ENBRIDGE
Haris Ginis
Technical Manager
Leave to Construct Applications
Regulatory Affairs

tel 416-495-5827
haris.ginis@enbridge.com
EGIRegulatoryProceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Rd.
North York, ON M1K 5E3
Canada

November 22, 2023

VIA EMAIL and RESS

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. ("Enbridge Gas")
Ontario Energy Board ("OEB") File: EB-2022-0157
Panhandle Regional Expansion Project ("Project")
Hybrid Hearing Undertaking Responses and Transcript Corrections

Consistent with the OEB's Procedural Order No. 8, enclosed are Enbridge Gas's responses to undertakings received during the Hybrid Hearing in the above noted proceeding held November 13 to November 15, 2023. Enbridge Gas has also reviewed the transcripts and notes the enclosed corrections below.

Additionally, consistent with Enbridge Gas's letter dated November 20, 2023, the response to the Federation of Rental-housing Providers of Ontario's ("FRPO") first additional undertaking request within its November 14, 2023, letter can be found in the response to Exhibit J2.4.

In accordance with the OEB's *Practice Direction on Confidential Filings*, Enbridge Gas is requesting confidential treatment of the following exhibit. Details of the specific information and reasons for confidential treatment are set out below.

Exhibit	Confidential Information Location	Brief Description	Basis for Confidentiality
Exhibit J3.3	Page 1 of 1	Commercially Sensitive Information	The redactions relate to information that is commercially sensitive, considered to be Presumptively Confidential, and consists of financial and/or commercial material that Enbridge Gas has consistently treated as confidential. The information consists of pricing information from an individual contractor to perform services related to the Project. Disclosure of this information could prejudice competitive positions and/or interfere with ongoing negotiations.

The unredacted confidential exhibit will be sent separately to the OEB.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Digitally Signed)

Haris Ginis
Technical Manager, Leave to Construct Applications

c.c. Charles Keizer (Torys)
Tania Persad (Enbridge Gas Counsel)
Zora Crnojacki (OEB Staff)
Intervenors (EB-2022-0157)

Transcript Corrections

REFERENCE	**AS STATED**	**CORRECTION**
DAY 2		
Throughout Mr. Gillett's testimony	half	~~half~~ **HAF**
Page 161, line 14	and such a complicated system, is that there's a temple component	and such a complicated system, is that there's a ~~temple~~ **temporal** component

ENBRIDGE GAS INC.

Answer to Undertaking from
Industrial Gas Users Association (IGUA)

Undertaking

Tr: 44

Enbridge to replicate the calculation referred to for the Panhandle Project, and to explain the implications.

Response:

The Project's Stage 1 profitability index ("PI") is 0.48.[1] A total of $149.7 million in CIAC would be required to increase the Project's PI to 0.8. Using the methodology described at the response to Board Panel Question 9 under EB-2018-0013 and provided at pages 129 to 130 of IGUA's compendium (Exhibit K1.9), the hourly contribution factor for the Project would be $891/m3/hr.[2]

Please note that the calculation in Board Panel Question 9 included distribution costs and distribution margin; however, since the Project is entirely a transmission project, distribution costs are not known at this time. As a result, distribution costs and distribution margin have been excluded from the calculation of the Project's hourly contribution factor above.

[1] Exhibit E, Tab 1, Schedule 1, para. 9.
[2] Please note that the methodology used in Board Panel Question 9 under EB-2018-0013 (and used to calculate the figure in this interrogatory response) is not consistent with the OEB-approved Hourly Allocation Factor in EB-2020-0094.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 66

Enbridge (1) to provide figures to the summer operating pressures indicated by the green line; (2) to advise how low could that regulator be set to meet the summer needs of the green line market during summer operations.

Response:

The 2016 summer schematic at page 58 of FRPO's compendium (Exhibit K2.1) displays a green dotted line from Dover Transmission ("Dover") to Dawn Compressor Station ("Dawn"). The "green line" referenced in the undertaking is referring to the NPS 16 Panhandle Line between Dawn and Dover (which has since been replaced by the NPS 36 as part of EB-2016-0186).

1. Table 1 displays the range of actual summer pressures between Dawn and Dover for the NPS 36 and NPS 20, based on the last 5 years of summer data (April through October).

   Table 1 – Range of Actual Summer Pressures between Dawn and Dover, Last 5 Years

Pipeline Segment	Dawn[1] (kPag)	Dover[2] (kPag)
Segment A [NPS 36]	4260 – 6185	3344 – 5413
Segment B [NPS 20]	2302 – 5312	2300 – 5325

   The Panhandle Transmission System's operation is complex and dependent upon the summer demand, Ojibway import volume, and the availability of pipelines and compression due to maintenance activities. As a result, the pressure of the NPS 16 east of Grand Marais and the NPS 20 and NPS 36 east of Dover is variable during summer operations depending on the conditions at the time.

2. As stated above, the Panhandle Transmission System operation is complex and as such Enbridge Gas cannot provide a single set pressure in response to this undertaking.

[1] Measured within the Dawn Compressor Station at the Panhandle measurement locations.
[2] Measured on the 6040 kPag MOP side of Dover Transmission Station.

The Panhandle Lines can operate at different pressures east of Grand Marais Station ("Grand Marais") and east of Sandwich Compressor Station during the summer. The NPS 16 Panhandle Line between Grand Marais and Dover is typically connected to the NPS 20 Panhandle Line between Dover and Dawn while the NPS 20 Panhandle Line from Sandwich Compressor Station to Dover is typically connected to the NPS 36 Panhandle Line between Dover and Dawn.

To control the pressure into the Panhandle Transmission System, Dawn uses control valves, not regulators. These control valves can be bypassed allowing for bi-directional flow paths (in and out) at Dawn.

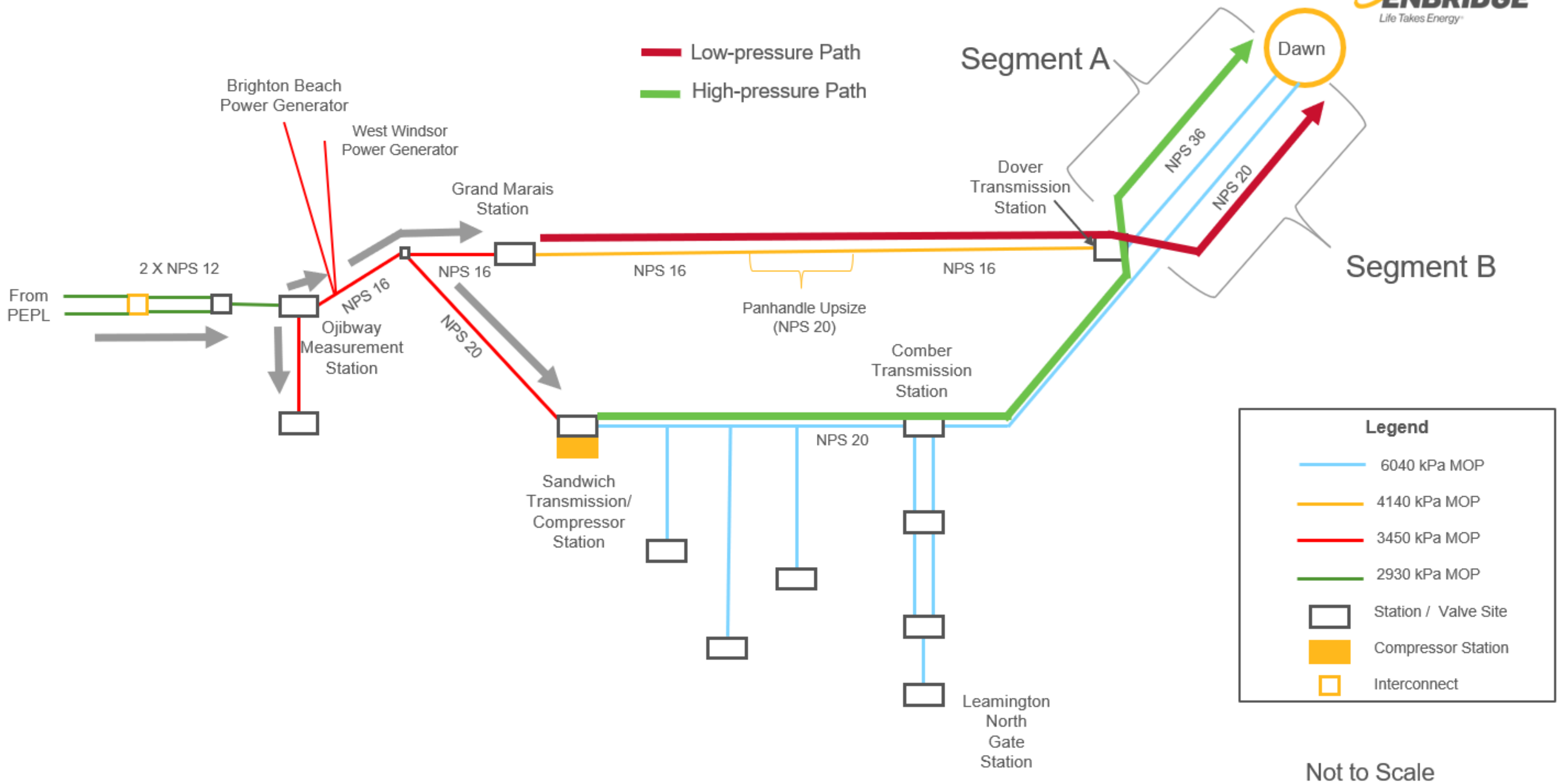
When gas is flowing towards Dawn on the "Low-pressure Path" (please see Figure 1) the gas typically arrives at Dawn at a low pressure. When the pressure is too low, gas flows through Dawn into low-pressure markets if they are available. These low-pressure markets are not always guaranteed to be available during the summer and when they are not, the system cannot flow into Dawn. The path is also not guaranteed due to system set up to manage maintenance activities along the path or at Dawn.

When gas is flowing towards Dawn on the "High-pressure Path" (please see Figure 1), the Dawn control valves are set lower to facilitate the import of gas. The control valves at Dawn must be held at a higher pressure (around 4830 kPag) to maintain reliable service and manage intra-day demand fluctuations of the Panhandle Transmission System.

Increasing the flows through Grand Marais along the NPS 16 Panhandle Line also has the adverse effect of reducing the suction pressure of the Sandwich Compressor station. This reduces the flow capability through the compressor along the NPS 20 Panhandle Line toward Dawn. Increasing the NPS 16 Panhandle Line flow reduces the Sandwich compressor flow rate which does not have the impact of increasing the summer market.

Due to the limitations discussed above, Enbridge Gas defines the minimum summer market as being constrained by the minimum market of the 3450 kPag system between Ojibway Measurement, Grand Marais Station, and Sandwich Compressor Station plus the compressor flow capability.

Figure 1


Low-pressure Path
High-pressure Path
Segment A
Segment B
Dawn
Brighton Beach Power Generator
West Windsor Power Generator
Grand Marais Station
Dover Transmission Station
2 X NPS 12
From PEPL
NPS 16
Ojibway Measurement Station
NPS 20
NPS 16
NPS 16
NPS 16
Panhandle Upsize (NPS 20)
NPS 36
NPS 20
Comber Transmission Station
NPS 20
Sandwich Transmission/ Compressor Station
Leamington North Gate Station
Legend
6040 kPa MOP
4140 kPa MOP
3450 kPa MOP
2930 kPa MOP
Station / Valve Site
Compressor Station
Interconnect
Not to Scale

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 68

1) Enbridge to explain the 2275 constraint at Leamington North; 2) to explain whether valving exists that would allow the south line to operate separately for the north line

Response:

1) The 2275 kPa minimum inlet pressure at the Leamington North Gate Station is required to maintain pressure in the downstream 1900 kPa distribution system and to maintain a high-pressure contract rate customer minimum pressure requirement. Please see response at Exhibit JT2.8.STAFF-1, part c) for more information.

2) Enbridge Gas interprets the “south line” and “north line” to mean the NPS 20 Panhandle Line (between NPS 16/20 Junction and Dawn) and the NPS 16 / 36 Panhandle Line (between NPS 16/20 Junction and Dawn), respectively.

   Yes, there is valving in place where the “south” and “north” Panhandle Lines can be operated separately east of Sandwich Transmission / Compressor station and Grand Marais Station. Please see response at Exhibit J2.2 for additional details.

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 70

Enbridge to provide an expanded scenario for summer showing flow from Panhandle line into the Sarnia south line.

Response:

The NPS 20 and NPS 36 Panhandle Lines are connected to, and already optimized to serve, the Sarnia South Line from the Dover Center take-off through the Dover Center Station and Chatham East Line. As such, there is no additional information to provide. Please see reference point 6 at Exhibit B, Tab 2, Schedule 1, Attachment 1 for information regarding where the Dover Center take-off is located.

Additionally, on November 14, 2023, FRPO filed a letter requesting that Enbridge Gas provide responses to additional undertaking requests. On November 20, 2023, Enbridge Gas filed a letter responding to FRPO which stated that the Company would provide a response to FRPO's first additional undertaking request with the Company's hybrid hearing undertaking responses. Please see below for Enbridge Gas's response to FRPO's first additional undertaking request:[1]

Enbridge Gas interprets "Table 4" as Table 4 at Exhibit C, Tab 1, Schedule 1, p. 18.

Please see Attachment 1 for the schematic and table showing the requested pressures and flows related to Hybrid Alternative 1: 17.86 km NPS 36 with +21 TJ/d incremental Ojibway supply for Winter 2024/2025.

Please see Attachment 2 for the schematic and table showing the requested pressures and flows related to Hybrid Alternative 2: 16.20 km NPS 36 with +21 TJ/d incremental Ojibway supply for Winter 2024/2025.

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[1] FRPO's first additional undertaking request: "For the Hybrid Alternatives in Table 4, please provide the simulation results in the same format as the base case of Exhibit I.FRPO-18. These simulations should already be completed to develop the incremental capacity shown in the table."

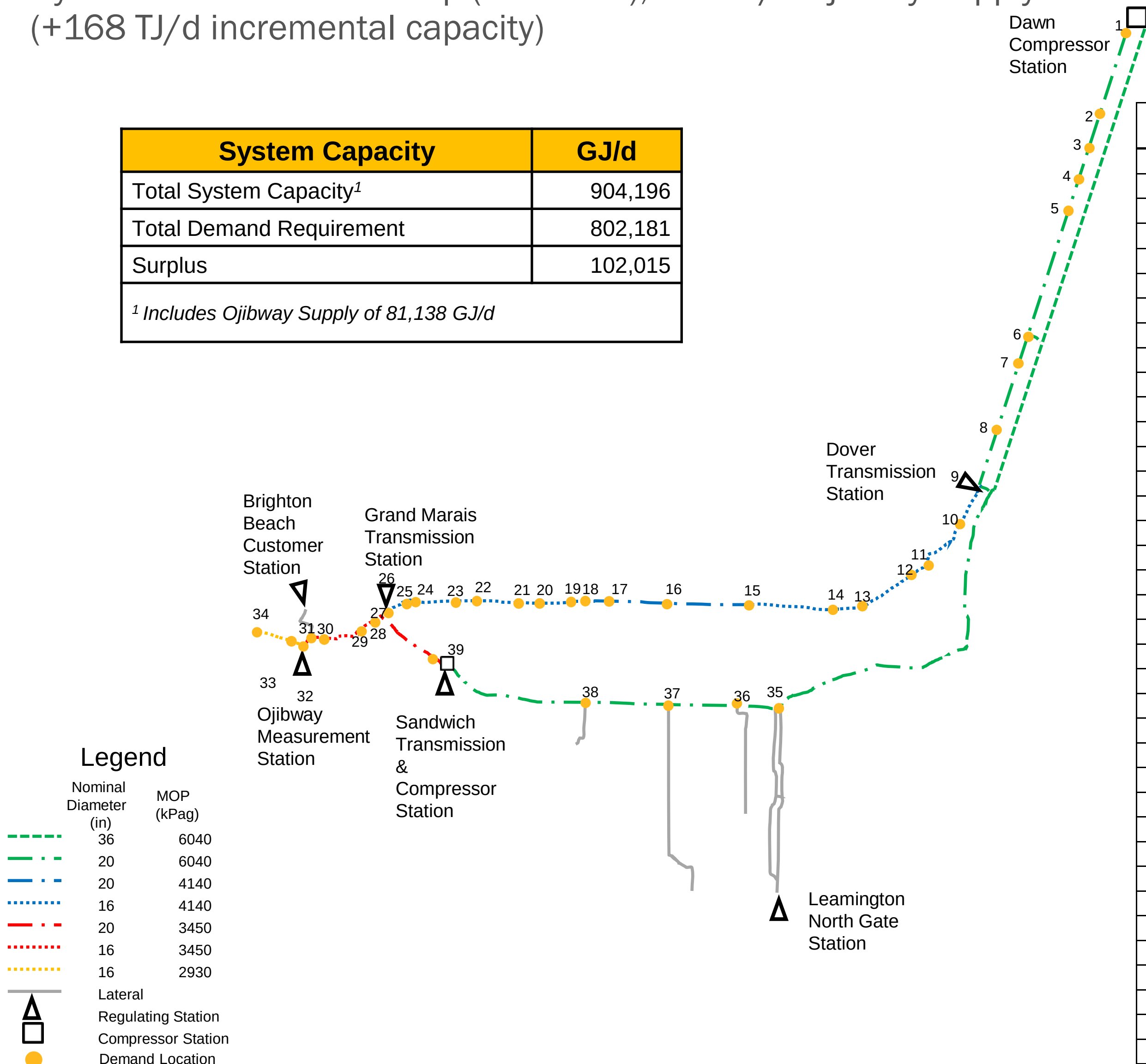
Panhandle Transmission System

Winter Design Day Schematic
Winter 2024/2025
Hybrid 1: With NPS 36 Loop (17.86 km), +21 TJ/d Ojibway Supply (+168 TJ/d incremental capacity)

ENBRIDGE

System Capacity	GJ/d
Total System Capacity[1]	904,196
Total Demand Requirement	802,181
Surplus	102,015

[1] Includes Ojibway Supply of 81,138 GJ/d



	Station Name	Kilometre Post (km)	Demand (GJ/d)	Pressure (kPag)
1	Dawn / Dawn West Lines	0	20251	5978
2	Tolloch & Mandaumin	4.3	0	5958
3	Chatham Gore Conc 4	10	0	5933
4	Lindsay Tile Yard	12.9	44	5920
5	Tupperville	15.2	3984	5910
6	Dover Centre	27	82442	5849
7	Cartier	29.4	0	5839
8	Bechard	34.9	2110	5818
9	Dover Transmission	40	0	5796
10	Bradley	44.1	0	3926
11	T. N. Lighthouse	48.9	200	3732
12	Tilbury North TO	50.7	2934	3657
13	Tilbury Conc 2	55.8	0	3421
14	Stoney Point	58.7	1282	3283
15	St Joachim	65.4	337	2957
16	Belle River	72.6	4280	2838
17	Puce	77.8	2302	2754
18	Wallace	79.4	131	2724
19	Patillo	80.9	5087	2700
20	Elmstead	83	1650	2567
21	Manning	85.2	7691	2426
22	Lauzon TO	88.9	45805	2192
23	Ford Marentette TO	90.7	2071	2150
24	TransAlta / East Windsor TO	94.2	37220	2099
25	Walker	94.9	38746	2070
26	Grand Marais	97.1	27633	2069
27	NPS 16/20 Interconnect	108.1	0	2061
28	Bruce	109.4	5774	2045
29	California	111.4	17518	1979
30	Titcombe	114.9	7583	1901
31	Brighton Beach and WWP	116.2	129371	1828
32	Ojibway Measurement	116.6	29193	1880
33	Ojibway Valve	117.9	0	1922
34	River Crossing	118.6	0	1949
35	Comber	71.2	170753	4746
36	Mersea	75	44534	4649
37	Kingsville	80	89822	4549
38	Essex	88.1	6986	4484
39	Sandwich Transmission	101.1	14448	4395
Total			**802181**	

W24/25 Hybrid Alternative: 17.86 km NPS 36 and +21 TJ/d Ojibway Supply	Throughput	Direction	Requested Pressure
Location	**GJ/d**	**Flow**	**kPag**
Dawn Supply	721,043	Westerly	
Dover Transmission Station to NPS 16	170,193	Westerly	
Dover Transmisssion Station to NPS 20/36	442,020	Westerly	
Leamington North Gate Station	14,260	South	3656
Grand Marais Station	20,457	Westerly	
Sandwich Station	129,925	Westerly	
Ojibway Measurement to Windsor	81,138	North/South	
Detroit River Crossing (Ojibway Supply)	81,138	Easterly	

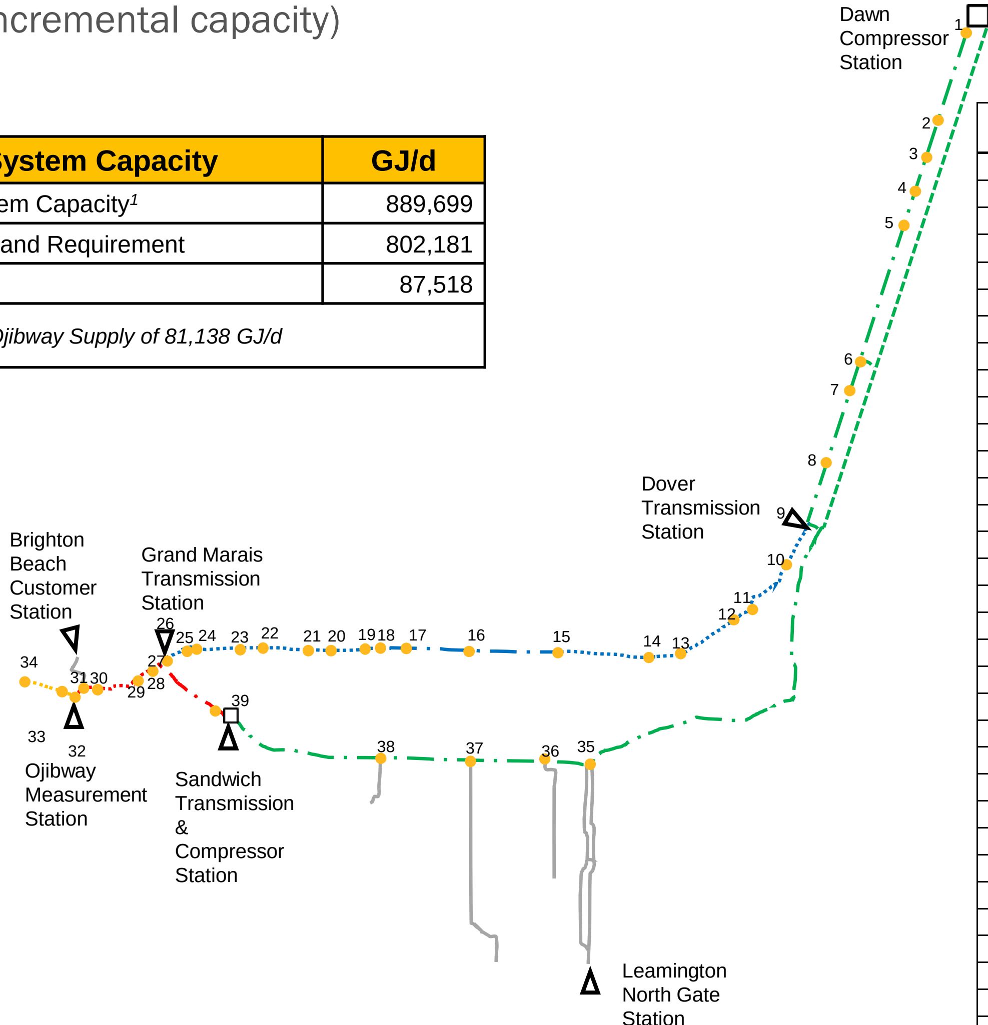
Panhandle Transmission System

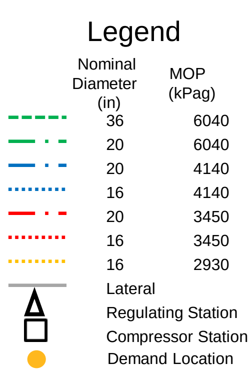
Winter Design Day Schematic
Winter 2024/2025
Hybrid 2: With NPS 36 Loop (16.20 km), +21 TJ/d Ojibway Supply (+153 TJ/d incremental capacity)

ENBRIDGE

System Capacity	GJ/d
Total System Capacity[1]	889,699
Total Demand Requirement	802,181
Surplus	87,518

[1] Includes Ojibway Supply of 81,138 GJ/d





	Station Name	Kilometre Post (km)	Demand (GJ/d)	Pressure (kPag)
1	Dawn / Dawn West Lines	0	20251	5978
2	Tolloch & Mandaumin	4.3	0	5958
3	Chatham Gore Conc 4	10	0	5933
4	Lindsay Tile Yard	12.9	44	5920
5	Tupperville	15.2	3984	5910
6	Dover Centre	27	82442	5850
7	Cartier	29.4	0	5840
8	Bechard	34.9	2110	5818
9	Dover Transmission	40	0	5797
10	Bradley	44.1	0	3926
11	T. N. Lighthouse	48.9	200	3732
12	Tilbury North TO	50.7	2934	3657
13	Tilbury Conc 2	55.8	0	3421
14	Stoney Point	58.7	1282	3283
15	St Joachim	65.4	337	2957
16	Belle River	72.6	4280	2838
17	Puce	77.8	2302	2754
18	Wallace	79.4	131	2724
19	Patillo	80.9	5087	2700
20	Elmstead	83	1650	2567
21	Manning	85.2	7691	2426
22	Lauzon TO	88.9	45805	2191
23	Ford Marentette TO	90.7	2071	2150
24	TransAlta / East Windsor TO	94.2	37220	2099
25	Walker	94.9	38746	2070
26	Grand Marais	97.1	27633	2069
27	NPS 16/20 Interconnect	108.1	0	2061
28	Bruce	109.4	5774	2045
29	California	111.4	17518	1979
30	Titcombe	114.9	7583	1901
31	Brighton Beach and WWP	116.2	129371	1828
32	Ojibway Measurement	116.6	29193	1880
33	Ojibway Valve	117.9	0	1921
34	River Crossing	118.6	0	1949
35	Comber	71.2	170753	4612
36	Mersea	75	44534	4512
37	Kingsville	80	89822	4409
38	Essex	88.1	6986	4343
39	Sandwich Transmission	101.1	14448	4250
Total			**802181**	

W24/25 Hybrid Alternative: 16.20 km NPS 36 and +21 TJ/d Ojibway Supply	Throughput	Direction	Requested Pressure
Location	**GJ/d**	**Flow**	**kPag**
Dawn Supply	721,043	Westerly	
Dover Transmission Station to NPS 16	170,193	Westerly	
Dover Transmisssion Station to NPS 20/36	442,020	Westerly	
Leamington North Gate Station	14,260	South	3483
Grand Marais Station	20,457	Westerly	
Sandwich Station	129,925	Westerly	
Ojibway Measurement to Windsor	81,138	North/South	
Detroit River Crossing (Ojibway Supply)	81,138	Easterly	

ENBRIDGE GAS INC.

Answer to Undertaking from
Federation of Rental-housing Providers of Ontario (FRPO)

Undertaking

Tr: 89

Enbridge to advise its view of legal grounds on rover's contract renewal rights in 2026.

Response:

The C1 Transportation Contract with Rover Pipeline LLC contains the following Special Provisions:

> Subject to the provisions of this Contract, this Contract will continue in full force and effect beyond the Initial Term, automatically renewing for a period of one (1) year, and every one (1) year thereafter, subject to notice in writing by Shipper of termination at least two (2) years prior to the expiration thereof.

Based on the above, there is no mechanism that would allow Enbridge Gas to unilaterally terminate the contract.

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 102

EGI to explain the derivation of system average heating value, to clarify its impact on the forecast.

Response:

There are three heating value zones used by Enbridge Gas (EGD rate zone, North rate zone, and South rate zone). The South rate zone System Wide Average Heating Value (“SWAHV”) is used for the Panhandle Transmission System.

The South rate zone SWAHV is calculated by dividing the “Annual Quantity” for the South rate zone in energy units (GJ) by the “Annual Quantity” for the South rate zone in volume (10^3m^3).

The “Annual Quantity” for each energy and volume are calculated by removing annual South rate zone Deliveries[1] (in either energy or volume) from the annual South rate zone Receipts[2] (in either energy or volume).

The South rate zone SWAHV is updated on an annual basis using gas measurement values between January 1 to December 31. The updated values are posted effective April 1 of each year[3].

The SWAHV is used to convert between volume and energy. As the heat value changes, so will customer volume demand from the pipeline.

Since the demand forecast and system capacity is communicated in energy units (TJ/d), a different SWAHV will change the energy demand forecast and system capacity results, however the volumetric demand and volumetric system capacity in the forecast is not impacted.

[1] Deliveries – amount of gas delivered from the utility to interconnects.
[2] Receipts – amount of gas received into the utility from interconnects.
[3] Historical values are posted on Enbridge Gas’s website (https://www.enbridgegas.com/storage-transportation/doing-business-with-us/unit-measure-conversion-information)

ENBRIDGE GAS INC.

Answer to Undertaking from
Energy Probe Research Foundation (EP)

Undertaking

Tr: 129

EGI to comment on customer knowledge on proposed cost allocations for phase 3.

Response:

Enbridge Gas has provided the cost allocation and unit rates for the Project based on current OEB-approved cost allocation methodology in response at Exhibit I.IGUA.2, Attachment 1.

The levelized impact of the Project, using an updated cost allocation methodology proposed in the 2024 Rebasing proceeding, is included in the revenue deficiency figure in the Decision on Settlement Proposal for Phase 1 of the 2024 Rebasing proceeding[1]. The final revenue deficiency will be determined once the Decision on Phase 1 of the 2024 Rebasing proceeding is issued; however, customers will not be able to disaggregate the unit rate impacts related to the Project specifically from the final revenue deficiency.

The cost allocation of the Project, including all other Panhandle Transmission System costs, will be reviewed as part of Phase 3 of Enbridge Gas's 2024 Rebasing proceeding. This will be the first opportunity for customers to see the unit rate impacts directly attributable to the Project.

[1] EB-2022-0200, Decision on Settlement Proposal, dated August 17, 2023. Page 2, reference 5.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 134

EGI to provide details for attachment forecasts, including breakdown by year

Response:

Table 1 displays the forecast attachments estimated to be new construction versus conversions. The table also displays conversion attachments as a percentage of total forecasted attachments.

Table 1

Year	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Construction Attachments	1512	1515	1500	1473	1446	1387	1332	1277	1231
Conversion Attachments	84	78	72	65	59	53	48	43	22
Total Attachments	**1596**	**1593**	**1572**	**1538**	**1505**	**1440**	**1380**	**1320**	**1253**
Conversion Attachments as Percentage of Total Attachments	5%	5%	5%	4%	4%	4%	3%	3%	2%

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 148

EGI to provide the ratio of annual to peak for residential and the ratio of annual to peak for the group that includes greenhouses; within the agriculture sector, to advise what percentage constitutes greenhouse demand.

Response:

Lines 1 and 2 in Table 1 provide the ratio of annual savings to peak hour savings for the residential and agriculture segment, respectively, based on the results of Posterity's analysis.

It should be noted that the measure mix included within the agriculture analysis includes a measure that impacts annual consumption but not peak (i.e., recommissioning) and an end-use that is applicable to other agriculture building types which are more process-based rather than temperature-dependent (i.e., process heating). Line 3 in Table 1 provides the ratio after the exclusion of the aforementioned measure and end-use from the analysis.

For additional clarity, all agriculture measures reduce energy consumption and energy peak for the Industrial HVAC end-use, and the hours-use factors for this end-use have been developed using a weather-related load shape, which takes into consideration temperature dependency.

Table 1

Line	Segmentation	Annual Consumption Savings (m3) / Peak Hour Savings (m3/hr)
1	Residential sector	1,273
2	Agriculture segment	5,537
3	Agriculture segment (adjusted)	1,216

Within the general service agriculture segment, greenhouses account for approximately 75% of the demand.

ENBRIDGE GAS INC.

Answer to Undertaking from
Environmental Defence (ED)

Undertaking

Tr: 159

For EGI or posterity on behalf of EGI to extrapolate the peak demand for the contract customers based on the work that's already been done for posterity to provide, on a best-efforts basis.

Response:

Enbridge Gas has extrapolated Posterity's analysis of the general service market's peak demand reduction opportunity from ETEE to the contract market. To do this, a peak hour savings percentage was derived by taking the total peak hour savings from the industrial sector (general service market) in 2029 and dividing it by the total peak hour industrial sector demand (general service market) in 2029. This percentage was then applied to the forecasted contract load (excluding power generators) for Winter 2023/2024 of 316 TJ/day, as shown in Table 2 at Exhibit B, Tab 1, Schedule 1. The extrapolated peak hour savings is 21 TJ/day by 2029. For clarity, the agriculture segment is a sub-segment under the industrial sector.

It should be noted that the Posterity analysis was completed for general service customers only, and the savings were derived based on the customer mix within the general service customer base and by mapping the appropriate measures and end-uses to each specific customer segment. The mix of general service customers within the industrial sector differs from the mix of contract customers. Contract customers are more sophisticated than general service customers, and the natural gas demands expressed by contract customers via the EOI process are already 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).[1]

Furthermore, energy efficiency that is realized in the contract market can reduce overall gas consumption throughput but does not always result in a reduction in customer contract demand. Using the greenhouse sector as an example, reductions in annual energy requirements do not always translate to reductions in peak demand

[1] Exhibit B, Tab 1, Schedule 1, Attachment 8, p. 6.

requirements for several reasons. First, any peak hour efficiencies are typically used by the customer to expand operations and/or increase production. Second, greenhouse growers must continue to ensure that their crop thrives as temperatures approach design day and/or as they plan to face challenging weather conditions.

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 186

EGI to advise (a) the difference between lump sum and fixed-price contract structure; (b) to advise of the meaning of unit price contract in the context of a defined pipeline of a certain length and location.

Response:

a) There is no difference between a lump sum contract structure and a fixed-price contract structure. A lump sum is a fixed price in which contractors agree to a pre-determined price for a fixed unit of work.

b) A unit price contract structure consists of pre-determined prices for an estimated unit of work (e.g., cost to supply and install one (1) tonne of sand as required). Unit prices include the necessary labour, equipment, contractor-supplied materials, subcontractor support and ancillary costs (e.g., profit, overheads, etc.) to complete a unit of work.

ENBRIDGE GAS INC.

Answer to Undertaking from
Pollution Probe (PP)

Undertaking

Tr: 204

EGI to indicate those contracts that have been signed, including conditions precedent, the sector from which they have arrived, including identifying the line number that appears on whatever the particular undertaking or interrogatory response that that relates to, together with any particular provisions that relate to the payment of ciac or any other provision that relates to the outcome of this proceeding, or any provisions that are somehow related to this particular application.

Response:

Enbridge Gas has executed three additional distribution contracts since the Company filed its response at Exhibit I.STAFF.24, part a) which had identified one executed distribution contract at the time. All three additional executed distribution contracts are existing customers that are expanding within the greenhouse sector.

The three additional executed distribution contracts consist of standard contracts with typical provisions and conditions. The standard contracts are provided in response at Exhibit I.PP.5, Attachment 1. The three additional executed distribution contracts do not contain non-standard provisions or conditions, including provisions or conditions regarding a CIAC requirement related to the Project and/or regarding the outcomes of the Project's OEB proceeding.

Please see Table 1 for the demand and term for the three additional executed distribution contracts.

Table 1

Contract Demand (TJ/d)	**Contract Term (Years)**
1.7	12
1.3	5
1.6	10

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 62

To provide an estimate of the cost of the Richardson Side Road endpoint valve site and how the cost was determined.

Response:

The cost for the Richardson Side Road valve site was estimated using drawings completed to the 90% design detail. Contractor costs were estimated using the average of the three most competitive proponents from both a cost and technical evaluation perspective. Material costs were estimated based on the corresponding Bill of Materials to the design.

Table 1

Item No.	Cost Description	Richardson Station
1	Materials	$ 2,500,000
2	Labour, External Permitting and Land, and Outside Services	$ 6,320,000
3*	Contingency	$ 720,000
4*	Interest During Construction	$ 420,000
5	Total Direct Capital Costs	$ 9,960,000
6*	Indirect Overheads	$ 2,400,000
7	Total Project Costs	$ 12,360,000

* Items 3, 4 & 6 are not included within proponent proposals. For the purpose of Table 1, these figures have been developed using the prorated percentages from the Project cost estimate, proportional to the cost of the valve site.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 63

To break out additional costs associated with the provision of seven trench-less crossings, and how the cost was determined.

Response:

Trenchless crossings are defined as crossings where typical open trench excavations are not permitted. These include, but are not limited to, major bodies of water or waterways with environmental sensitivities, railway crossings, major roads, etc. Not all trenchless installations are comparable and as such there is no standard/typical cost per trenchless crossing. Multiple factors influence the cost including, but not limited to, geotechnical information, method of install (auger bore vs. horizontal directional drill), length and required depth of crossing, environmental requirements, and other crossing complexities.

Based on the average unit price of the top three most competitive proponents, the total cost for trenchless crossings is estimated to be approximately $21 million. Please see Table 1 for a comparison of the trenchless crossing costs for the Project compared to the Dawn to Corunna Replacement Project (EB-2022-0086).

Table 1

Item	**Panhandle Regional Expansion Project (EB-2022-0157)** *(a)*	**Dawn to Corunna Replacement (EB-2022-0086)** *(b)*	**Difference** *(c) = (a) – (b)*
Total Trenchless Crossings	8	1	7
Total Trenchless Crossings Cost	$21 million	$5 million	$16 million

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 67

To provide an updated cost estimate for Table 1 in SEC 2, based upon only the lowest-cost proponent qualified; to file on a confidential basis.

Response:

As per response at Exhibit I.SEC.2, part b), the average proposal price from the top three most competitive proponents was used for the Project cost estimate displayed in Table 1 in response at Exhibit I.SEC.2, part a). Please see Table 1 for the lowest proposal price from those three most competitive proponents.

Table 1 – Project Cost Estimate from Lowest of Top 3 Proponents

Item No.	Cost Description	19km of NPS 36 Pipeline and Ancillary Facilities
1	Materials	$ [redacted]
2	Labour, External Permitting and Land, and Outside Services	$ [redacted]
3*	Contingency	$ [redacted]
4*	Interest During Construction	$ [redacted]
5	Total Direct Capital Costs	$ [redacted]
6*	Indirect Overheads	$ [redacted]
7	Total Project Costs	$ [redacted]

* Items 3, 4 & 6 are not included within proponent proposals. For the purpose of Table 1, these figures have been developed using the prorated percentages from the Project cost estimate in response at Exhibit I.SEC.2, part a).

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 68

EGI to describe its standard practice with the top three most competitive proponents.

Response:

The method used by Enbridge Gas to develop project cost estimates for leave to construct applications varies on a case-by-case basis. The intention of project cost estimates is to provide the best representation of estimated costs based on the information available at the time. Factors influencing how Enbridge Gas determines project cost estimates include the number of qualified bids received, the size and complexity of the project itself, and the certainty regarding the inputs into the project cost estimate process. In the case of this Project, Enbridge Gas established three (3) qualified competitive proponents through the RFP evaluation process (which considers multiple criteria in addition to cost) and chose the average of those three as the best representation of estimated project costs for the Project.

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 70

EGI to file a risk analysis showing specific risks, contingencies, and likely impacts on the project

Response:

The top risks identified as part of the Project's risk assessment were delayed land acquisition and delayed OEB approval of the Project. These risks could have a direct impact on the Project's schedule and could impact the estimated Project cost if schedule compression is required to maintain the target in-service date.

Enbridge Gas uses an established contingency estimating methodology based on AACE® International RP 10S-90 recommended practice. Enbridge Gas's practice for contingency estimating uses the combination of a parametric model (for treatment of systemic risks) and expected value plus critical path modeling (for treatment of project-specific risks). Please see Attachment 1 for the Project's contingency report summary which was used to establish the $20.8 million contingency figure in Table 1 in response at Exhibit I.SEC.2. Enbridge Gas continues to monitor contingency throughout the lifecycle of the project.

Enbridge Gas also considers asset utilization risk and possible mitigations as it relates to adverse impacts of changing market fundamentals and customer preferences.

The proposed Project is a loop of the existing NPS 20 pipeline (i.e., the proposed project directly parallels the existing NPS 20 pipeline) which will provide flexibility in managing the integrity of the existing NPS 20 pipeline in the future. In a scenario where customer demands decline in the long-term, Enbridge Gas may be able to avoid future integrity projects on the existing NPS 20 pipeline by retiring the looped section of the existing pipeline while maintaining service to customers using the Project facilities. This would have the dual benefit of potentially avoiding the cost of integrity work while maintaining the utilization of the Project facilities.

Additionally, the Panhandle Transmission System currently utilizes 60 TJ/d of firm deliveries at Ojibway to reduce the facilities required from Dawn. Once the proposed Project is in service, should natural gas demand decrease over the long-term, Enbridge Gas can reduce its reliance on gas supply deliveries to Ojibway from PEPL and replace that supply with deliveries from Dawn. This would result in a higher utilization of the proposed Project and an efficient use of the asset.

In reference to Commissioner Moran's questions of the Enbridge Gas panel during the hybrid hearing related to the Company's willingness to bear the financial risk of underutilization of the proposed facilities (3 Tr 126 to 128), Enbridge Gas submits that the current demand forecast and depreciation rates underpinning the Application appropriately reflect the known energy transition risk at this time. Although a number of pathway scenarios have been created by various parties, none provide definitive timelines and forecastable impacts on demand, and there is currently no government policy that describes this level of risk.

If a reliable forecast of energy transition-related impacts on demand were available, Enbridge Gas would be willing to take on the risk of future underutilization as long as it also had the ability to mitigate that risk. Mitigations would include the full ability to adjust the timing and amount of depreciation to be covered in rates according to the risk level.

CONTINGENCY DASHBOARD

ENBRIDGE

Panhandle Regional Expansion Project

Document #: PRJ-PD-TOOL-003

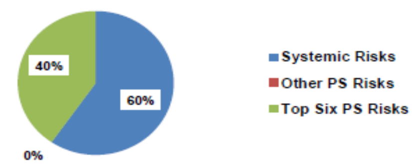
Session Date:	2022-11-24
Issued Date:	2023-03-09

Risk Lead:	
Cost Engineering Lead:	Nicholas Menon

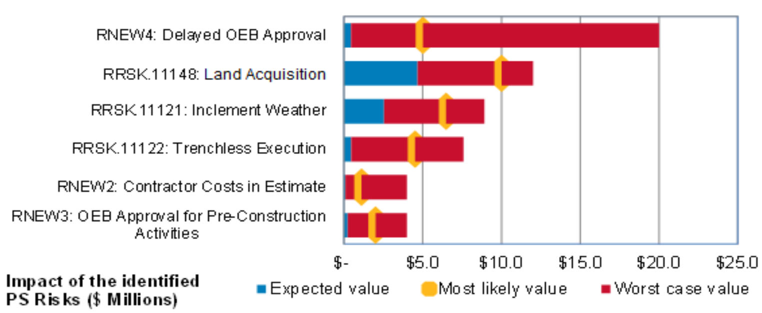
A. Cost Contingency Summary CAD

	Cost ($000s)	Percentage of Cost	Confidence (%)
Base Estimate	$ 252,786		19%
Fixed Cost	$ 63,870	25.3%	
Cost Contingency (P50)	**$ 20,779**	**8.2%**	
Reference Estimate	$ 273,565		50%
Accuracy Range	$ 245,329	-10.3%	10%
	$ 307,333	12.3%	90%
Contingency as % of non-fixed costs		11.0%	

B. Cost Impact Breakdown of Risks



C. Cost Impact of Top Six Project Specific Risks



D. Schedule Contingency Summary - Unmitigated*

	Execution Duration (weeks)	Percentage of Schedule	Confidence (%)	Dates
Base Duration	157			
Schedule Contingency (P50)	**14**	**9%**		
Reference Duration	171		50%	2025-02-09
In-Service Date			7%	2024-11-01
Accuracy Range	158	-7.3%	10%	2024-11-13
	184	7.9%	90%	2025-05-14
Contingency as % of remaining schedule			14%	

** Unmitigated means that a) Schedule risks may be mitigated by achieving more project definition (more development) and/or using cost contingency; and b) Float is ignored (not part of contingency).*

E. Observations and Recommendations

1.- The following risks have been identified as having an overwhelming cost impact (*), and should be monitored and managed as closely as possible to reduce potential cost impacts:

#RRSK.11448: Land Acquisition

2.- The following risks have been identified as having an overwhelming schedule impact (*), and should be monitored and managed as closely as possible to reduce potential schedule impacts:

#RRSK.11448: Land Acquisition
#RNEW1: Richardson Station Species at Risk Habitat

(*) Overwhelming Cost or Schedule Impact:
An overwhelming impact happens when a risk consumes all or most of the contingency fund if it occurs, leaving inadequate contingency for other risks. It has the following characteristics:
- The most likely cost of the risk (if it were to occur) would cause an impact larger than 40% of the overall P50 contingency;
- or its worst likely case would cause an impact larger than 100% of the overall P50 contingency;
- or its worst likely case would cause an impact larger than 10% of the base cost or base schedule
Risks that may cause overwhelming impacts should be carefully monitored and mitigated

ENBRIDGE GAS INC.

Answer to Undertaking from
Ontario Energy Board Staff (STAFF)

Undertaking

Tr: 75

To file details related to the greener homes grant program uptake, confidentially if required.

Response:

Please see Table 1 and Table 2 for the requested information regarding electric air source heat pump ("ASHP") uptake within the Panhandle Project area for the HER+ program (inclusive of Canada Greener Homes Grant).

Table 1
2023 Total Number of Participants in the Project Area that Installed an Electric ASHP via the HER+ Program

Primary Fuel Type (Before to After)	**# of Participants**
Other Fuel Source to Natural Gas	6
Natural Gas to Natural Gas	511
Natural Gas to Electricity	21
Other (Neither Natural Gas Before or After)	44
Total	**582**

Table 2
Subset of Table 1 (2023 Monthly HER+ Total Participants and 2023 Monthly HER+ "Natural Gas to Electricity" Conversion Participants)

Month (Year 2023)	**Total HER+ Participants**	**HER+ Participants Converting from Natural Gas to Electric ASHPs for Space Heating**
Jan	13	3
Feb	23	2
Mar	49	1
Apr	61	1
May	84	4
Jun	104	3
Jul	117	5
Aug	100	2
Sept	31	0
Oct	0	0
Total	**582**	**21**

Notes:
1. Data available/provided up to Oct 12, 2023.
2. Data based on the space heating fuel fields before and after participation – i.e., 1st audit (D audit) versus 2nd audit (E audit).
3. Data is for all participants that have any type of electric ASHP (traditional ASHP or cold climate ASHP).
4. Table 1 and Table 2 data has been recorded for all HER+ files with an electric ASHP listed and is based solely on the data collected by the auditor. No other verification has been performed. Month in Table 2 is based on the date of the 2nd audit (E audit).