un chiffre de 1 à n, « n » étant le nombre de ces combustibles,

Q_i la quantité de combustible fossile de type « i » brûlé par le groupe au cours de l'année civile, déterminée, selon le cas :

a) pour les combustibles gazeux, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)a), cette quantité étant exprimée en m^3 et mesurée dans des conditions normales,

b) pour les combustibles liquides, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)b), cette quantité étant exprimée en kL,

c) pour les combustibles solides, de la même façon que la variable M_c dans la formule prévue à l'alinéa 14(1)c), cette quantité étant exprimée en tonnes,

$F_{c,i}$ le facteur de carbone propre à chaque combustible fossile de type « i », celui-ci étant le facteur prévu à l'annexe A de la méthode de référence ou, à défaut, celui qui est déterminé conformément à cette annexe, corrigé pour être exprimé en m^3 de CO_2/GJ mesuré dans des conditions normales,

V_T is the volume of CO_2 emissions released from combustion of fossil fuel and biomass in the unit during the calendar year determined by the formula

$$\sum_{t=1}^{n}[0.01 \times CO_{2w,t} \times Q_{w,t}]$$

where

t is the tth hour, where “t” goes from 1 to n and where n is the total number of hours during which the unit generated electricity in the calendar year,

$CO_{2w,t}$ is the average concentration of CO_2 in relation to all gases in the stack emitted from the combustion of fuel in the unit during each hour “t”, during which the unit generated electricity in the calendar year — or, if applicable, a calculation made in accordance with Section 7.4 of the Reference Method of that average concentration of CO_2 based on a measurement of the concentration of oxygen (O_2) in those gases in the stack — expressed as a percentage on a wet basis, and

$Q_{w,t}$ is the average volumetric flow during that hour, measured on a wet basis by the stack gas volumetric flow monitor, expressed in m^3, at standard conditions; and

E_s is the quantity of CO_2 emissions, expressed in tonnes, that is released from the use of sorbent to control the emission of sulphur dioxide from the unit during the calendar year, determined by the formula

$$S \times R \times (44 \div MM_s)$$

where

S is the quantity of sorbent material, such as calcium carbonate ($CaCO_3$), expressed in tonnes,

R is the stoichiometric ratio, on a mole fraction basis, of CO_2 released on usage of one mole of sorbent material, which is equal to 1 if the sorbent material is $CaCO_3$, and

MM_s is the molecular mass of the sorbent material, which is equal to 100 if the sorbent material is $CaCO_3$.

HHV_i le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « i », celui-ci étant déterminé conformément au paragraphe (2) ou le pouvoir calorifique supérieur par défaut mentionné à la colonne 2 de l’annexe 3 pour le type de combustible visé à la colonne 1;

V_t le volume d’émissions de CO_2 provenant de la combustion de combustibles fossiles et de biomasse par le groupe au cours de l’année civile, déterminé conformément à la formule suivante :

$$\sum_{t=1}^{n}[0{,}01 \times CO_{2h,t} \times Q_{h,t}]$$

où :

t représente la t^{e} heure, où « t » est un chiffre de 1 à n, « n » étant le nombre total d’heures durant lesquelles le groupe a produit de l’électricité au cours de l’année civile,

$CO_{2h,t}$ la concentration moyenne d’émissions de CO_2 par rapport à la totalité des gaz de cheminée provenant de la combustion de combustibles par le groupe pour chaque heure « t » de production d’électricité au cours de l’année civile — ou, le cas échéant, le résultat du calcul effectué conformément à l’article 7.4 de la méthode de référence à partir d’une mesure de la concentration d’oxygène (O_2) dans ces gaz de cheminée —, exprimée en pourcentage de CO_2 sur une base humide,

$Q_{h,t}$ le débit volumétrique moyen durant l’heure en cause, exprimé en m^3 et mesuré dans des conditions normales sur une base humide par un appareil de mesure du débit volumétrique placé sur la cheminée;

E_s la quantité, exprimée en tonnes, d’émissions de CO_2 provenant du sorbant utilisé pour contrôler les émissions de dioxyde de soufre par le groupe au cours de l’année civile, calculée conformément à la formule suivante :

$$S \times R \times (44 \div MM_s)$$

où :

S représente la quantité de sorbant — notamment le carbonate de calcium ($CaCO_3$) —, exprimée en tonnes,

R le rapport stœchiométrique — selon la fraction molaire — de CO_2 attribuable à une mole de sorbant, lequel est 1 si le sorbant est du $CaCO_3$,

MM_s la masse moléculaire du sorbant, laquelle est 100 si le sorbant est du $CaCO_3$.

Higher heating value

(2) The higher heating value of a fuel is to be measured

(a) for a gaseous fuel,

(i) in accordance with the following standards, as applicable

(A) ASTM D1826-94(2017), entitled *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*,

(B) ASTM D3588-98(2017), entitled *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*,

(C) ASTM D4891-13, entitled *Standard Test Method for Heating Value of Gases in Natural Gas and Flare Gases Range by Stoichiometric Combustion*,

(D) Gas Processors Association Standard 2172 - 14, entitled *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*, and

(E) Gas Processors Association Standard 2261 - 13, entitled *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*, or

(ii) by means of a direct measuring device that measures the higher heating value of the fuel, but if the measuring device provides only lower heating values, those lower heating values must be converted to higher heating values; and

(b) for a liquid fuel that is

(i) an oil or a liquid fuel derived from waste, in accordance with

(A) ASTM D240-17, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*, or

(B) ASTM D4809-13, entitled *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*, and

(ii) any other liquid fuel type, in accordance with an applicable ASTM standard for the measurement of the higher heating value of the fuel type or, if no such ASTM standard applies, in accordance with an applicable internationally recognized method.

Pouvoir calorifique supérieur

(2) Le pouvoir calorifique supérieur d'un combustible est déterminé :

a) dans le cas des combustibles gazeux :

(i) soit conformément à l'une ou l'autre des normes ci-après applicable au combustible en cause :

(A) la norme ASTM D1826-94(2017) intitulée *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*,

(B) la norme ASTM D3588-98(2017) intitulée *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*,

(C) la norme ASTM D4891-13 intitulée *Standard Test Method for Heating Value of Gases in Natural Gas and Flare Gases Range by Stoichiometric Combustion*,

(D) la norme 2172-14 de la Gas Processors Association intitulée *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*,

(E) la norme 2261-13 de la Gas Processors Association intitulée *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*,

(ii) soit à l'aide d'un instrument de mesure directe, mais s'il ne détermine que le pouvoir calorifique inférieur, celui-ci est converti en pouvoir calorifique supérieur;

b) dans le cas des combustibles liquides :

(i) s'agissant d'huiles et de dérivés de déchets, conformément à l'une ou l'autre des normes suivantes :

(A) la norme ASTM D240-17 intitulée *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter*,

(B) la norme ASTM D4809-13 intitulée *Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)*,

(ii) s'agissant d'autres combustibles liquides, conformément à la norme ASTM applicable au type de combustible en cause ou, en l'absence d'une telle norme, conformément à toute méthode applicable qui est reconnue à l'échelle internationale.

Multiple CEMS per unit

11 (1) For the purposes of sections 9 and 10, the total quantity of CO_2 emissions from a unit equipped with multiple CEMS is determined by adding together the quantity of CO_2 emissions measured for each CEMS.

Units sharing common stack

(2) If a unit is located at a facility where there is one or more other units and a CEMS measures emissions from that unit and other units at a common stack rather than at the exhaust duct of that unit and of each of those other units that brings those emissions to the common stack, then the quantity of emissions attributable to that unit is determined based on the ratio of the heat input of that unit to the total of the heat input of that unit and of all of those other units sharing the common stack in accordance with the formula

$$\left[\frac{\sum_{j=1}^{y} Q_{u,j} \times HHV_{u,j}}{\sum_{i=1}^{x}\sum_{j=1}^{y} Q_{i,j} \times HHV_{i,j}}\right] \times E$$

where

$Q_{u,j}$ is the quantity of fuel type "j" combusted in that unit "u" during the calendar year, determined

(a) for a gaseous fuel, in the same manner as the one used in the determination of V_f in the formula set out in paragraph 14(1)(a) and expressed in m^3 at standard conditions,

(b) for a liquid fuel, in the same manner as the one used in the determination of V_f in the formula set out in paragraph 14(1)(b) and expressed in kL, and

(c) for a solid fuel, in the same manner as the one used in the determination of M_f in the formula set out in paragraph 14(1)(c) and expressed in tonnes;

$HHV_{u,j}$ is the higher heating value for each fossil fuel type "j" that is combusted in that unit "u" that is measured in accordance with subsection 10(2), or the default higher heating value, set out in column 2 of Schedule 3, for the fuel type, as set out in column 1;

j is the j^{th} fuel type combusted during the calendar year in a unit where "j" goes from 1 to y and where y is the number of those fuel types;

$Q_{i,j}$ the quantity of fuel type "j" combusted in each unit "i" during the calendar year, determined for a gaseous fuel, a liquid fuel and a solid fuel, respectively, in the manner set out in the description of $Q_{u,j}$;

$HHV_{i,j}$ is the higher heating value for each fossil fuel type "j" that is combusted in that unit "i" that is measured in accordance with subsection 10(2), or the default higher heating value, set out in

Plusieurs SMECE par groupe

11 (1) Pour l'application des articles 9 et 10, la quantité totale d'émissions de CO_2 par tout groupe doté de plusieurs SMECE est égale à la somme des quantités d'émissions de CO_2 mesurées pour chaque SMECE.

Plusieurs groupes utilisant une cheminée commune

(2) Si le groupe est situé à une installation où sont situés un ou plusieurs autres groupes, et qu'un SMECE est utilisé pour mesurer les émissions de ce groupe et celles d'autres groupes au point de rejet d'une cheminée commune plutôt qu'au conduit d'évacuation de chacun de ces groupes vers la cheminée commune, la quantité d'émissions attribuable au groupe en cause est calculée en fonction de la proportion de l'apport de chaleur du groupe en cause par rapport à celui de l'ensemble des groupes qui utilisent la cheminée commune, conformément à la formule suivante :

$$\left[\frac{\sum_{j=1}^{y} Q_{g,j} \times HHV_{g,j}}{\sum_{i=1}^{x}\sum_{j=1}^{y} Q_{i,j} \times HHV_{i,j}}\right] \times E$$

où :

$Q_{g,j}$ représente la quantité de combustible fossile de type « j » brûlé par le groupe en cause « g » au cours de l'année civile en cause, déterminée :

a) pour les combustibles gazeux, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)a), cette quantité étant exprimée en m^3 et mesurée dans des conditions normales,

b) pour les combustibles liquides, de la même façon que la variable V_c dans la formule prévue à l'alinéa 14(1)b), cette quantité étant exprimée en kL,

c) pour les combustibles solides, de la même façon que la variable M_c dans la formule prévue à l'alinéa 14(1)c), cette quantité étant exprimée en tonnes;

$HHV_{g,j}$ le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « j » brûlé par le groupe « g », celui-ci étant déterminé conformément au paragraphe 10(2) ou mentionné à la colonne 2 de l'annexe 3 pour le type de combustible visé à la colonne 1;

j le j^e type de combustible brûlé au cours de l'année civile par le groupe, où « j » est un chiffre de 1 à y, « y » étant le nombre de types de combustible;

$Q_{i,j}$ la quantité de combustible du type « j » brûlé par chaque groupe « i » au cours de l'année civile, déterminée pour les combustibles gazeux, les combustibles liquides et les combustibles solides, respectivement, de la manière prévue pour la variable $Q_{g,j}$;

$HHV_{i,j}$ le pouvoir calorifique supérieur pour chaque type de combustible fossile de type « j » brûlé column 2 of Schedule 3, for the fuel type, as set out in column 1;

i is the i^{th} unit, where “i” goes from 1 to x, and where x is the number of units that share a common stack; and

E is the quantity of CO_2 emissions, expressed in tonnes, from the combustion of all fuels in all the units that share a common stack during the calendar year, measured by a CEMS at the common stack, and calculated in accordance with Sections 7.1 to 7.7 of the Reference Method.

If using CEMS

12 (1) If a CEMS is being used to measure CO_2 emissions, the responsible person must ensure that the requirements set out in the Reference Method are met.

Certification of CEMS

(2) The responsible person must certify the CEMS in accordance with Section 5 of the Reference Method, before it is used for the purposes of these Regulations.

Auditor’s report

(3) For each calendar year during which the responsible person used a CEMS, they must obtain a report, signed by the auditor, that contains the information required by Schedule 4 and submit that report to the Minister with the annual report referred to in subsection 24(1).

Fuel-based Method

Quantification

13 The quantity of CO_2 emissions resulting from the combustion of fossil fuels in a unit in a calendar year is determined by the formula

$$\sum_{i=1}^{n} E_i + E_s$$

where

i is the i^{th} fossil fuel type that is combusted in the calendar year in a unit, where “i” goes from 1 to n and where n is the number of those fossil fuel types;

E_i is the quantity of CO_2 emissions that is attributable to the combustion of fossil fuels of type “i” in the unit in the calendar year, expressed in tonnes, as determined for that fuel type in accordance with section 14; and

par chaque groupe « i », celui-ci étant déterminé conformément au paragraphe 10(2) ou mentionné à la colonne 2 de l’annexe 3 pour le type de combustible visé à la colonne 1;

i le i^e groupe, où « i » est un chiffre de 1 à x, « x » étant le nombre de groupes qui utilisent la cheminée commune;

E la quantité, exprimée en tonnes, d’émissions de CO_2 provenant de la combustion de tous les combustibles par tous les groupes qui utilisent la cheminée commune au cours de l’année civile, mesurée par un SMECE installé à la cheminée commune et calculée conformément aux sections 7.1 à 7.7 de la méthode de référence.

Utilisation d’un SMECE

12 (1) La personne responsable qui utilise un SMECE pour mesurer les émissions de CO_2 veille à ce que les exigences prévues dans la méthode de référence soient suivies.

Homologation du SMECE

(2) La personne responsable homologue le SMECE conformément à la section 5 de la méthode de référence avant son utilisation pour l’application du présent règlement.

Rapport du vérificateur

(3) Pour chaque année civile au cours de laquelle la personne responsable a utilisé un SMECE, elle obtient un rapport comportant les renseignements requis à l’annexe 4, signé par le vérificateur, et le transmet au ministre avec le rapport annuel prévu au paragraphe 24(1).

Quantification fondée sur le combustible brûlé

Quantification

13 La quantité d’émissions de CO_2 provenant de la combustion de combustibles fossiles par un groupe, au cours d’une année civile, est calculée conformément à la formule suivante :

$$\sum_{i=1}^{n} E_i + E_s$$

où :

i représente le i^e type de combustible fossile brûlé par le groupe au cours de l’année civile, où « i » est un chiffre de 1 à n, « n » étant le nombre de types de combustible fossile brûlé;

E_i la quantité d’émissions de CO_2, exprimée en tonnes, qui est attribuable à la combustion de combustibles

E_s is the quantity of CO_2 emissions that is released from the sorbent used to control the emission of sulphur dioxide from the unit in the calendar year, expressed in tonnes, as determined by the formula

$$S \times R \times (44 \div MM_s)$$

where

S is the quantity of sorbent material, such as calcium carbonate ($CaCO_3$), expressed in tonnes,

R is the stoichiometric ratio, on a mole fraction basis, of CO_2 released on usage of 1 mole of sorbent material, which is equal to 1 if the sorbent material is $CaCO_3$, and

MM_s is the molecular mass of the sorbent material, which is equal to 100 if the sorbent material is $CaCO_3$.

Measured carbon content

14 (1) The quantity of CO_2 emissions that is attributable to the combustion of a fossil fuel in a unit in a calendar year is determined by one of the following formulas, as applicable

(a) for a gaseous fuel,

$$V_f \times CC_A \times (MM_A \div MV_{cf}) \times 3.664 \times 0.001$$

where

V_f is the volume of the fuel combusted in the calendar year, determined using flow meters, expressed in m^3, at standard conditions,

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), expressed in kg of carbon per kg of the fuel,

MM_A is the average molecular mass of the fuel, determined based on fuel samples taken in accordance with section 21, expressed in kg per kg-mole of the fuel, and

MV_{cf} is the molar volume conversion factor of 23.645 m^3, at standard conditions, per kg-mole of the fuel at standard conditions;

(b) for a liquid fuel,

$$V_f \times CC_A \times 3.664$$

where

V_f is the volume of the fuel combusted in the calendar year, determined using flow meters, expressed in kL, and

fossiles de type « i » par le groupe au cours de l'année civile et qui est calculée selon le type de combustible conformément à l'article 14;

E_s la quantité d'émissions de CO_2, exprimée en tonnes, qui provient du sorbant utilisé pour contrôler les émissions de dioxyde de soufre par le groupe au cours de l'année civile et qui est calculée conformément à la formule suivante :

$$S \times R \times (44 \div MM_s)$$

où :

S représente la quantité de sorbant — tel que le carbonate de calcium ($CaCO_3$) —, exprimée en tonnes,

R le rapport stœchiométrique — selon la fraction molaire — de CO_2 attribuable à une mole de sorbant, lequel est de 1 si le sorbant est du $CaCO_3$,

MM_s la masse moléculaire du sorbant, laquelle est de 100 si le sorbant est du $CaCO_3$.

Contenu en carbone mesuré

14 (1) La quantité d'émissions de CO_2 qui est attribuable à la combustion de combustibles fossiles par le groupe au cours d'une année civile est calculée conformément à celle des formules ci-après qui s'applique :

a) dans le cas de combustibles gazeux :

$$V_c \times CC_M \times (MM_M \div MV_{fc}) \times 3{,}664 \times 0{,}001$$

où :

V_c représente le volume du combustible brûlé au cours de l'année civile, exprimé en m^3 et mesuré dans des conditions normales et déterminé à l'aide de débitmètres,

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en kg de carbone par kg de combustible, calculée conformément au paragraphe (2),

MM_M la masse moléculaire moyenne du combustible, exprimée en kg par kg-mole de combustible, déterminée à partir des échantillons de combustible prélevés conformément à l'article 21,

MV_{fc} le facteur de conversion du volume molaire, soit 23,645 m^3, mesuré dans des conditions normales, par kg-mole de combustible mesuré dans des conditions normales;

b) dans le cas de combustibles liquides :

$$V_c \times CC_M \times 3{,}664$$

où :

V_c représente le volume du combustible brûlé au cours de l'année civile, exprimé en kL et déterminé à l'aide de débitmètres,

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), at the same temperature as that used in the determination of V_f, expressed in tonnes of carbon per kL of the fuel; and

(c) for a solid fuel,

$$M_f \times CC_A \times 3.664$$

where

M_f is the mass of the fuel combusted in the calendar year, determined, as the case may be, on a wet or dry basis using a measuring device, expressed in tonnes, and

CC_A is the weighted average of the carbon content of the fuel, determined in accordance with subsection (2), on the same wet or dry basis as that used in the determination of M_f, expressed in kg of carbon per kg of the fuel.

Weighted average

(2) The weighted average "CC_A" referred to in paragraphs (1)(a) to (c) is determined by the formula

$$\frac{\sum_{i=1}^{n} CC_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

where

CC_i is the carbon content of each sample or composite sample, as the case may be, of the fuel for the i^{th} sampling period, expressed for gaseous fuels, liquid fuels and solid fuels, respectively, in the same unit of measure as that set out in CC_A, as provided by the supplier of the fuel to the responsible person or, if not so provided, as determined by the responsible person in the following manner:

(a) for a gaseous fuel,

(i) in accordance with the following standards for the measurement of the carbon content of the fuel, as applicable

(A) ASTM D1945-14, entitled *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*,

(B) ASTM UOP539-12, entitled *Refinery Gas Analysis by Gas Chromatography*,

(C) ASTM D7833-14, entitled *Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography*, and

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en tonnes de carbone par kL de combustible et calculée conformément au paragraphe (2) à la même température que celle choisie pour déterminer la variable V_c;

c) dans le cas de combustibles solides :

$$M_c \times CC_M \times 3,664$$

où :

M_c représente la masse du combustible brûlé au cours de l'année civile, déterminée, selon le cas, sur une base sèche ou humide, à l'aide d'un instrument de mesure et exprimée en tonnes,

CC_M la moyenne pondérée du contenu en carbone du combustible, exprimée en kg de carbone par kg de combustible et calculée conformément au paragraphe (2) sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable M_c.

Moyenne pondérée

(2) La moyenne pondérée « CC_M » visée aux alinéas (1)a) à c) est calculée conformément à la formule suivante :

$$\frac{\sum_{i=1}^{n} CC_i \times Q_i}{\sum_{i=1}^{n} Q_i}$$

où :

CC_i représente le contenu en carbone de chaque échantillon ou échantillon composite, selon le cas, de combustible pour la i^e période d'échantillonnage, exprimé pour un combustible gazeux, liquide et solide, respectivement, dans la même unité de mesure que celle prévue pour la variable CC_M, qui soit est fourni à la personne responsable par le fournisseur du combustible, ou sinon, qui est établi par la personne responsable de la façon suivante :

a) dans le cas des combustibles gazeux :

(i) soit conformément à l'une des normes applicables ci-après qui permet d'en mesurer le contenu en carbone :

(A) la norme ASTM D1945-14 intitulée *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*,

(B) la norme ASTM UOP539-12 intitulée *Refinery Gas Analysis by Gas Chromatography*,

(C) la norme ASTM D7833-14 intitulée *Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon*

(D) API Technical Report 2572, 1st edition, published in May 2013 and entitled *Carbon Content, Sampling, and Calculation*, or

(ii) by means of a direct measuring device that measures the carbon content of the fuel,

(b) for a liquid fuel, in accordance with the following standards or methods for the measurement of the carbon content of the fuel, as applicable

(i) API Technical Report 2572, 1st edition, published in May 2013 and entitled *Carbon Content, Sampling, and Calculation*,

(ii) ASTM D5291-16, entitled *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*,

(iii) the ASTM standard that applies to the type of fuel, or

(iv) if no ASTM standard applies, an applicable internationally recognized method, and

(c) for a solid fuel, on the same wet or dry basis as that used in the determination of CC_A, in accordance with,

(i) for a solid fuel derived from waste, ASTM E777-08, entitled *Standard Test Method for Carbon and Hydrogen in the Analysis Sample of Refuse-Derived Fuel*, and

(ii) for any other solid fuel, the following standard or method for the measurement of the carbon content of the fuel, as applicable:

(A) the ASTM standard that applies to the type of fuel, and

(B) if no ASTM standard applies, an applicable internationally recognized method;

i is the i^{th} sampling period that is referred to in section 21, where "i" goes from 1 to n and where n is the number of those sampling periods; and

Q_i is the volume or mass, as the case may be, of the fuel combusted during the ith sampling period, expressed

(a) in m^3, at standard conditions, for a gaseous fuel,

(b) in kL for a liquid fuel, and

(c) in tonnes for a solid fuel, on the same wet or dry basis as that used in the determination of CC_A.

Gases in Gaseous Mixtures by Gas Chromatography,

(D) le document intitulé API Technical Report 2572, *Carbon Content, Sampling, and Calculation*, 1re édition, publié en mai 2013,

(ii) soit à l'aide d'un instrument de mesure directe,

b) dans le cas des combustibles liquides, conformément à l'une des normes ou méthodes applicables ci-après qui permet d'en mesurer le contenu en carbone :

(i) le document intitulé API Technical Report 2572, *Carbon Content, Sampling, and Calculation*, 1re édition, publié en mai 2013,

(ii) la norme ASTM D5291-16 intitulée *Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants*,

(iii) la norme ASTM applicable au type de combustible,

(iv) en l'absence d'une norme ASTM, toute méthode applicable qui est reconnue à l'échelle internationale,

c) dans le cas des combustibles solides, sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable CC_M et :

(i) s'agissant de combustibles solides dérivés de déchets, conformément à la norme ASTM E777-08 intitulée *Standard Test Method for Carbon and Hydrogen in the Analysis Sample of Refuse-Derived Fuel*,

(ii) s'agissant d'autres combustibles solides, conformément à la norme ou méthode ci-après qui permet d'en mesurer le contenu en carbone :

(A) la norme ASTM applicable au type de combustible,

(B) en l'absence d'une telle norme, toute méthode applicable qui est reconnue à l'échelle internationale;

i la i^e période d'échantillonnage visée à l'article 21 où « i » est un chiffre de 1 à n, « n » étant le nombre de ces périodes d'échantillonnage;

Q_i le volume ou la masse, selon le cas, du combustible brûlé au cours de la ie période d'échantillonnage, exprimé :

a) exprimé en m^3 et mesuré dans des conditions normales, pour les combustibles gazeux,

b) exprimé en kL, pour les combustibles liquides,

c) exprimé en tonnes, pour les combustibles solides, sur la même base sèche ou humide que celle qui a été choisie pour déterminer la variable CC_M.

Useful Thermal Energy

Emissions – useful thermal energy (E_{th})

15 The quantity of CO_2 emitted by the unit attributable to the production of useful thermal energy by the unit is determined by the formula

$$H_{pnet} \times b_{EI}$$

where

H_{pnet} is the net useful thermal energy, expressed in GJ, determined by the formula:

$$\sum_{t=1}^{x}\left[\sum_{i=1}^{n}\{h_{out\_i} \times M_{out\_i}\} - \sum_{j=1}^{m}\{h_{in\_j} \times M_{in\_j}\}\right]_t$$

where

t is the t^{th} hour, where “t” goes from 1 to x and where x is the total number of hours during which the unit produced useful thermal energy in the calendar year,

i is the i^{th} heat stream exiting the unit, where “i” goes from 1 to n and where n is the total number of heat streams exiting the unit,

h_{out_i} is the average specific enthalpy of the i^{th} heat stream exiting the unit, expressed in GJ/tonne, during period “t” and must be based on the measurement of the temperature and pressure of that heat stream and determined using a continuous measuring device,

M_{out_i} is the mass flow of the i^{th} heat stream exiting the unit, expressed in tonnes, during period “t”, determined using a continuous measuring device,

j is the j^{th} heat stream, other than condensate return, entering the unit, where “j” goes from 1 to m and where m is the total number of heat streams entering the unit,

h_{in_j} is the average specific enthalpy of the j^{th} heat stream, other than condensate return, entering the unit, expressed in GJ/tonne, during period “t” and must be based on the measurement of the temperature and pressure of that heat stream and determined using a continuous measuring device,

M_{in_j} is the mass flow of the j^{th} heat stream, other than condensate return, entering the unit,

Énergie thermique utile

Émissions — énergie thermique utile (E_{th})

15 La quantité des émissions de CO_2 par un groupe qui est attribuable à la production d’énergie thermique utile est déterminée conformément à la formule suivante :

$$H_{pnette} \times b_{EI}$$

où :

H_{pnette} représente la quantité d’énergie thermique utile nette, exprimée en GJ, déterminée conformément à la formule suivante :

$$\sum_{t=1}^{x}\left[\sum_{i=1}^{n}\{h_{sort\_i} \times M_{sort\_i}\} - \sum_{j=1}^{m}\{h_{intr\_j} \times M_{intr\_j}\}\right]_t$$

où :

t représente la te heure, où « t » est un chiffre de 1 à x, « x » étant le nombre total d’heures au cours desquelles le groupe a produit de l’énergie thermique utile au cours de l’année civile,

i le i^{e} flux calorifique sortant du groupe, où « i » est un chiffre de 1 à n, « n » étant le nombre total de flux calorifiques sortants,

h_{sort_i} l’enthalpie spécifique moyenne au cours de la période « t » du ie flux calorifique sortant du groupe, exprimée en GJ/tonne et déterminée au moyen d’un instrument de mesure en continu selon les mesures de la température et de la pression de ce ie flux calorifique,

M_{sort_i} le débit massique au cours de la période « t » du i^{e} flux calorifique sortant du groupe, exprimé en tonnes et déterminé au moyen d’un instrument de mesure en continu,

j le j^{e} flux calorifique, autre que le flux de condensat de retour, entrant dans le groupe, où « j » est un chiffre de 1 à m, « m » étant le nombre total de flux calorifiques entrants,

h_{intr_j} l’enthalpie spécifique moyenne au cours de la période « t » du je flux calorifique, autre que le flux de condensat de retour, entrant dans le groupe, exprimée en GJ/tonne et déterminée au moyen d’un instrument de mesure en continu selon les mesures de la température et de la pression de ce je flux calorifique,

M_{intr_j} le débit massique au cours de la période « t » du je flux calorifique, autre que le flux de expressed in tonnes, during period “t” and determined using a continuous measuring device; and

b_{EI} is the emission intensity of a reference boiler, set to 0.0556 tonnes of CO_2/GJ.

Carbon Capture and Storage

Emissions captured and stored (E_{ccs})

16 The quantity of CO_2 that is captured from the unit during the calendar year and stored in a storage project is determined by the formula

$$E_u \times (E_{cap} \div E_{in})$$

where

E_u is the value of E_u in subsection 8(1);

E_{cap} is the quantity of CO_2 emissions that is the portion of E_{in} that has been captured and subsequently stored, during the calendar year, in a storage project that meets the criteria set out in subsection 8(4), expressed in tonnes, determined by means of direct measuring devices that measure the flow of, and the concentration of CO_2 in, those emissions; and

E_{in} is the quantity of CO_2 emissions, expressed in tonnes, entering the carbon capture and storage system during the calendar year, determined using a CEMS, in accordance with Sections 7.1 to 7.7 of the Reference Method, that measures upstream of the carbon capture and storage system and that measures all emissions entering the carbon capture and storage system.

Hydrogen Fuel and Steam

Quantification of emissions (E_{ext})

17 (1) The quantity of CO_2 emitted from the production of the hydrogen fuel or steam used by the unit to generate electricity is determined by the formula

$$\sum_{k=1}^{n}\left(\left(\frac{E_k}{P_k}\right) \times Q_k\right)$$

where

E_k is the total annual CO_2 emissions that result from the total annual production of hydrogen fuel or from the total annual production of steam, expressed in tonnes, in the calendar year;

P_k is the total annual production of the hydrogen fuel, expressed in m^3 at standard conditions, or steam, expressed in GJ, in a calendar year, determined using a continuous measuring device;

condensat de retour, entrant dans le groupe, exprimé en tonnes et déterminé au moyen d’un instrument de mesure en continu,

b_{EI} l’intensité des émissions d’une chaudière de référence, fixée à 0,0556 tonne CO_2/GJ.

Captage et de stockage de carbone

Émissions captées et stockées (E_{csc})

16 La quantité des émissions de CO_2 qui est captée d’un groupe et stockée dans le cadre d’un projet de stockage au cours d’une année civile est déterminée conformément à la formule suivante :

$$E_g \times (E_{cap} \div E_{in})$$

où :

E_g représente la valeur de la variable E_g visée au paragraphe 8(1);

E_{cap} la quantité d’émissions de CO_2 qui est la portion de E_{in} qui est captée et subséquemment stockée, au cours de l’année civile, par un projet de stockage qui respecte les critères prévus au paragraphe 8(4), exprimée en tonnes et déterminée à l’aide d’une mesure directe de leur débit et de leur concentration en CO_2;

E_{in} la quantité d’émissions de CO_2, exprimée en tonnes, entrant dans le système de captage et de stockage de carbone, au cours de l’année civile, déterminée à l’aide d’un SMECE, conformément aux sections 7.1 à 7.7 de la méthode de référence, situé en amont du système de captage et de stockage de carbone et mesurant toutes les émissions entrant dans ce système .

Hydrogène et vapeur

Quantification des émissions (E_{ext})

17 (1) La quantité des émissions de CO_2 provenant de la production d’hydrogène ou de vapeur utilisé par le groupe pour produire de l’électricité est déterminée conformément à la formule suivante :

$$\sum_{k=1}^{n}\left(\left(\frac{E_k}{P_k}\right) x\, Q_k\right)$$

où :

E_k représente la quantité totale des émissions annuelles de CO_2 provenant de la production annuelle totale d’hydrogène ou de la production annuelle totale de vapeur, exprimée en tonnes, au cours d’une année civile;

P_k la production annuelle totale d’hydrogène, exprimée en m^3 et mesurée dans des conditions normales, ou de vapeur, exprimée en GJ, au cours de l’année civile, déterminée à l’aide d’un dispositif de mesure en continu;

Q_k is the quantity of hydrogen, expressed in m^3 at standard conditions, or purchased or transferred steam, expressed in GJ, used by the unit to generate electricity, during the calendar year, determined using a continuous measuring device; and

k is the k^{th} stream of hydrogen or steam, with "k" going from 1 to n, where n is the number of streams of hydrogen or steam that are used by the unit during the calendar year.

Quantification of E_k and P_k

(2) The responsible person must, if possible, obtain the quantity of E_k and P_k from the supplier of the hydrogen fuel or steam, quantified in accordance with section 10 of the GHGRP with respect to hydrogen production and with section 7 of the GHGRP with respect to electricity and heat production.

Variable R_{CO2}

(3) For the purposes of subsection (2), the description of the element R_{CO2} in Equation 10-2 of the GHGRP must be read as "CO_2 captured and permanently stored in a storage project that meets the criteria set out in paragraphs 8(4)(a) and (b) of these Regulations".

Default value

(4) Despite subsection (2), the responsible person must replace the ratio $E_k \div P_k$ in the formula set out in subsection (1), with 0.08 tonnes of CO_2/GJ for both hydrogen and steam if

(a) the production of hydrogen fuel does not occur at the facility at which the unit is located or the steam is purchased or transferred to the facility at which the unit is located; and

(b) the responsible person is not able to get the information required to determine E_k or P_k from the supplier of the hydrogen fuel or steam.

Quantity of Electricity

Quantity of electricity

18 (1) The quantity of electricity generated by the unit is determined by the formula

$$G_{gross} - G_{ec}$$

where

G_{gross} is the gross quantity of electricity generated by the unit in the calendar year, expressed in GWh, measured at the electrical terminals of the generators of the unit using a meter that has received

Q_k la quantité d'hydrogène, exprimée en m^3 et mesurée dans des conditions normales, ou de vapeur achetée ou transférée, exprimée en GJ, utilisée par le groupe pour produire de l'électricité, au cours de l'année civile, déterminée à l'aide d'un dispositif de mesure en continu;

k le k^e flux d'hydrogène ou de vapeur, où « k » est un nombre de 1 à n, « n » étant le nombre de flux d'hydrogène ou de vapeur utilisés par le groupe, au cours de l'année civile.

Quantification des variables E_k et P_k

(2) La personne responsable obtient, dans la mesure du possible, les valeurs E_k et de P_k du fournisseur d'hydrogène ou de vapeur, lesquelles sont quantifiées conformément à la section 10 de la méthode d'ECCC en ce qui concerne l'hydrogène et conformément à la section 7 de la méthode d'ECCC en ce qui concerne la production d'électricité et de chaleur.

Variable R_{CO2}

(3) Pour l'application du paragraphe (2), la description de la variable R_{CO2} dans l'équation 10–2 de la méthode d'ECCC s'entend de « CO_2 capté et stocké dans un projet de stockage qui remplit les critères énumérés aux alinéas 8(4)a) et b) du présent règlement ».

Valeur par défaut

(4) Malgré le paragraphe (2), la personne responsable remplace le ratio $E_k \div P_k$ dans la formule prévue au paragraphe (1) par la valeur par défaut 0,08 tonne CO_2/GJ pour l'hydrogène et pour la vapeur si :

a) d'une part, la production d'hydrogène n'a pas lieu dans l'installation où se trouve le groupe ou la vapeur est achetée ou transférée à l'installation où se trouve le groupe;

b) d'autre part, la personne responsable n'est pas en mesure d'obtenir les renseignements requis pour déterminer les variables E_k et P_k auprès du fournisseur d'hydrogène ou de vapeur.

Quantité d'électricité

Quantité d'électricité

18 (1) La quantité d'électricité produite par un groupe est calculée conformément à la formule suivante :

$$G_{brute} - G_{su}$$

où :

G_{brute} représente la quantité brute d'électricité produite par le groupe au cours de l'année civile, exprimée en GWh et mesurée aux bornes électriques des générateurs du groupe à l'aide d'un an approval referred to in subsection 9(4) of the *Electricity and Gas Inspection Act*; and

G_{ec} is the gross quantity of electricity generated by the unit during any period during the calendar year for which the Minister has issued an exemption under section 19 or an extension under section 20, expressed in GWh, measured at the electrical terminals of the generators of the unit using a meter that has received an approval referred to in subsection 9(4) of the *Electricity and Gas Inspection Act*.

Meter specifications

(2) The meters referred to in subsection (1) must be installed and used in accordance with the most current electricity specification relating to design, composition, construction and performance of the class, type or design of that meter referred to in subsection 12(1) of the *Electricity and Gas Inspection Regulations*, published on the Measurement Canada website as an electricity specification.

Emergency Circumstances

Application for exemption

19 (1) A responsible person, under an emergency circumstance described in subsection (2), may apply to the Minister for an exemption from subsections 6(1) to (3) in respect of a unit if, as a result of the emergency, the operator of the electricity system in the province in which the unit is located or an official of that province responsible for ensuring and supervising the electricity supply orders the responsible person to produce electricity to avoid a threat to the supply or to restore that supply.

Definition of emergency circumstance

(2) An emergency circumstance is a circumstance

(a) that arises due to an extraordinary, unforeseen and irresistible event; or

(b) under which one or more of the measures referred to in paragraph 1(a) of the *Regulations Prescribing Circumstances for Granting Waivers Pursuant to Section 147 of the Act* has been made or issued in the province where the unit is located.

Application — deadline and content

(3) The application for the exemption must be provided to the Minister within 15 days after the day on which the emergency circumstance arises. The application must include the information referred to in section 1 and paragraphs 2(a) to (d) of Schedule 1 or the unit's registration

compteur à l'égard duquel l'approbation visée au paragraphe 9(4) de la *Loi sur l'inspection de l'électricité et du gaz* a été délivrée;

G_{su} la quantité brute d'électricité produite par le groupe au cours de toute période pendant l'année civile qui est visée par une exemption accordée par le ministre en application de l'article 19 ou prolongée par celui-ci en application de l'article 20, exprimée en GWh et mesurée aux bornes électriques des générateurs du groupe à l'aide d'un compteur à l'égard duquel l'approbation visée au paragraphe 9(4) de la *Loi sur l'inspection de l'électricité et du gaz* a été délivrée.

Normes relatives aux compteurs

(2) Les compteurs visés au paragraphe (1) sont installés et utilisés de manière à ce que soient respectées les normes les plus récentes relatives à la conception, à la composition, à la construction et au fonctionnement auxquelles un compteur ou une catégorie, un type ou un modèle de compteur doit se conformer aux termes du paragraphe 12(1) du *Règlement sur l'inspection de l'électricité et du gaz*, publiées sur le site Internet de Mesures Canada à titre de norme en matière d'électricité.

Situations d'urgence

Demande d'exemption

19 (1) La personne responsable peut, dans une situation d'urgence visée au paragraphe (2), présenter au ministre une demande d'exemption de l'application des paragraphes 6(1) à (3) à l'égard d'un groupe si, en raison de la situation d'urgence, l'exploitant du réseau électrique de la province où le groupe est situé ou un responsable de cette province chargé d'assurer et de surveiller l'approvisionnement en électricité lui ordonne de produire de l'électricité afin de prévenir un danger pour l'approvisionnement en électricité ou de rétablir cet approvisionnement.

Définition de situation d'urgence

(2) Est une situation d'urgence la situation qui résulte de l'une des circonstances suivantes :

a) le cas de force majeure;

b) la circonstance dans laquelle au moins une des mesures visées à l'alinéa 1a) du *Règlement prévoyant les circonstances donnant ouverture à une exemption en vertu de l'article 147 de la Loi* a été prise au préalable dans la province où le groupe est situé.

Délai et contenu de la demande

(3) La demande d'exemption est présentée au ministre dans les quinze jours suivant la date du début de la situation d'urgence. Elle comporte les renseignements visés à l'article 1 et aux alinéas 2a) à d) de l'annexe 1 ou le numéro d'enregistrement du groupe, la date à laquelle la situation number, the date on which the emergency circumstance arose and information, along with supporting documents, to demonstrate that the conditions set out in subsection (1) of this section are met.

Minister's decision

(4) If the Minister is satisfied that the conditions set out in subsection (1) are met, the Minister must, within 30 days after the day on which the application is received, grant the exemption.

Duration of exemption

(5) The exemption becomes effective on the day on which the emergency circumstance arises and ceases to have effect on the earliest of

(a) the 90^{th} day after that day,

(b) the day specified by the Minister,

(c) the day on which the circumstance referred to in paragraph (2)(a) ceases to cause a disruption, or a significant risk of disruption, to the electricity supply in the province where the unit is located, and

(d) the day on which the measure, if any, referred to in paragraph (2)(b) ceases to have effect.

Application for extension of exemption

20 (1) If the conditions set out in subsection 19(1) will continue to exist after the day on which the exemption granted under paragraph 19(4) is to cease to have effect, the responsible person may, before that day, apply to the Minister for an extension of the exemption.

Contents of application

(2) The application must include

(a) the unit's registration number, assigned by the Minister, if applicable;

(b) the day on which the emergency circumstance began; and

(c) information, along with supporting documents that demonstrate that the conditions set out in subsection 19(1) will continue to exist after the day on which the exemption is to cease to have effect.

Minister's decision

(3) If the Minister is satisfied that the condition referred to in paragraph (2)(c) has been demonstrated, the Minister must grant the extension within 15 days after the day on which the application is received.

d'urgence a débuté et les renseignements établissant, documents à l'appui, que les conditions prévues au paragraphe (1) du présent article sont réunies.

Décision du ministre

(4) Le ministre fait droit à la demande d'exemption dans les trente jours suivant la date de réception de la demande s'il est convaincu que les conditions visées au paragraphe (1) sont réunies.

Durée de l'exemption

(5) L'exemption est valide à compter de la date du début de la situation d'urgence jusqu'à la première des dates ci-après à survenir :

a) la date à laquelle tombe le quatre-vingt-dixième jour suivant cette date;

b) la date fixée par le ministre;

c) la date à laquelle la circonstance visée à l'alinéa (2)a) cesse d'entraîner une interruption ou un risque important d'interruption de l'approvisionnement en électricité dans la province où le groupe est situé;

d) la date à laquelle la mesure visée à l'alinéa (2)b) cesse de s'appliquer.

Demande de prolongation de l'exemption

20 (1) Si les conditions prévues au paragraphe 19(1) persistent au-delà de la durée de l'exemption accordée au titre du paragraphe 19(4), la personne responsable peut, tant que l'exemption est valide, présenter au ministre une demande de prolongation de celle-ci.

Contenu de la demande

(2) La demande de prolongation comporte :

a) le cas échéant, le numéro d'enregistrement que lui a attribué le ministre;

b) la date du début de la situation d'urgence;

c) les renseignements établissant, documents à l'appui, que les conditions prévues au paragraphe 19(1) persistent au-delà de la durée de l'exemption accordée.

Décision du ministre

(3) Le ministre fait droit à la demande de prolongation dans les quinze jours suivant la date de réception de la demande s'il est convaincu que la condition prévue à l'alinéa (2)c) a été établie.

Duration of extension

(4) The extension ceases to have effect on the earliest of

(a) the 90th day after the day on which the application for the extension was made,

(b) the day specified by the Minister, and

(c) the day referred to in paragraph 19(5)(c).

Sampling and Missing Data

Sampling

21 (1) The determination of the value of the elements referred to in a formula in section 14 must be based on fuel samples taken in accordance with this section.

Carbon content provided by the supplier

(2) If the supplier of the fuel has provided the carbon content of the fuel and that carbon content has been determined in accordance with subsection 14(2), using the applicable sampling period and minimum sampling frequency set out in subsection (3), the responsible person may use that information rather than taking samples in accordance with subsection (3).

Frequency

(3) Each fuel sample must be taken at a time and location in the fuel handling system of the facility that provides the following representative samples of the fuel combusted at the applicable minimum frequency:

(a) for natural gas, during each sampling period consisting of each year that the unit generates electricity or produces useful thermal energy, two samples taken that year, with each of those samples being taken at least four months after any previous sample has been taken, in accordance with whichever of the following standard that applies:

(i) ASTM D4057-12, entitled *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*,

(ii) ASTM D4177-16e1, entitled *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*,

(iii) ASTM D5287-08(2015), entitled *Standard Practice for Automatic Sampling of Gaseous Fuels*, and

(iv) ASTM F307-13, entitled *Standard Practice for Sampling Pressurized Gas for Gas Analysis*;

Durée de la prolongation

(4) La prolongation est valide jusqu'à la première des dates ci-après à survenir :

a) la date tombant le quatre-vingt-dixième jour suivant la date à laquelle la demande de prolongation a été présentée;

b) la date fixée par le ministre;

c) la date visée à l'alinéa 19(5)c).

Échantillonnage et données manquantes

Échantillonnage

21 (1) La valeur des variables des formules visées à l'article 14 est déterminée à partir d'échantillons de combustible prélevés conformément au présent article.

Contenu en carbone fourni par le fournisseur

(2) Si le fournisseur du combustible lui a fourni le contenu en carbone du combustible et que ce contenu en carbone a été déterminé conformément au paragraphe 14(2) en utilisant la période d'échantillonnage et la fréquence d'échantillonnage minimale applicables précisées au paragraphe (3), la personne responsable peut utiliser cette information au lieu de prélever des échantillons conformément à ce paragraphe.

Fréquence

(3) Chaque prélèvement est effectué à un moment et à un point du système de manutention du combustible de l'installation permettant de fournir les échantillons représentatifs ci-après du combustible brûlé, à la fréquence minimale applicable :

a) s'agissant de gaz naturel, durant chaque période d'échantillonnage correspondant à chaque année au cours de laquelle le groupe produit de l'électricité ou de l'énergie thermique utile, deux échantillons prélevés au cours de cette année, à au moins quatre mois d'intervalle, selon la norme applicable suivante :

(i) la norme ASTM D4057-12 intitulée *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*,

(ii) la norme ASTM D4177-16e1 intitulée *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*,

(iii) la norme ASTM D5287-08(2015) intitulée *Standard Practice for Automatic Sampling of Gaseous Fuels*,

(iv) la norme ASTM F307-13 intitulée *Standard Practice for Sampling Pressurized Gas For Gas Analysis*;

(b) for refinery gas, during each sampling period consisting of each day that the unit generates electricity or produces useful thermal energy, one sample per day that is taken at least six hours after any previous sample has been taken, in accordance with any applicable standard referred to in paragraph (a);

(c) for a type of liquid fuel or of a gaseous fuel other than refinery gas and natural gas, during each sampling period consisting of each month that the unit generates electricity or produces useful thermal energy, one sample per month that is taken at least two weeks after any previous sample has been taken, in accordance with any of the standards referred to in paragraph (a); and

(d) for a solid fuel, one composite sample per month that consists of sub-samples, each having the same mass, that are taken from the fuel that is fed for combustion during each week that begins in that month and during which the unit generates electricity or produces useful thermal energy, and after all fuel treatment operations have been carried out but before any mixing of the fuel from which the sub-sample is taken with other fuels, and at least 72 hours after any previous sub-sample has been taken.

Additional samples

(4) Despite subsection (3), if the responsible person takes more samples or composite samples, as the case may be, than the minimum required and a determination is made on the carbon content of any of those samples or composite samples, using a method set out for CC_i in subsection 14(2) for that fuel type, the results of those determinations must be included in the determination of CC_A set out in subsection 14(2).

Missing data

22 (1) If, for any reason beyond the responsible person's control, any element of any formula in the Regulations cannot be determined because data required to determine it is missing for a given period in a calendar year, replacement data for that given period must be used to determine that value.

Replacement data — CEMS

(2) If a CEMS is used to determine the value of an element of a formula set out in sections 9 to 11 but data is missing for a given period, the replacement data must be obtained in accordance with Section 3.5.2 of the Reference Method.

Replacement data — non-CEMS

(3) If data, other than data referred to in subsection (2), required to determine the value of any element of a formula in these Regulations is missing for a given period, the replacement data is to be the average of the available

b) s'agissant de gaz de raffinerie, durant chaque période d'échantillonnage correspondant à chaque journée au cours de laquelle le groupe produit de l'électricité ou de l'énergie thermique utile, un échantillon de gaz de raffinerie par journée, prélevé au moins six heures après l'échantillon précédant, conformément à l'une des normes applicables visées à l'alinéa a);

c) s'agissant d'un type de combustible liquide ou gazeux autre que du gaz de raffinerie ou du gaz naturel, durant chaque période d'échantillonnage correspondant à chaque mois au cours duquel le groupe produit de l'électricité ou de l'énergie thermique utile, un échantillon de combustible par mois, prélevé à au moins deux semaines d'intervalle, conformément à l'une des normes visées à l'alinéa a);

d) s'agissant d'un combustible solide, un échantillon composite par mois établi à partir de sous-échantillons de même masse du combustible ayant servi à la combustion prélevés chaque semaine au cours de laquelle le groupe produit de l'électricité ou de l'énergie thermique utile et qui commence au cours du mois, après tout traitement du combustible, mais avant que celui-ci ne soit mélangé à d'autres combustibles, et à au moins soixante-douze heures d'intervalle.

Échantillons additionnels

(4) Malgré le paragraphe (3), si le nombre d'échantillons ou d'échantillons composites, selon le cas, prélevés dépasse le nombre minimal requis et qu'une détermination du contenu en carbone de ceux-ci est faite conformément à la formule prévue au paragraphe 14(2) pour déterminer la valeur de la variable CC_i pour le type de combustible en cause, la personne responsable tient compte des résultats de cette détermination pour déterminer la valeur de la variable CC_m prévue au paragraphe 14(2).

Données manquantes

22 (1) Si, pour une raison indépendante de la volonté de la personne responsable, il manque, pour une période donnée d'une année civile, des données pour déterminer une variable des formules prévues au présent règlement, des données de remplacement, établies pour cette période, sont utilisées à cette fin.

Variable déterminée à l'aide d'un SMECE

(2) Si un SMECE est utilisé pour déterminer une variable des formules prévues aux articles 9 à 11 et qu'il manque une donnée pour une période donnée, la donnée de remplacement est obtenue conformément à la section 3.5.2 de la méthode de référence.

Variable non déterminée à l'aide d'un SMECE

(3) Si des données, autres que celles visées au paragraphe (2), requises pour déterminer la valeur d'une variable d'une formule prévu au présent règlement sont manquantes pour une période donnée, la donnée de remplacement est data for that element during the equivalent period prior to and, if the data is available, subsequent to that given period. However, if no data is available for that element for the equivalent period prior to that given period, the replacement data to be used is the value determined for that element during the equivalent period subsequent to the given period.

la moyenne des données disponibles pour cette variable pour la période équivalente précédant la période en cause et, si les données sont disponibles, pour la période équivalente qui la suit. Toutefois, si aucune donnée n'est disponible pour cette variable pour la période équivalente précédant la période en cause, la donnée de remplacement est la valeur établie pour la variable pour la période équivalente qui suit cette période.

Replacement data — maximum days

(4) During a calendar year, there may be more than one given period, but replacement data may be used for a maximum of 28 days during the calendar year, distributed among any or all of those periods.

Données de remplacement — durée maximale

(4) Si une donnée n'est pas disponible au cours d'une ou plusieurs périodes données au cours de l'année civile en cause, une donnée de remplacement ne peut être fournie que pour un maximum de vingt-huit jours de cette année civile, répartis sur une ou plusieurs des périodes en cause.

Accuracy of Data

Measuring devices — installation, maintenance and calibration

23 (1) A responsible person must install, maintain and calibrate a measuring device, other than a continuous emission monitoring system and a measuring device that is subject to the *Electricity and Gas Inspection Act*, that is used for the purposes of these Regulations in accordance with the manufacturer's instructions or any applicable generally recognized national or international industry standard.

Frequency of calibration

(2) The responsible person must calibrate each of the measuring devices at the following frequencies:

(a) at least once in every calendar year but at least five months after a previous calibration; or

(b) the minimum frequency recommended by the manufacturer.

Accuracy of measurements

(3) The responsible person must use measuring devices that enable measurements to be made with a degree of accuracy of ±5%.

Exactitude des données

Instruments de mesure — mise en place, entretien et étalonnage

23 (1) La personne responsable met en place, entretient et étalonne les instruments de mesure — autres que le système de mesure et d'enregistrement en continu des émissions et que tout instrument de mesure assujetti à la *Loi sur l'inspection de l'électricité et du gaz* — utilisés pour l'application du présent règlement conformément aux instructions du fabricant ou à une norme applicable généralement reconnue par l'industrie à l'échelle nationale ou internationale.

Fréquence de l'étalonnage

(2) La personne responsable étalonne chacun des instruments de mesure à l'une ou l'autre des fréquences suivantes :

a) au moins une fois par année civile et à au moins cinq mois d'intervalle;

b) la fréquence minimale recommandée par le fabricant.

Exactitude des mesures

(3) La personne responsable utilise des instruments de mesure qui permettent la prise des mesures selon un degré d'exactitude de ± 5 %.

Reporting

Annual reports

24 (1) Subject to subsection (3), beginning in the calendar year during which section 6 applies to the responsible person, that responsible person must submit an annual report with respect to the unit containing the information referred to in Schedule 2 for each calendar year the unit meets the criteria set out in section 3 of these Regulations.

Rapports

Rapports annuels

24 (1) Sous réserve du paragraphe (3), la personne responsable est tenue, à compter de la première année au cours de laquelle l'article 6 s'applique à elle, de transmettre au ministre un rapport annuel à l'égard du groupe comportant les renseignements énumérés à l'annexe 2 à l'égard de chaque année civile au cours de laquelle le groupe remplit les conditions prévues à l'article 3 du présent règlement.

June 1

(2) The responsible person must submit the annual report on or before June 1 of the calendar year that follows the calendar year that is the subject of the report.

Permanent cessation

(3) If a unit permanently ceases to generate electricity in a calendar year, the responsible person for the unit must submit to the Minister a notice, in writing, not later than 60 days after the day on which the unit ceases generating electricity, containing the information set out in Schedule 5. An annual report is not required to be submitted in respect of the calendar years following the calendar year in which the unit ceases generating electricity.

Change of information

25 If there is a change to any information submitted to the Minister in the registration report, the responsible person must notify the Minister of the change and provide the new information, in writing, not later than 60 days after the day on which the change is made.

Correcting error

26 A responsible person must, without delay, notify the Minister, in writing, of any error in the information in a report submitted in accordance with these Regulations and provide the corrected information.

Signature and submission — electronic

27 (1) A report or notice that is required, or an application that is made, under these Regulations must be submitted electronically in the form specified by the Minister and must bear the electronic signature of the responsible person or their authorized official.

Paper report, notice and application

(2) If the Minister has not specified an electronic form or if the person is unable to submit the report, notice or application electronically in accordance with subsection (1) because of circumstances beyond the person's control, the report, notice or application must be sent on paper, in the form specified by the Minister, if applicable, and be signed by the responsible person or their authorized official.

Records

Record

28 (1) A responsible person must make a record containing the following documents and information:

> **(a)** any notice, declaration, application, attestation, report or information submitted to the Minister under these Regulations, along with supporting documents;
>
> **(b)** measurements and calculations used to determine the value of an element of any formula set out in sections 7, 8, 10, 11 and 13 to 18, as applicable, along with

1er juin

(2) La personne responsable transmet le rapport annuel au plus tard le 1er juin de l'année civile qui suit l'année civile faisant l'objet du rapport.

Cessation définitive

(3) Si le groupe cesse définitivement de produire de l'électricité au cours de l'année civile, la personne responsable transmet au ministre un avis écrit contenant les renseignements visés à l'annexe 5 au plus tard soixante jours après la date à laquelle le groupe cesse sa production. Il n'est pas nécessaire de transmettre un rapport annuel à l'égard des années civiles suivant celle au cours de laquelle le groupe cesse sa production.

Modification aux renseignements

25 La personne responsable avise par écrit le ministre de toute modification apportée aux renseignements qui lui ont été fournis dans le rapport d'enregistrement et lui fournit les renseignements corrigés dans les soixante jours suivant le jour de la modification.

Correction d'erreur

26 La personne responsable, sans délai, avise par écrit le ministre de toute erreur dans les renseignements fournis dans un rapport transmis en application du présent règlement et lui fournit les renseignements corrigés.

Transmission et signature électroniques

27 (1) Les rapports et avis requis par le présent règlement et les demandes faites aux termes de celui-ci sont transmis électroniquement en la forme précisée par le ministre et portent la signature électronique de la personne responsable ou son agent autorisé.

Rapports, avis et demandes sur support papier

(2) Si le ministre n'a pas précisé de forme électronique ou si, en raison de circonstances indépendantes de sa volonté, la personne qui transmet le rapport ou l'avis ou qui présente la demande n'est pas en mesure de le faire conformément au paragraphe (1), elle transmet le rapport ou l'avis ou présente la demande sur support papier, signé par la personne responsable ou son agent autorisé, en la forme précisée par le ministre, le cas échéant.

Dossier

Contenu du dossier

28 (1) La personne responsable constitue un dossier contenant les renseignements et documents suivants :

> **a)** tout avis, attestation, déclaration, demande, rapport ou renseignement transmis au ministre en application du présent règlement, y compris les documents à l'appui;
>
> **b)** le relevé des mesures et la description des calculs effectués pour déterminer la valeur d'une variable des

an indication of the standards or methods that were used to determine the value of the elements used in those formulas, along with supporting documents;

(c) an indication of the standards or methods referred to in the description of CC_i in subsection 14(1) for a sample of gaseous fuel, including a statement that indicates that a direct measuring device was used to determine that value;

(d) information demonstrating that an electricity meter referred to in section 18 complies with the requirements of the *Electricity and Gas Inspection Act* and the *Electricity and Gas Inspection Regulations*, including a certificate referred to in section 14 of that Act;

(e) the manufacturer's instructions for any measuring device used to determine any value or quantity in any section of these Regulations;

(f) information demonstrating that the requirements set out in section 23 are met;

(g) supporting documents that confirm the CEMS certification under subsection 12(2);

(h) any document, record or information referred to in Section 8 of the Reference Method, for each calendar year during which a responsible person used a CEMS;

(i) the results of the analysis of every sample taken in accordance with section 21, as well as the date that each sample was taken and an indication of the standards that were used to take representative samples of the fuel;

(j) if the supplier of hydrogen or steam has provided the quantity of E_k or P_k under subsection 17(2), the information provided by the supplier;

(k) if the supplier of fuel has provided the carbon content of that fuel under subsection 21(2), the information provided by the supplier;

(l) information demonstrating electricity generation capacity submitted in the registration report and each annual report; and

(m) if replacement data was used under section 22, information with respect to the reason replacement data was required, along with the replacement data that was used.

formules visées aux articles 7, 8, 10, 11 et 13 à 18, selon le cas, ainsi que la mention des normes ou des méthodes utilisées pour déterminer la valeur des variables de ces formules et les documents à l'appui;

c) la mention des normes ou des méthodes visées dans la description de la variable CC_i au paragraphe 14(2) pour un échantillon gazeux qui ont été utilisées et l'indication qu'un instrument de mesure directe a été utilisé à cette fin;

d) les renseignements établissant que les compteurs électriques visés à l'article 18 répondent aux exigences de la *Loi sur l'inspection de l'électricité et du gaz* et du *Règlement sur l'inspection de l'électricité et du gaz*, y compris celle relative au certificat prévue à l'article 14 de cette loi;

e) les instructions du fabricant relatives à tout instrument de mesure utilisé pour déterminer toute valeur ou quantité aux termes du présent règlement;

f) les renseignements établissant que les exigences prévues à l'article 23 sont respectées;

g) les documents à l'appui qui confirment l'homologation du SMECE aux termes du paragraphe 12(2);

h) à l'égard de chaque année civile au cours de laquelle la personne responsable utilise un SMECE, les renseignements et les documents visés à la section 8 de la méthode de référence;

i) le résultat d'analyse de chaque échantillon prélevé conformément à l'article 21, ainsi que la date du prélèvement de chaque échantillon et la mention des normes qui ont été utilisées pour prendre les échantillons représentatifs du combustible;

j) si les valeurs de E_k et de P_k sont obtenues du fournisseur d'hydrogène ou de vapeur au titre du paragraphe 17(2), les renseignements obtenus du fournisseur;

k) si le contenu en carbone du combustible est obtenu du fournisseur du combustible au titre du paragraphe 21(2), les renseignements obtenus du fournisseur;

l) les renseignements établissant la capacité de production d'électricité indiquée dans le rapport d'enregistrement et dans chaque rapport annuel;

m) si des données de remplacement ont été utilisées en application de l'article 22, les renseignements établissant la raison pour laquelle les données étaient nécessaires ainsi que les données elles-mêmes.

Time limit

(2) The records must be made as soon as feasible but not later than 30 days after the day on which the information and documents to be included in it become available.

Retention of records, reports and notices

29 (1) A responsible person that is required under these Regulations to make a record or send a report or notice must keep the record or a copy of the report or notice, along with the supporting documents

(a) until the responsible person has submitted a notice of permanent cessation under subsection 24(3), with respect to documentation set out in Schedule 1; or

(b) for a period of seven years after the later of when the record is made or a report or notice is submitted to the Minister.

Location of records

(2) A record or copy must be kept at the responsible person's principal place of business in Canada or at any other place in Canada where it can be inspected. If the record or copy is kept at any of those other places, the responsible person must provide the Minister with a civic address of that other place.

Relocation of records

(3) If the records are moved, the responsible person must notify the Minister, in writing, of the civic address in Canada of the new location within 30 days after the day of the move.

Language of Documents

Language of documents

30 All documents required by these Regulations must be in English or French, or be accompanied by a translation in English or French and an affidavit of the translator attesting to the accuracy of the translation.

Délai

(2) Le dossier est constitué dès que possible, mais au plus tard trente jours après la date à laquelle les renseignements et documents devant y être consignés deviennent accessibles.

Conservation des dossiers, rapports et avis

29 (1) La personne responsable tenue, en application du présent règlement, de constituer un dossier ou de transmettre un rapport ou un avis conserve le dossier ou une copie du rapport ou de l'avis, ainsi que les documents à l'appui :

a) dans le cas des documents concernant les éléments énumérés à l'annexe 1, jusqu'à ce que la personne responsable transmette un avis de cessation définitive de production conformément au paragraphe 24(3);

b) dans les autres cas, pendant au moins sept ans après avoir constitué le dossier ou avoir transmis le rapport ou l'avis au ministre.

Lieu de conservation des dossiers

(2) Le dossier ou la copie de celui-ci sont conservés à l'établissement principal de la personne responsable au Canada ou en tout autre lieu au Canada où ils peuvent être examinés. Dans ce dernier cas, la personne responsable informe le ministre de l'adresse municipale du lieu.

Changement de lieu de conservation

(3) Si le lieu de conservation du dossier change, la personne responsable avise le ministre par écrit de l'adresse municipale du nouveau lieu dans les trente jours suivant la date du changement.

Langue des documents

Langue des documents

30 Les documents exigés par le présent règlement sont rédigés en français ou en anglais ou sont accompagnés d'une traduction française ou anglaise et d'une déclaration sous serment du traducteur qui en atteste la fidélité.

Consequential Amendment to the Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act, 1999)

31 The schedule to the *Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act, 1999)*[1] is amended by adding the following in numerical order:

Item	Column 1 Regulations	Column 2 Provisions
42	*Clean Electricity Regulations*	(a) subsection 6(1) (b) subsection 6(2) (c) subsection 6(3)

Repeals

32 The *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*[2] is repealed.

33 The *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*[3] is repealed.

Coming into Force

January 1, 2025

34 (1) These Regulations, except sections 32 and 33, come into force on January 1, 2025.

January 1, 2035

(2) Section 32 comes into force on January 1, 2035.

January 1, 2045

(3) Section 33 comes into force on January 1, 2045.

1 SOR/2012-134
2 SOR/2012-167
3 SOR/2018-261

Modification connexe au Règlement sur les dispositions réglementaires désignées aux fins de contrôle d'application — Loi canadienne sur la protection de l'environnement (1999)

31 L'annexe du *Règlement sur les dispositions réglementaires désignées aux fins de contrôle d'application — Loi canadienne sur la protection de l'environnement (1999)*[1] est modifiée par adjonction, selon l'ordre numérique, de ce qui suit :

Article	Colonne 1 Règlement	Colonne 2 Dispositions
42	*Règlement sur l'électricité propre*	a) paragraphe 6(1) b) paragraphe 6(2) c) paragraphe 6(3)

Abrogations

32 Le *Règlement sur la réduction des émissions de dioxyde de carbone — secteur de l'électricité thermique au charbon*[2] est abrogé.

33 Le *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*[3] est abrogé.

Entrée en vigueur

1er janvier 2025

34 (1) Le présent règlement, sauf les articles 32 et 33, entre en vigueur le 1er janvier 2025.

1er janvier 2035

(2) L'article 32 entre en vigueur le 1er janvier 2035.

1er janvier 2045

(3) L'article 33 entre en vigueur le 1er janvier 2045.

1 DORS/2012-134
2 DORS/2012-167
3 DORS/2018-261

SCHEDULE 1

(Subsection 4(1), paragraph 4(2)(a), subsection 19(3), and paragraph 29(1)(a))

Registration Report — Information Required

1 The following information respecting the responsible person:

(a) an indication of whether they are the owner or operator of the unit and their name and civic address;

(b) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number of their authorized official; and

(c) the name, title, civic and postal addresses, telephone number and, if any, email address and fax number of a contact person, if different from the authorized official.

2 The following information respecting the unit:

(a) for each responsible person for the unit, other than the responsible person referred to in paragraph 1(a), if any,

(i) their name and civic address,

(ii) an indication of whether they are an owner or operator, and

(iii) in the case of an owner, their percentage of ownership interest;

(b) its name and civic address, if any;

(c) if applicable, its National Pollutant Release Inventory identification number assigned by the Minister for the purpose of section 48 of the *Canadian Environmental Protection Act, 1999*;

(d) the year, determined in accordance with section 6(4) of these Regulations, in which it must meet the intensity limit;

(e) its commissioning date;

(f) the date each piece of equipment that comprises it started operating;

(g) the date on which the carbon capture and storage system equipment started operating, if applicable;

(h) its electricity generation capacity;

(i) its registration number, if any, assigned by the Minister under subsection 4(2) of the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*;

ANNEXE 1

(paragraphe 4(1), alinéa 4(2)a), paragraphe 19(3) et alinéa 29(1)a))

Rapport d'enregistrement — renseignements à fournir

1 Renseignements sur la personne responsable :

a) une mention portant qu'elle est le propriétaire ou l'exploitant du groupe, ainsi que ses nom et adresse municipale;

b) les nom, titre, adresses municipale et postale, numéro de téléphone et, le cas échéant, numéro de télécopieur et adresse électronique de son agent autorisé;

c) les nom, titre, adresses municipale et postale, numéro de téléphone et, le cas échéant, numéro de télécopieur et adresse électronique d'une personne-ressource, si celle-ci n'est pas l'agent autorisé.

2 Renseignements sur le groupe :

a) le cas échéant, à l'égard de chaque personne responsable du groupe autre que celle qui est mentionnée à l'alinéa 1a) :

(i) ses nom et adresse municipale,

(ii) une mention portant qu'elle est le propriétaire ou l'exploitant,

(iii) dans le cas où elle est le propriétaire, le pourcentage du titre de participation dans ce groupe;

b) ses nom et adresse municipale, le cas échéant;

c) le cas échéant, le numéro d'identification que lui a attribué le ministre pour les besoins de l'inventaire national des rejets polluants établi en application de l'article 48 de la *Loi canadienne sur la protection de l'environnement (1999)*;

d) l'année déterminée en application du paragraphe 6(4) du présent règlement au cours de laquelle il est tenu de respecter la limite d'intensité d'émissions;

e) la date de sa mise en service;

f) pour chaque pièce d'équipement du groupe, la date à laquelle elle a commencé à fonctionner;

g) la date à laquelle l'équipement du système de captage et de stockage de carbone a commencé à fonctionner, s'il y a lieu;

h) sa capacité de production d'électricité;

i) le cas échéant, le numéro d'enregistrement que lui a attribué le ministre en vertu du paragraphe 4(2) du

(j) the unit's registration number, if any, assigned by the Minister under subsection 21(4) of the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*;

(k) a process diagram of the unit that indicates, if applicable,

(i) major equipment, including boilers, combustion engines, duct burners and other combustion devices, heat recovery systems, steam turbines, generators and emission control devices and carbon capture and storage system equipment,

(ii) how the equipment referred to in subparagraph (i) is physically connected and operates together,

(iii) the unit boundaries used to identify the unit,

(iv) the electric flows crossing the unit boundaries, and

(v) if applicable, the heat streams crossing the unit boundaries and their average temperature, pressure and hourly mass flow rate; and

(l) if the unit contains a combustion engine, boiler or steam turbine that was previously contained in another unit registered under these Regulations,

(i) the registration number of the previous unit,

(ii) the electricity generation capacity of the combustion engine, that is part of the combustion equipment, or steam turbine, as applicable, and

(iii) the date on which the combustion engine, boiler or steam turbine started operating in the unit that is the subject of the report.

Règlement sur la réduction des émissions de dioxyde de carbone provenant de la production d'électricité au charbon;

j) le cas échéant, le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 21(4) du *Règlement limitant les émissions de dioxyde de carbone provenant de la production d'électricité thermique au gaz naturel*;

k) un schéma de procédé illustrant, pour le groupe, s'il y a lieu :

(i) l'équipement principal, notamment les chaudières, moteurs à combustion, brûleurs de conduit ou autres dispositifs de combustion, systèmes de récupération de la chaleur, turbines à vapeur, générateurs ou dispositifs de contrôle des émissions,

(ii) comment tout équipement visé au sous-alinéa (i) est physiquement raccordé et fonctionne ensemble,

(iii) le périmètre utilisé pour identifier le groupe,

(iv) les flux électriques qui franchissent le périmètre du groupe,

(v) le cas échéant, les flux calorifiques qui franchissent le périmètre du groupe et leur température, leur pression et leur débit massique horaire moyens;

l) s'il comprend un moteur à combustion, une chaudière ou une turbine à vapeur qui étaient compris dans un groupe qui était déjà enregistré aux termes du présent règlement :

(i) le numéro d'enregistrement du groupe déjà enregistré,

(ii) la capacité de production d'électricité de tout moteur à combustion compris dans l'équipement de combustion, ou de toute turbine à vapeur, selon le cas,

(iii) la date à laquelle le moteur à combustion, la chaudière ou la turbine à vapeur du groupe qui fait l'objet du rapport a commencé à fonctionner.

SCHEDULE 2

(Subsections 5(4) and 24(1))

Annual Report — Information Required

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

ANNEXE 2

(paragraphes 5(4) et 24(1))

Rapport annuel — renseignements à fournir

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 The following information for the calendar year:

(a) the number of hours during which the unit produced electricity; and

(b) with respect to a unit for which the Minister has issued an exemption under section 19 or an extension under section 20 of these Regulations,

(i) the period for which the exemption or extension was issued,

(ii) the number of hours during the period referred to in subparagraph (i) during which the unit operated.

3 The following information respecting the emission intensity referred to in section 7 of these Regulations:

(a) the emission intensity for the unit, expressed in tonnes of CO_2 per GWh;

(b) in respect of the quantity of CO_2 emissions from the combustion of fuels in the unit (E_u), if that quantity is

(i) determined in accordance with section 9, 10 or 11 of these Regulations, the quantity determined in accordance with the applicable section, expressed in tonnes, and

(ii) determined in accordance with section 13 of these Regulations,

(A) the quantity determined in accordance with that section, expressed in tonnes,

(B) the quantity of CO_2 emissions attributable to the combustion of a fossil fuel for each fossil fuel type (E_i), determined in accordance with section 14 of these Regulations, expressed in tonnes, and

(C) the quantity of CO_2 emissions that is released from the sorbent (E_s), for each fossil fuel type, expressed in tonnes;

(c) for each type of fuel combusted in the unit

(i) the type, and if that type is biomass, an explanation of how that it meets the definition *biomass* in subsection 2(1) of these Regulations, and

(ii) the quantity of fuel combusted;

2 Renseignements à l'égard des éléments ci-après pour l'année civile :

a) le nombre d'heures pendant lesquelles le groupe a produit de l'électricité;

b) dans le cas d'un groupe visé par une exemption accordée en application de l'article 19 du présent règlement ou prolongée en application de l'article 20 de celui-ci :

(i) la période à l'égard de laquelle l'exemption a été accordée ou prolongée,

(ii) le nombre d'heures au cours de la période visée au sous-alinéa (i) durant lesquelles le groupe a fonctionné.

3 Renseignements sur l'intensité des émissions visée à l'article 7 du présent règlement :

a) l'intensité des émissions provenant du groupe, exprimée en tonnes de CO_2 par GWh;

b) à l'égard de la quantité d'émissions de CO_2 provenant de la combustion de combustibles par le groupe (E_g) :

(i) si elle est déterminée conformément aux articles 9, 10 ou 11 du présent règlement, la quantité déterminée conformément à l'article applicable, exprimée en tonnes,

(ii) si elle est déterminée conformément à l'article 13 du présent règlement :

(A) la quantité déterminée conformément à cet article, exprimée en tonnes,

(B) la quantité d'émissions de CO_2 qui est attribuable à la combustion de combustibles fossiles à l'égard de chaque type de combustible brûlé (E_i), déterminée conformément à l'article 14 du présent règlement et exprimée en tonnes,

(C) la quantité d'émissions de CO_2 qui provient du sorbant utilisé (E_s) à l'égard de chaque type de combustible brûlé, exprimée en tonnes;

c) à l'égard de chaque type de combustible brûlé par le groupe :

(i) le type et, s'il s'agit de biomasse, une mention indiquant en quoi ce type est de la *biomasse* au sens du paragraphe 2(1) du présent règlement,

(ii) la quantité brûlée;

(d) in respect of the quantity of electricity generated by the unit,

(i) that quantity determined in accordance with subsection 18(1) of these Regulations, expressed in GWh, and

(ii) the values determined for G_{gross} and G_{ec} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh; and

(e) the weighted average of the carbon content of the fuel (CC_A), determined in accordance with subsection 14(2) of these Regulations, for each fuel combusted, along with an indication of which ASTM standard or method, including using a direct measuring device, was used for each calculation.

4 The following information with respect to the unit:

(a) the values determined for E_{th}, E_{ccs}, E_{ext} and E_{ec}, in the formula set out in section 8 of these Regulations, expressed in tonnes;

(b) the values determined for H_{pnet}, h_{out_i}, M_{out_i}, h_{in_j} and M_{in_j} used to determine E_{th} in accordance with section 15 of these Regulations, expressed in GJ, tonnes, or GJ/tonne, as applicable;

(c) the values determined for E_{cap} and E_{in}, used to determine E_{ccs} in accordance with section 16 of these Regulations, expressed in tonnes;

(d) the values determined for E_k, P_k and Q_k, used to determine E_{ext} in accordance with section 17 of these Regulations, expressed in tonnes or GJ, as applicable;

(e) the values referred to in section 3 of this Schedule for any calculation done in accordance with subsection 8(2) of these Regulations;

(f) the result of the formula in subsection 18(1) of these Regulations, expressed in GWh;

(g) the value determined for G_{gross} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh;

(h) the value determined for G_{ec} in the formula set out in subsection 18(1) of these Regulations, expressed in GWh; and

(i) its net exports, expressed in GWh, during the previous calendar year.

5 With respect to a unit for which the Minister has issued an exemption under section 19 or an extension under

d) à l'égard de la quantité d'électricité produite par le groupe :

(i) la quantité déterminée conformément au paragraphe 18(1) du présent règlement, exprimée en GWh,

(ii) la valeur déterminée pour les variables G_{brute} et G_{su} dans la formule prévue au paragraphe 18(1) du présent règlement, exprimée en GWh;

e) la moyenne pondérée du contenu en carbone du combustible (CC_M) dans la formule prévue au paragraphe 14(2) du présent règlement à l'égard de chaque type de combustible brûlé, ainsi que la mention des normes ASTM, méthodes et instruments de mesure qui ont été utilisés pour chaque calcul.

4 Pour tous les groupes :

a) les valeurs, exprimées en tonnes, déterminées pour les variables E_{th}, E_{csc}, E_{ext} et E_{su} utilisées dans la formule visée à l'article 8 du présent règlement;

b) les valeurs, exprimées en GJ, GJ/tonnes ou tonnes selon le cas, déterminées pour les variables H_{pnette}, h_{sort_i}, M_{sort_i}, h_{intr_j} et M_{intr_j} utilisées dans la formule visée à l'article 15 du présent règlement pour déterminer la variable E_{th};

c) les valeurs, exprimées en tonnes, déterminées pour les variables E_{cap} et E_{in} utilisées dans la formule visée à l'article 16 du présent règlement pour déterminer la variable E_{csc};

d) les valeurs, exprimées en tonnes ou GJ selon le cas, déterminées pour les variables E_k P_k et Q_k utilisées dans la formule visée à l'article 17 du présent règlement pour déterminer la variable E_{ext};

e) les valeurs visées à l'article 3 de la présente annexe pour chaque calcul effectué au paragraphe 8(2) du présent règlement;

f) le résultat de la formule prévue au paragraphe 18(1) du présent règlement, exprimée en GWh;

g) la valeur, exprimée en GWh, déterminée pour la variable G_{brute} dans la formule prévue au paragraphe 18(1) du présent règlement;

h) la valeur, exprimée en GWh, déterminée pour la variable G_{su} dans la formule prévue au paragraphe 18(1) du présent règlement;

i) le solde exportateur au cours de l'année civile précédente.

5 Pour tout groupe visé par une exemption accordée en application de l'article 19 du présent règlement ou section 20 of these Regulations, the duration of the emergency circumstance, including the date on which the circumstance arose and the date on which it ceased.

6 With respect to a unit referred to in subsection 6(2) of these Regulations,

(a) the year in which the carbon capture and storage system started operating and documents establishing that the captured CO_2 was captured, transported and stored in accordance with the requirements of subsection 8(4) of these Regulations, and

(b) documentation demonstrating that the unit operated at or below 30 tonnes/GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in the calendar year for which the annual report is submitted.

7 With respect to a unit referred to in subsection 6(3) of these Regulations, a statement that an exemption referred to in that subsection is being used for the calendar year.

8 If applicable, a copy of the auditor's report referred to in subsection 12(3) of these Regulations.

9 The following information respecting the replacement data referred to in section 22 of these Regulations that was used for a given period during the calendar year, if applicable:

(a) the reason why data required to determine the value of an element of a formula referred to in these Regulations was not obtained and how that reason was beyond the responsible person's control;

(b) the element of the formula for which data was not obtained and the date of the day on which the data was not obtained and, if that data was not obtained for a period of several days, the dates of the days on which the period begins and ends; and

(c) the value determined for the element referred to in paragraph (b) using replacement data, along with details of that determination, including

(i) the data used to make that determination for each period of one or more days,

(ii) the method used to obtain that replacement data, and

(iii) in the case of a determination of the value of an element referred to in subsection 22(3) of these Regulations, a justification for the given period being used as the basis of that determination.

prolongée en application de l'article 20 de celui-ci, la durée de la situation d'urgence, incluant la date à laquelle la situation a débuté et celle à laquelle elle a pris fin.

6 Renseignement à l'égard d'un groupe visé au paragraphe 6(2) du présent règlement :

a) l'année au cours de laquelle le système de captage et de stockage de carbone a commencé à opérer et les renseignements établissant, documents à l'appui, que les émissions de CO_2 ont été captées, transportées et stockées conformément au paragraphe 8(4) du présent règlement;

b) les documents établissant que le groupe a fonctionné à une intensité inférieure ou égale à 30 tonnes/GWh pendant deux périodes d'au moins douze heures consécutives, ces périodes étant séparées d'au moins quatre mois au cours de l'année civile à l'égard de laquelle le rapport annuel est soumis.

7 S'agissant d'un groupe visé au paragraphe 6(3) du présent règlement, une mention indiquant que l'exemption prévue à ce paragraphe est utilisée pour l'année civile.

8 Le cas échéant, une copie du rapport du vérificateur visé au paragraphe 12(3) du présent règlement.

9 Renseignements sur les données de remplacement utilisées pour une période donnée au cours de l'année civile en application de l'article 22, le cas échéant :

a) la raison pour laquelle les données nécessaires pour déterminer une variable des formules prévues au présent règlement n'ont pas été obtenues et une explication établissant en quoi cette raison est indépendante de la volonté de la personne responsable;

b) la variable de la formule pour laquelle les données n'ont pas été obtenues et la date du jour en cause et, s'il s'agit d'une période de plusieurs jours, la date du début de cette période et la date à laquelle elle a pris fin;

c) la valeur de la variable visée à l'alinéa b) déterminée à l'aide de données de remplacement, et des précisions sur la façon dont elle a été déterminée, notamment :

(i) les données utilisées au cours de toute période d'un ou de plusieurs jours pour faire cette détermination,

(ii) la méthode utilisée pour obtenir les données de remplacement,

(iii) dans le cas de la détermination d'une variable visée au paragraphe 22(3) du présent règlement, la raison qui justifie toute période utilisée pour cette détermination.

SCHEDULE 3

(Subsections 10(1) and 11(2))

List of Fuels and Default Higher Heating Value

	Column 1	Column 2	Column 3
Item	Fuel type	Default higher heating value	Units
1	Distillate fuel oil No. 1	38.78	GJ/kL
2	Distillate fuel oil No. 2	38.50	GJ/kL
3	Distillate fuel oil No. 4	40.73	GJ/kL
4	Kerosene	37.68	GJ/kL
5	Liquefied petroleum gases (LPG)	25.66	GJ/kL
6	Propane[1]	25.31	GJ/kL
7	Propylene	25.39	GJ/kL
8	Ethane	17.22	GJ/kL
9	Ethylene	27.90	GJ/kL
10	Isobutane	27.06	GJ/kL
11	Isobutylene	28.73	GJ/kL
12	Butane	28.44	GJ/kL
13	Butylene	28.73	GJ/kL
14	Natural gasoline	30.69	GJ/kL
15	Motor gasoline	34.87	GJ/kL
16	Aviation gasoline	33.52	GJ/kL
17	Kerosene-type aviation	37.66	GJ/kL
18	Pipeline quality natural gas	0.03793	GJ/m^3 at standard conditions
19	Bituminous Canadian coal — Western	25.6	GJ/tonne
20	Bituminous Canadian coal — Eastern	27.9	GJ/tonne
21	Bituminous non-Canadian coal — U.S.	25.7	GJ/tonne
22	Bituminous non-Canadian coal — other countries	29.9	GJ/tonne
23	Sub-bituminous Canadian coal — Western	19.2	GJ/tonne
24	Sub-bituminous non-Canadian coal — U.S.	19.2	GJ/tonne
25	Coal — lignite	15.0	GJ/tonne
26	Coal — anthracite	27.7	GJ/tonne

ANNEXE 3

(paragraphes 10(1) et 11(2))

Liste des combustibles et pouvoir calorifique supérieur par défaut

	Colonne 1	Colonne 2	Colonne 3
Article	Type de combustible	Pouvoir calorifique supérieur par défaut	Unité
1	Mazout léger nº 1	38,78	GJ/kL
2	Mazout léger nº 2	38,50	GJ/kL
3	Mazout lourd nº 4	40,73	GJ/kL
4	Kérosène	37,68	GJ/kL
5	Gaz de pétrole liquéfié (GPL)	25,66	GJ/kL
6	Propane[1]	25,31	GJ/kL
7	Propylène	25,39	GJ/kL
8	Éthane	17,22	GJ/kL
9	Éthylène	27,90	GJ/kL
10	Isobutane	27,06	GJ/kL
11	Isobutylène	28,73	GJ/kL
12	Butane	28,44	GJ/kL
13	Butylène	28,73	GJ/kL
14	Essence naturelle	30,69	GJ/kL
15	Essence à moteur	34,87	GJ/kL
16	Essence aviation	33,52	GJ/kL
17	Kérosène type aviation	37,66	GJ/kL
18	Gaz naturel de qualité pipeline	0,03793	GJ/m^3 mesuré dans des conditions normales
19	Charbon bitumineux canadien — Ouest	25,6	GJ/tonne
20	Charbon bitumineux canadien — Est	27,9	GJ/tonne
21	Charbon bitumineux non canadien — É.-U.	25,7	GJ/tonne
22	Charbon bitumineux non canadien — autres pays	29,9	GJ/tonne
23	Charbon subbitumineux canadien — Ouest	19,2	GJ/tonne
24	Charbon subbitumineux non canadien — É.-U.	19,2	GJ/tonne
25	Charbon — lignite	15,0	GJ/tonne
26	Charbon — anthracite	27,7	GJ/tonne

Item	Column 1 Fuel type	Column 2 Default higher heating value	Column 3 Units
27	Coal coke and metallurgical coke	28.8	GJ/tonne
28	Petroleum coke from refineries	46.4	GJ/tonne
29	Petroleum coke from upgraders	40.6	GJ/tonne
30	Municipal solid waste	11.5	GJ/tonne
31	Tires	31.2	GJ/tonne
32	Diesel	38.3	GJ/kL
33	Light fuel oil	38.8	GJ/kL
34	Heavy fuel oil	42.5	GJ/kL
35	Ethanol	21	GJ/kL
36	Hydrogen	0.012289	GJ/m^3 at standard conditions

[1] The default higher heating value and the default CO_2 emission factor for propane are only for pure gas propane. The product commercially sold as propane is to be considered LPG for the purpose of these Regulations.

SCHEDULE 4

(Subsection 12(3))

CEMS Auditor's Report — Information Required

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

2 The name, civic address and telephone number of the responsible person.

3 The name, civic address, telephone number and qualifications of the auditor and, if any, the auditor's email address and fax number.

4 The procedures followed by the auditor to assess whether

(a) the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in Section 6.1 of the Reference Method; and

Article	Colonne 1 Type de combustible	Colonne 2 Pouvoir calorifique supérieur par défaut	Colonne 3 Unité
27	Coke de charbon et coke métallurgique	28,8	GJ/tonne
28	Coke de pétrole (raffineries)	46,4	GJ/tonne
29	Coke de pétrole (usines de valorisation)	40,6	GJ/tonne
30	Déchets solides municipaux	11,5	GJ/tonne
31	Pneus	31,2	GJ/tonne
32	Diesel	38,3	GJ/kL
33	Mazout léger	38,8	GJ/kL
34	Mazout lourd	42,5	GJ/kL
35	Éthanol	21	GJ/kL
36	Hydrogène	0,012289	GJ/m^3 mesuré dans des conditions normales

[1] Le pouvoir calorifique supérieur par défaut et le facteur d'émissions de CO_2 par défaut pour le propane s'appliquent uniquement au gaz propane pur. Pour l'application du présent règlement, les produits commerciaux vendus comme étant du propane sont réputés être du GPL.

ANNEXE 4

(paragraphe 12(3))

Rapport du vérificateur sur le SMECE — renseignements à fournir

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 Les nom, adresse municipale et numéro de téléphone de la personne responsable.

3 Les nom, adresse municipale, numéro de téléphone et titres de compétence du vérificateur et, le cas échéant, son numéro de télécopieur et son adresse électronique.

4 Les procédures utilisées par le vérificateur pour évaluer :

a) si l'utilisation du SMECE par la personne responsable était conforme au manuel d'assurance de la qualité et de contrôle de la qualité visé à la section 6.1 de la méthode de référence;

(b) the responsible person complied with the Reference Method and the CEMS met the specifications set out in the Reference Method, in particular, in its Sections 3 and 4.

5 A statement of the auditor's opinion as to whether

(a) the responsible person's use of the CEMS complied with the Quality Assurance/Quality Control manual referred to in Section 6.1 of the Reference Method; and

(b) the responsible person complied with the Reference Method and the CEMS met the specifications set out in the Reference Method, in particular, in its Sections 3 and 4.

6 A statement of the auditor's opinion as to whether the responsible person has ensured that the Quality Assurance/Quality Control manual has been updated in accordance with Sections 6.1 and 6.5.2 of the Reference Method.

SCHEDULE 5

(subsection 24(3))

Permanent Cessation of Electricity Generation Report

1 The unit's registration number, assigned by the Minister under subsection 4(3) of these Regulations.

2 An attestation dated and signed by the responsible person or their authorized official that the unit has permanently ceased generating electricity.

3 The date on which the unit permanently ceased generating electricity.

b) si la personne responsable a suivi la méthode de référence et si le SMECE répondait aux spécifications qui y sont prévues, notamment aux sections 3 et 4.

5 Une déclaration du vérificateur portant qu'à son avis :

a) l'utilisation du SMECE par la personne responsable était conforme au manuel d'assurance de la qualité et de contrôle de la qualité visé à la section 6.1 de la méthode de référence;

b) la personne responsable a suivi la méthode de référence et le SMECE répondait aux spécifications qui y sont prévues, notamment aux sections 3 et 4.

6 Une déclaration du vérificateur portant qu'à son avis la personne responsable a veillé à ce que le manuel d'assurance de la qualité et de contrôle de la qualité soit mis à jour conformément aux sections 6.1 et 6.5.2 de la méthode de référence.

ANNEXE 5

(paragraphe 24(3))

Rapport de cessation définitive de production d'électricité

1 Le numéro d'enregistrement du groupe attribué par le ministre en application du paragraphe 4(3) du présent règlement.

2 Une attestation datée et signée par la personne responsable ou son agent autorisé portant que le groupe a cessé définitivement de produire de l'électricité.

3 La date à laquelle le groupe a cessé définitivement de produire de l'électricité.

Reports of the Commissioner of the Environment and Sustainable Development to the Parliament of Canada

Canadian Net-Zero Emissions Accountability Act— 2030 Emissions Reduction Plan

Report 6

Independent Auditor's Report | 2023

Office of the Auditor General of Canada
Bureau du vérificateur général du Canada

At a Glance

Overall message

The federal government is not on track to meet the 2030 target to reduce greenhouse gas emissions by at least 40% below the 2005 level by 2030. While the 2030 Emissions Reduction Plan included important mitigation measures to reduce emissions, some of these measures, such as the Oil and Gas Emissions Cap and the *Clean Fuel Regulations*, have been delayed. We found that the measures most critical for reducing emissions had not been identified or prioritized.

These are not new findings. The federal government has failed to meet previous emission reduction targets despite the development and implementation of more than 10 climate change mitigation plans since 1990. Canada's current emissions are significantly higher than they were in 1990. Environment and Climate Change Canada had still not taken sufficient steps to improve the transparency and reliability of its economic and emission modelling despite repeated recommendations from our office and modelling experts. Course correction is critical to achieving the target. However, we found that responsibility for reducing emissions was fragmented among multiple federal organizations that were not directly accountable to the Minister of Environment and Climate Change. This means there is no real way for the minister to commit other federal organizations to correcting course to meet the 2030 targets.

While some progress has been made, we are still extremely concerned about the federal government's ability to achieve meaningful progress under the new *Canadian Net-Zero Emissions Accountability Act*. The stakes for failing to mitigate climate change grow ever higher, and the window of opportunity to reduce emissions and meet the 2030 and 2050 targets is rapidly closing.

Key facts and findings

- In March 2022, the Minister of Environment and Climate Change published the 2030 Emissions Reduction Plan, the first plan under the *Canadian Net-Zero Emissions Accountability Act*.
- The act requires the Commissioner of the Environment and Sustainable Development to report by the end of 2024 on the implementation of the measures aimed at mitigating climate change. With the urgent need for rapid, deep emission cuts in Canada's fight against catastrophic climate change, we decided to begin reporting in fall 2023, more than a year earlier than required.
- In the 2030 plan, Environment and Climate Change Canada and Natural Resources Canada made efforts to identify groups that could be disproportionately burdened by measures in the plan and developed some measures to support them.
- Environment and Climate Change Canada projected that Canada would miss the target for reducing emissions. To meet the 2030 target, emissions should be reduced by at least 40% below the 2005 level. In December 2022, the department revised the emission reductions it expected from the 2030 plan from achieving 36.4% below the 2005 level to 34%, missing the 2030 target by an even wider margin.
- Only 45% of the measures in the plan had an implementation deadline.
- The plan did not include a target or expected emission reductions for 95% of its measures. Federal government organizations expected only 43% of measures to have some direct impact on emissions.
- Weaknesses in Environment and Climate Change Canada's economic modelling included overly optimistic assumptions, limited analysis of uncertainties, and lack of peer review.
- The act does not require the minister to achieve the targets. If Canada were to fail again in meeting its target, the act only requires that the minister include the reasons why and propose actions to address the failure.

See **Recommendations and Responses** at the end of this report.