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 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.

COMPENDIUM OF THE SCHOOL ENERGY COALITION

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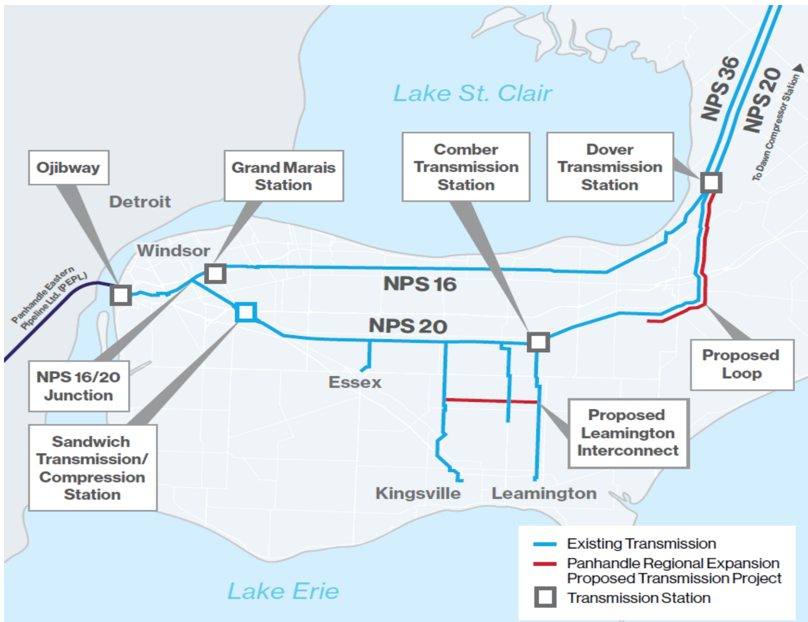
Counsel for the School Energy Coalition

Figure 1: Map of Proposed Project Facilities



4. The Project will commence at the existing Enbridge Gas Dover Transmission Station located 40 km southwest of the Dawn Hub at Balmoral Line and Town Line Road in Chatham-Kent, Ontario. The pipeline will loop the existing NPS 20 Panhandle Line, following existing easements where possible, for approximately 19 km to Richardson Sideroad in Lakeshore, Ontario where it will tie into the existing NPS 20 Panhandle Line at a new valve site station. Additionally, the Project will include construction of a new NPS 16 pipeline interconnecting the Kingsville East Line, Mersea Line, Leamington North Loop, and Leamington North Line along with their required valve site stations.

5. The required pipeline, station, measurement, and pressure regulation facilities for the Project are listed in Table 1 below. Further details on the facility specifications can be found within the “Design Specifications & Testing Procedures” section of this Exhibit.

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

Table 3: NPV Calculation

Stage	NPV ($millions)
1	($95)
2	$214 to $335
3	$223
Total	$342 to $463

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, the Project has a net present value of $342 million to $463 million and is economically feasible.

26. On February 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):[3]

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

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. /U
134 are appropriate for the purposes of evaluating the Project. Based on these tests,

Panhandle Regional Expansion Project
Project Cost
($ Millions)

		NPS 36			NPS 16				
Item No.	Cost Description	Mainline	Stations	Subtotal	Mainline	Stations	Subtotal	Dawn	Total
1	Materials	$ 28.3	$ 3.5	$ 31.8	$ 6.9	$ 6.3	$ 13.2	$ 24.8	$ 69.8
2	Labour	0.5	-	0.5	0.1	0.1	0.2	0.2	0.9
3	External Permitting and Land	15.3	0.2	15.5	10.0	0.3	10.3	-	25.8
4	Outside Services	80.4	4.5	84.9	13.4	13.4	26.8	23.0	134.7
5	Contingency	13.1	0.9	14.0	3.2	2.0	5.2	5.2	24.4
6	Interest During Construction	2.3	0.2	2.5	0.8	0.3	1.1	1.0	4.6
7	Total Direct Capital Cost	139.9	9.3	149.2	34.4	22.4	56.8	54.2	260.2
		-	-	-	-	-	-	-	-
8	Indirect Overheads	29.7	2.0	31.7	6.6	4.4	11.0	11.5	54.2
9	Total Project Cost	$ 169.6	$ 11.3	$ 180.9	$ 41.0	$ 26.8	$ 67.8	$ 65.7	$ 314.4

Panhandle Regional Expansion Project
Project Cost
($ Millions)

		NPS 36				
Item No.	Cost Description	Mainline	Stations	Subtotal	Dawn	Total
1	Materials	$ 28.3	$ 2.2	$ 30.5	$ 26.4	$ 57.0
2	Labour	2.7	0.2	2.8	0.9	3.8
3	External Permitting and Land	17.4	-	17.4	-	17.4
4	Outside Services	130.8	5.4	136.2	42.0	178.1
5	Contingency	13.9	0.6	14.5	6.3	20.8
6	Interest During Construction	6.4	0.3	6.7	5.4	12.1
7	Total Direct Capital Cost	199.5	8.6	208.1	81.1	289.2
8	Indirect Overheads	48.0	2.1	50.1	18.7	68.8
9	Total Project Cost	$ 247.5	$ 10.7	$ 258.2	$ 99.8	$ 358.0

Calculation of Revenue (Transmission Margins)

PREP - Panhandle Regional Expansion Project
InService Date: Nov-01-2024

Line	Project Year ($000's)		1	2	3	4	5	6	7	8	9	10 +
	Transmission costs are recovered from Contract rate classes based on Firm Contract Demand (CD)											
	The deemed incremental revenue is based on the capacity created by the Project											
	Contract Methodology: Total CD * 12 *Transmission Margin											
1	Transmission Margin $/M3 / month	0.180895										
2	Contract Demand 10^3m^3/month		1,623	2,762	3,087	3,412	3,737	4,003	4,003	4,003	4,003	4,003
3	Transmission Margin		$3,522	$5,997	$6,701	$7,406	$8,111	$8,690	$8,690	$8,690	$8,690	$8,690
	General Service Transmission Margin = Volumes * Transmission Margin											
4	Transmission Margin $ / M3 consumed	0.022334										
5	Volume 10 ^3 M^3		2,218	6,610	10,912	15,092	19,120	23,000	24,906	24,906	24,906	24,906
6	Transmission Margin		$50	$148	$244	$337	$427	$514	$556	$556	$556	$556
7	Total Transmission Margin		$3,572	$6,144	$6,945	$7,743	$8,538	$9,204	$9,246	$9,246	$9,246	$9,246

The transmissions margins are Jan 2023 rates

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	1	2	3	4	5	6	7	8	9	10
Operating Cash Flow											
Revenue	356,524	3,572	6,144	6,945	7,743	8,538	9,204	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	1,856	(692)	(1,580)	(1,792)	(2,003)	(2,179)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	4,446	4,471	4,383	4,970	5,554	6,043	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	(243,662)	(44,894)	(669)	-	-	-	-	-	-	-
Change in Working Capital	(6)	(6)	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	(243,668)	(44,894)	(669)	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	4,321	8,024	6,902	5,934	5,127	4,451	3,884	3,404	2,997	2,650
Net Present Value											
PV of Operating Cash Flow	89,954	4,321	4,105	3,803	4,074	4,300	4,420	4,198	3,966	3,746	3,539
PV of Capital	(286,677)	(243,668)	(42,413)	(597)	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	4,201	7,368	5,988	4,863	3,969	3,256	2,684	2,222	1,848	1,544
Total NPV by Year	(149,927)	(235,146)	(30,939)	9,194	8,937	8,269	7,676	6,881	6,188	5,594	5,083

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	11	12	13	14	15	16	17	18	19	20
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	2,353	2,097	1,876	1,683	1,514	1,367	1,236	1,121	1,018	927
Net Present Value											
PV of Operating Cash Flow	89,954	3,343	3,158	2,983	2,819	2,663	2,516	2,376	2,245	2,121	2,004
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	1,295	1,090	921	781	664	566	484	414	355	306
Total NPV by Year	(149,927)	4,638	4,249	3,905	3,599	3,327	3,082	2,860	2,659	2,476	2,309

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	21	22	23	24	25	26	27	28	29	30
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	845	771	705	645	591	542	497	457	420	386
Net Present Value											
PV of Operating Cash Flow	89,954	1,893	1,788	1,689	1,596	1,507	1,424	1,345	1,271	1,201	1,134
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	263	227	196	170	147	127	110	96	83	72
Total NPV by Year	(149,927)	2,156	2,015	1,885	1,765	1,654	1,551	1,456	1,367	1,284	1,206

Project NPV	**(149,927)**
Project PI	**0.48**

Panhandle Regional Expansion Project
DCF Analysis
InService Date: Nov-01-2024

Project Year ($000's)	Project Total	31	32	33	34	35	36	37	38	39	40
Operating Cash Flow											
Revenue	356,524	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246	9,246
Expenses:											
O & M Expense	(5,060)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)	(127)
Municipal Tax	(34,200)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)	(855)
Income Tax	(80,857)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)	(2,190)
Net Operating Cash Flow	(120,117)	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075	6,075
Capital											
Incremental Capital	(289,224)	-	-	-	-	-	-	-	-	-	-
Change in Working Capital	(6)	-	-	-	-	-	-	-	-	-	-
Total Capital	(289,230)	-	-	-	-	-	-	-	-	-	-
CCA Tax Shield											
CCA Tax Shield	71,580	355	327	301	277	255	235	217	200	185	481
Net Present Value											
PV of Operating Cash Flow	89,954	1,072	1,012	956	903	853	806	762	720	680	642
PV of Capital	(286,677)	-	-	-	-	-	-	-	-	-	-
PV of CCA Tax Shield	46,796	63	54	47	41	36	31	27	24	21	142
Total NPV by Year	(149,927)	1,134	1,067	1,004	945	889	838	789	743	700	784

Project NPV	**(149,927)**
Project PI	**0.48**

Stage 2 (Customer Fuel Savings) Data for Panhandle Regional Expansion Project

Assumptions

(a)	(b)	(c)	(d)=(b)-(c)
Fuel Prices	$/m^3	Gas $/m^3	Diff $/m^3
Heating Oil	1.90	0.30	1.60
Propane	1.14	0.30	0.84
Electricity	1.08	0.30	0.78

Fuel Mix in the Event Gas is Not Available

	(e)	(f)=(d)*(e)
	General Service	
	Fuel Mix	Wt Ave Diff $/ M^3
Heating Oil	24%	0.382
Propane	10%	0.080
Electricity	67%	0.520
Total %	100%	
Weighted Savings $/m^3		0.982

Gas and alternative fuel prices are the average posted prices for the 12 month period ending March 2023

Prices in the above table are before the added cost of Carbon.

Carbon Prices The cost of carbon is added to the price of each fuel in above table

	2024	2025	2026	2027	2028	2029	2030
Cost per tonne	$80	$95	$110	$125	$140	$155	$170

	Future Yrs 2031 and beyond
Cost per tonne	$0

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings

Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings

For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	226	353

NPV Fuel Savings Range from $226 Mil over 20 yrs to $353 Mil over 40 yrs

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:

Exhibit E, Tab 1, Schedule 5

Question:

(a) Please provide the DCF analysis in a live excel format.
(b) Please re-calculate the project NPV and PI based on there being zero revenue attributable to the expansion project (i) from 2035 onward, (ii) from 2040 onward, and (iii) from 2050 onward. We are not asking Enbridge to opine on these figures as if they are likely scenarios.
(c) If the project is built but demand does not increase above the current capacity of 713 TJ/d, does Enbridge agree that there would be no incremental revenue attributable to the project? If Enbridge disagrees, please explain.
(d) If the project is built, demand initially increases beyond 713 TJ/d, but then declines to below 713 TJ/d from 2035 onward, does Enbridge agree that there would be no incremental revenue attributable to the project from 2035? If Enbridge disagrees, please explain.
(e) In light of federal decarbonization mandates, what is the probability that the design day demand of the panhandle system is at or below 713 TJ/d in (i) 2035, (ii) 2040, or (iii) 2050. Please provide an answer on a best estimate basis.

Response

a) Please see Attachment 1.

b) See Table 1 below. /U

Table 1: Project NPV and PI Based on Zero Revenue from 2035, 2040, and 2050 Onwards

Scenario		NPV ($million)	PI
i	2035 onward	(202)	0.30
ii	2040 onward	(186)	0.35
iii	2050 onward	(165)	0.43

c) and d)
Enbridge Gas agrees that incremental revenue is tied to incremental demands.

However, as set out in Exhibit B, Tab 1, Schedule 1, the needs for the Project were determined by demands reported by customers through the EOI process. As such, the Company has no basis to expect system demands will decline in the manner suggested by ED.

e) ED’s question seeks to have the Company create new evidence based on hypothetical scenarios that would see demand for natural gas decline significantly from current levels. It is not reasonably possible to produce the forecast sought by ED with any certainty as it is unclear how and when the Federal Guidelines will be implemented in Ontario, and what the rate of adoption and/or conversion to alternative energy sources will ultimately be.

Not only does Enbridge Gas not routinely produce forecasts for the durations sought by ED (in part due to escalating forecast uncertainty that is increasingly inherent in longer term forecasts), but it is not practically possible for the Company to completely re-assess the hydraulic models, demand forecasting methodology, engineering design principles, and other factors that currently guide its assessment of projects as part of a response to interrogatories in the current proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe (PP)

INTERROGATORY

Question(s):

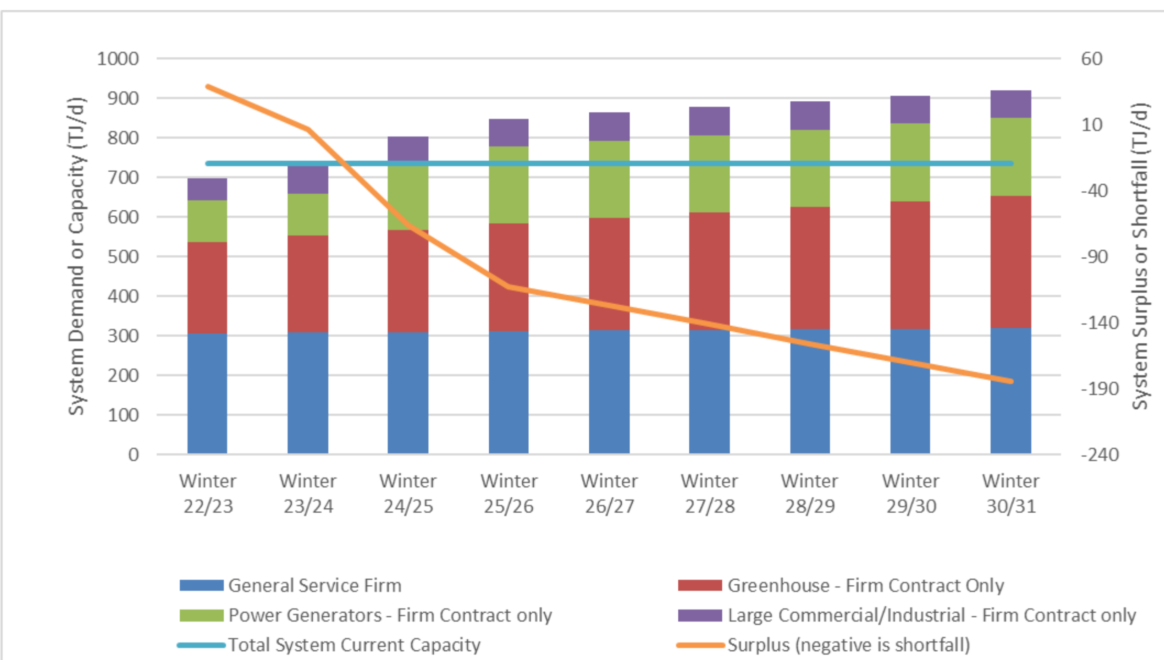
Please replicate Figure 3: Graph of the Forecast Panhandle System Capacity, Design Day Demand and Shortfall [B/2/1 Page 12] and segment the bars in the chart by the following categories:

• General Service
• Large Industrial/Commercial
• Greenhouse Market
• Power Generation

Response:

Please see Figure 1 below.

Figure 1: Graph of the Forecast Panhandle System Capacity, Design Day Demand (by Customer Type) and Shortfall



ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence (“ED”)

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1

Question:

(a) Please reproduce table 1 on page 11 of Ex. B, Tab 1, Schedule 1, adding rows showing:
   i. A breakdown of the demand based on customer classes (residential, commercial, and industrial); and
   ii. A breakdown of demand for forecast years based on that from new versus existing customers.

Please also add three columns to the left with three additional years of historical figures.

Response

a)

i. Below is the summary of demand breakdown by the customer classes indicated (residential, commercial, and industrial) using best available information. /U

ii. There is no forecast demand change for existing general service customers.

	Historical Actuals (TJ/d)						FORECAST (TJ/d)								
	Winter 16/17	Winter 17/18	Winter 18/19	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 System Demand)	298	291	298	317	308	310	306	308	310	312	314	315	317	319	320
Residential Demand (M1)	158	157	163	171	166	167	171	164	165	167	169	169	170	170	169
Commercial/Industrial (estimated M1/M2)	140	134	135	146	142	143	135	144	145	145	145	146	147	149	151
Contract Firm (Total System Demand)	259	321	326	323	348	362	392	422	492	537	550	562	575	588	601
Total System Demand Forecast	**557**	**612**	**624**	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**

ENBRIDGE GAS INC.

Undertaking Response to ED

To restate the table at ED 3, page 2, showing greenhouses broken out from the contract firm

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Response:

Table 1 below reflects Table 2 from Exhibit B, Tab 1, Schedule 1 with Greenhouses broken out on a best effort basis.

Table 1: 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	317	308	310	306	308	310	312	314	315	317	319	320
Greenhouse - Firm Contract Only	159	179	203	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	105	106	106	106	106	163	195	195	195	195	195	195
Large Commercial/Industrial - Firm Contract only	59	62	52	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total System Demand Forecast	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
General Service Firm	19	-9	2	-4	2	2	2	2	2	2	2	1
Greenhouse - Firm Contract Only	28	20	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	-22	1	0	-1	0	57	32	0	0	0	0	0
Large Commercial/Industrial - Firm Contract only	-3	3	-10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Incremental Demand Forecast	**21**	**16**	**16**	**26**	**32**	**72**	**47**	**15**	**14**	**14**	**14**	**14**
Total Incremental Demand Forecast (Cumulative)				**26**	**58**	**130**	**177**	**192**	**206**	**220**	**235**	**249**

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[E-1-1, p.1] Enbridge states that: “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”.

Question(s):

a. How many contractors responded to the RFP and what was each of their bids?

b. Is the contract work being undertaken as part of Enbridge’s ‘Alliance Partners’ contracts?

c. Please explain the structure of the contracts and the specific details regarding allocation of cost risk.

Response:

a. Enbridge Gas invited 7 proponents to bid and received 6 responses. Enbridge Gas invites proponents to present their technical, commercial, and socio-economic offerings in their proposal. Proposals are evaluated against pre-established evaluation criteria to determine a fair and lawful evaluation outcome that may result in the awarding to one or more proponents. Proposals are complex and the evaluation of proposals requires assessment of many factors, including but not limited to technical, health and safety, environmental matters – in addition to bid price. As such, bid amounts would not be valuable information.

   The average proposal price from the top three (3) most competitive proponents was used for the current estimate. The contract has not yet been executed for the Project.

b. No. To ensure a competitive bidding process Enbridge Gas included proponents that are not master agreement holders therefore existing master agreements (such as the Alliance contracts) were not used.

c. The contract has not yet been executed for the Project and therefore finalized details regarding allocation of cost risk are not available. Alternative contract structures including lump sum and unit price were requested as part of the RFP process.

   Enbridge Gas considers lump sum and unit price contract structures to manage the risk of cost overages on construction projects. These contract structures incentivize construction contractor(s) to manage their resources efficiently by allocating the risk of cost overruns due to inefficient use of resources to the construction contractor(s). Other cost risks that are external to Enbridge Gas and the construction contractor(s), such as severe weather conditions, are shared between Enbridge Gas and the construction contractor(s).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

E-1-2

Question(s):

With respect to the updated project costs and scope:

a. Please provide a table that shows, broken down by category, a comparison of projects costs in the original and updated application, limited to the project scope included in the updated application.

b. Please provide a detailed explanation of costs increased, by category, including in part (a).

Response:

a) Please see Table 1 below:

Table 1: Project Costs Comparison

		19km of NPS 36 Pipeline and Ancillary Facilities (Amended Application, June 2023)	19km of NPS 36 Pipeline and Ancillary Facilities (Initial Application, June 2022)
Item No.	**Cost Description**	**Project Costs ($)**	**Project Costs ($)**
1	Materials	57,000,000	56,600,000
2	Labour, External Permitting and Land, and Outside Services	199,300,000	124,100,000
3	Contingency	20,800,000	19,200,000
4	Interest During Construction	12,100,000	3,500,000
5	Total Direct Capital Cost	289,200,000	203,400,000
6	Indirect Overheads	68,800,000	43,200,000
7	Total Project Cost	358,000,000	246,600,000

b) Enbridge Gas attributes the variances to the following three causes: a) bid to estimate variance; b) unforeseen inflation; and c) scope refinement. Consistent with the proposed Project, Enbridge Gas has experienced inflationary pressures on all projects within the capital portfolio.

Please see the information below for details regarding the items in Table 1 with increased costs compared to the initial application.

Labour, External Permitting and Land, and Outside Services

The Project costs in the initial application were developed using 2021 Construction Contractor Request for Information (“RFI”) responses. The amended application relies on Contract Request for Proposal (“RFP”) responses for Q4 2022.

Increased cost estimates between the RFI and the RFP were driven primarily by inflationary pressures and, to a lesser extent, refinements in engineering design.

The Q4 2022 RFP amounts reflect inflationary increases in prime contractor costs including equipment rental rates, fuel prices, and labour rates. The prices for materials and labour had significantly increased since 2021, and these increases are believed to be driven by supply chain challenges that have arisen in recent years.

Other drivers for the cost estimate increase are related to scope refinements identified during the detailed design stage. As part of standard project development activities, further refinement was carried out on the Project design. The results of the refinements to engineering design included but are not limited to additional materials (e.g., valves, actuators, and cabling), additional trenchless crossings and added depth to open cuts, and increased inspection hours. This was offset in part by review of the design resulting in a streamlined design of the stations scope to realize cost reductions.

As discussed at the response to Exhibit I.SEC.1, the contract has not yet been executed. Enbridge Gas invited 7 proponents to bid and received 6 responses to the Q4 2022 RFP for prime contractor. The average proposal price from the top three (3) most competitive proponents was used for the current estimate.

Enbridge Gas continues to be proactive to reduce the impact of the higher cost estimate, and this includes a rigorous negotiation of contracts to select lower cost bids with the required technical expertise.

Interest During Construction

The primary drivers are increased interest rates and the increased capital cost of the Project.

Indirect Overheads

Indirect overheads are a function of the total capital cost and the overhead rate for the in-service year. The increase to indirect overheads is a function of the increase in direct capital spend and a revision to the rate applied due to the shift in timing of the Project (23.8% vs. 21.2%).

ENBRIDGE GAS INC.

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[Cover Letter, June 16, 2023] With respect to the Leamington Interconnect, Enbridge states: "Following Enbridge Gas's re-assessment of the Project in 2022 and 2023, the Company has elected to remove the Leamington Interconnect from the scope of the proposed Project and will reassess its need in the future should projected system shortfalls come to fruition and warrant its reconsideration."

Question(s):

a. Please provide a detailed explanation of why Enbridge chose to remove the Leamington Interconnect from the scope of the proposed project.

b. Please confirm that based on the Capital Update filed in EB-2022-0200, the Leamington Interconnect project is forecast to be completed in 2026 at a cost of $118.8M (see EB-2022-0200, 2.6-CCC-71, Attach 1, p.6 (2023-07-06).

c. Please reconcile part (b) with the statement that Enbridge will reassess its need in the future.

d. Please provide a revised DCF Analysis (E-1-5) that includes the cost of the Leamington Interconnect based on the costs forecast in the Capital Update of the EB-2022-0200 application. Please provide all supporting calculations and the DCF Analysis in Excel format.

Response:

a) Enbridge Gas's Alternatives Assessment Criteria for the Project includes a "timing" criterion whereby "the alternative must meet the growing firm demands on the Panhandle System for the next five years".[1] At the time of the filing of Enbridge Gas's initial application and evidence (i.e., June 2022) the Company projected that the Leamington Interconnect would be required to meet a system shortfall in Winter 2025/2026 (following construction of the Panhandle Loop) - within the 5-year

[1] Exhibit C, Tab 1, Schedule 1, p. 3.

timeframe mentioned above. As a result, the Leamington Interconnect was included within the initial application and evidence.

In 2023, following receipt of the new cost information, the Company re-assessed the capacity position of the Panhandle System based on actual 2022 attachments and their system locations, as well as updated 2023 customer demand. These updates are described at Exhibit A, Tab 4, Schedule 1. The combined effects of these updates indicated that a further system shortfall (following construction of the Panhandle Loop) is not expected to occur until Winter 2029/2030 – beyond of the 5-year timeframe mentioned above. As a result, Enbridge Gas elected to remove the Leamington Interconnect from the scope of the Project.

b) Confirmed.

c) Enbridge Gas's best available information at this time reflects a system capacity shortfall as early as November 1, 2029. Alternatives including the Leamington Interconnect and/or other potential solutions will be assessed in the future. As with all growth projects included in the AMP, Enbridge Gas will continue to reassess/update their need.

d) Enbridge Gas respectfully declines to provide the requested analysis, which is based on a Project scope (i.e., inclusion of the Leamington Interconnect) that the Company's is not seeking approval of. As per the response to part a) above, Enbridge Gas has removed the Leamington Interconnect from the Project's scope and will reassess its need in the future.

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
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[A-4-1, p.5-6] Enbridge states: "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."

Question(s):

a. Please provide a copy of all correspondence and any notes of discussions between Enbridge and customers regarding the potential requirements for a CIAC payment.

b. Please provide a copy of all instructions and/or guidance provided to Enbridge Account managers regarding the OEB's comments in Procedural Order No. 4.

Response:

a) Please see the response at Exhibit.STAFF.25, part a).

b) Please see Attachment 1 to this response for a Q&A reference sheet provided to Enbridge Gas account managers regarding the 2023 EOI/ROS process which included information regarding CIAC.

   Please see Attachment 2 to this response for an e-mail (dated February 22, 2023) sent to Enbridge Gas account managers regarding the 2023 EOI/ROS process which included information regarding CIAC.

Panhandle Regional Expansion Project

Q&A for EOI / Binding Reverse Open Season 2.0

Q: Why is Enbridge Gas again going out with another Expression of Interest and Reverse Open Season for the Panhandle Regional Expansion Project?

Enbridge Gas filed a leave-to-construct application with the Ontario Energy Board in June 2022 for two new proposed transmission facilities and ancillary facilities (19 km of 36-inch looping “Panhandle Loop” and 12 km of new 16-inch pipe connecting the connect the existing Leamington North Lines to both the Kingsville East Line and the Leamington North Reinforcement Line “Leamington Interconnect”). Through the course of the regulatory process, new cost information became available which resulted in Enbridge requesting the LTC application be place in abeyance (on hold).

From Enbridge’s letter to the OEB dated December 5, 2022 (request to place project in abeyance):

Very recently, Enbridge Gas received new cost information through a competitive procurement process that it has been undertaking in parallel with the application, in anticipation of the future construction of the proposed Project. Based on that new information, Enbridge Gas has identified potentially material increases to certain components of the estimated Project cost. Enbridge Gas is in the process of assessing this new cost information and its implications for the application and the evidence that is currently before the OEB.

From Enbridge’s letter to the OEB dated February 1, 2023 (request for extended abeyance until no later than August 2023):

Following the receipt of the new cost information, Enbridge Gas re-assessed 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 now anticipates that incremental demand for Winter 2023/2024 can be accommodated and that the Project’s in-service date can be deferred one year from November 1, 2023, to November 1, 2024.

The Company continues to assess the Project cost information, the capacity position of the Panhandle System, and future customer demand. Enbridge Gas expects to complete and file evidence amendments incorporating the Company’s assessment of these aspects as soon as possible and no later than August 2023 and is requesting that the OEB continue to hold the application in abeyance until that time.

Given the time between the request for continued abeyance and when we expect to file the updated LTC application, Enbridge Gas is conducting this second EOI and Binding Reverse Open season to reconfirm market demands and timing. We are also trying to address some of the issues raised by intervenors and OEB staff during the regulatory process (energy transition & conservation, education of alternatives to firm service i.e. reduced IT rates, DSM opportunities, and the potential for contributions-in-aid-of-construction or "CIAC" for transmission assets).

Q: Do I have to submit a bid in this EOI if I previously submitted a bid in the 2021 EOI?

Customers who participated in Enbridge Gas' 2021 Non-Binding Expression of Interest should submit a new bid form as part of this Expression of Interest for the full amount of additional capacity required in 2024 and beyond. Unless Enbridge Gas receives a new bid form, the company will assume that no new capacity is required.

Customers who have already executed a distribution contract with Enbridge Gas do not have to resubmit a an EOI bid form unless they have new or incremental requirements beyond what has already been contracted for.

Q: Are contributions-in-aid-of-construction (CIACs) required by Enbridge Gas for customers taking new/incremental firm service from the proposed transmission facilities?

Enbridge Gas' position is that customers should not be required to pay a CIAC to improve the economics of the proposed transmission project. Customers may be required to pay a CIAC in addition to executing a long-term distribution contract for any customer-specific distribution facilities (station, service, and/or localized distribution reinforcement required with/without a HAF being utilized).

This was the response provided by Enbridge for undertaking JT1.3 on the issue of CIACs for transmission assets.

Undertaking response for JT1.3

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).

[1] Exhibit B, Tab 1, Schedule 1, p. 5, Figure 1

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]

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]

Q: Why is the EOI non-binding and the Reverse Open Season binding?

The purpose of the EOI is to gather information on customer growth plans for the next 5-10 years and will be used as an input to the demand forecast as well as the validation of the proposed transmission facilities and/or potential alternatives. In order to capture total market potential, the EOI is non-binding, meaning customers are not committing to the capacity at this time.

[2] EB-2018-0013, OEB Decision and Order (September 20, 2018), pp. 5-6
[3] EB-2020-0094, OEB Decision and Order (November 5, 2020), p. 20

Customers expressing interest in new/incremental firm capacity, and who wish to secure that capacity as part of the project, will need to execute a distribution contract or Letter of Indemnity to formally commit to the capacity they are requesting. Capacity will be available on a first-come first-serve basis.

The reverse open season is binding, meaning if a customer elects to turnback firm or interruptible capacity, or convert existing firm service to interruptible service, and if Enbridge accepts the bid with or without conditions attached, the customer will be required to proceed with the turnback request (a contract amendment would be processed to reflect the reduced contract parameters). If a customer exceeds their revised contract parameters after turnback, or wishes to increase contract parameters in the future, the request will be subject to available system capacity at the time the request is received. There is no guarantee that the capacity will be available for them in the future without new facilities and/or alternatives.

Any capacity turned back by customers through the Binding Reverse Open Season will be used to minimize any facilities and/or alternatives deemed to be required to serve incremental demand. Enbridge Gas reserves the right to reject any and all bids received.

Q: Which customers are being included in the EOI / Reverse Open Season?

The EOI & ROS is being sent to all distribution contract customers in the area of benefit for the proposed project (western Chatham-Kent and all of Windsor/Essex County). The email will be sent to all of the signing and alternate signing authorities attached to each distribution contract in the AOB. Account managers are encouraged to forward the email to any other relevant contacts for each account, as well as to any customers not currently in the AOB, but who may have future growth plans inside the AOB). Marketers in the LUG South rate zone representing customers in the AOB will also be included in the distribution list.

Q: What is the new proposed in-service date for the proposed project?

The revised in-service date for the proposed project is November 2024. Customers can request capacity earlier than November 2024 which may be available on a best-efforts basis or through the use of an interim IT bridging solution (for those requesting new/incremental firm service).

From: Matt Ciupka <Matt.Ciupka@enbridge.com>
Sent: Wednesday, February 22, 2023 4:33 PM
To: In-Franchise Sales – Key Accounts <In-FranchiseSales_KeyAccounts@enbridge.com>; In-Franchise Sales - LCI Accounts <In-FranchiseSales_LCIAccounts@enbridge.com>; In-Franchise Sales – Strategic Accounts <In-FranchiseSales_StrategicAccounts@enbridge.com>
Cc: Ian Macpherson <Ian.Macpherson@enbridge.com>; Paolo Mastronardi <Paolo.Mastronardi@enbridge.com>; Todd Marentette <Todd.Marentette@enbridge.com>; Mark Prociw <Mark.Prociw@enbridge.com>
Subject: INFORM: PREP Expression of Interest and Binding Reverse Open Season - 2023

Good Afternoon,

Tomorrow we will be launching the Expression of Interest (EOI) and Binding Reverse Open Season (ROS) for the Panhandle market area!

Once Web Publishing confirms the websites updates are live, a notification email will be sent from the ***Enbridge Gas Large Volume Customer Communications*** mailbox to all existing contract rate customers in the defined Area of Benefit. This should occur between 10am and noon tomorrow.

- The email will be sent to the Signing Authority and Signing Authority Alternates currently attached to each SA – please feel free to forward the email to any of your contacts if the Signing or Alt Signing Authority isn't your main contact. You are also encouraged to forward the email to any customers that are not in the area of benefit but considering the area for growth, or existing general service customers who may be expanding and would qualify for contract rate service.

- A copy of the EOI/ROS package, along with a listing of the customers that will receive the email, and a Q&A document have been uploaded to the new **DIFS PREP Team** channel in Teams.

- A tracking file to document the outreach progress and record information gained from customer discussions is also located on the **DIFS PREP Team** channel. **<u>Please update the tracking file every time you've had a discussion with a customer</u>**. You'll note that there is a column to record customer responses to the CIAC for transmission assets question. Please refer to the Q&A document for background on the question and EGI's current position on it –

and don't hesitate to reach out if you want more background or information on why we are asking this when speaking to customers.

- Weekly touchpoints have been set up for those who have accounts in the area to discuss outreach progress, customer feedback received, general observations and Q&A. Please feel free to add questions to the Q&A document and we will add on to it as new questions come up. If you haven't been included on the invite list but would like to attend the touchpoints please let me know and I'll add you.

- A copy of the EOI & ROS documents can also be found on the **Indmarketing** drive under **\Contract Sales Team\02 – PREP EOI ROS 2023**. We want to leverage the DIFS PREP Team channel as much as we can.

- The EOI BROS will remain open for 30 business days and will be **closing on Thursday April 6th, 2023 at 12 pm ET**. EOI and/or ROS bid forms must be submitted by customers to the Economic.Development@Enbridge.com on or before that date. If you receive any bid forms directly from customers, please forward them to the Economic.Development@Enbridge.com mailbox for control and tracking purposes.

Please do not hesitate to reach out at any time if you have questions, concerns, comments or are seeking advice – remember, there are no dumb questions!

I'm looking forward to the journey ahead and wish you all the best in your customer outreach efforts.

Thanks,
Matt

Matt Ciupka, **MBA (he/him)**
Specialist, Economic Development
Strategic & Power Markets

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Safety. Integrity. Respect. Inclusion.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

INTERROGATORY

Reference:

Updated Application, Exhibit B, Tab 1, Schedule 1, page 7, paragraph 26, page 10, paragraph 33; Attachment 8: 2023 Expression of Interest Non-Binding Bid Form, Attachment 9: 2023 Distribution Service Binding Reverse Open Season Form

Preamble:

After the proceeding was placed in abeyance on December 5, 2022, Enbridge Gas updated its forecast of the demand for incremental capacity to support the need for the Project. To re-confirm the customer interest in demand for incremental capacity on the Panhandle System Enbridge Gas launched, on February 23, 2023, the second non-binding Expression of Interest (EOI 2023) and a Binding Reverse Open Season (ROS). A total of 42 EOI 2023 bids were received from 39 entities as of closing the EOI process on April 6, 2023. The prospective customers expressed interest for capacity of 197 TJ/d from 2024 to 2033. Of the 42 bids, 38 were from the greenhouse sector, 2 from the electricity generation (power) sector and 2 from commercial sector.

According to the outcomes of the EOI 2023, 94% of the total incremental potential project demand is by contract rate customers. Enbridge Gas stated that, as of May 2023, 34% of the contract rate customer demand is “underpinned by firm distribution contract”.

Enbridge Gas plans to execute distribution service contracts with customers for the service in 2024 and 2025 and secure the remaining contracts from contract rate customers in the years to follow.

Question(s):

a) Please explain the statement that 34% of the contract customer demand is underpinned by firm distribution contracts. How many firm distribution contracts have been executed to date for incremental firm service in 2024 and 2025? Please provide a total contracted capacity demand for 2024 to 2025 by volume, by customer or by sector.

b) What is Enbridge Gas’s plan to secure the remaining firm distribution contracts for the incremental capacity demand forecast for the years 2026 to 2033?

Response

a) 57 TJ/d of incremental customer demand is currently underpinned by a firm distribution contract, accounting for 34% of the total incremental capacity created by the Project (i.e., 168 TJ/d).

In addition, Enbridge Gas is actively engaged in contract negotiations with customers who require an additional 10 TJ/d of incremental capacity starting in 2024 and 64 TJ/d of incremental capacity starting in 2025.

The total amount of incremental customer demand that is currently underpinned by a firm distribution contract or is being negotiated for a firm distribution contract by the end of 2025 (i.e., the first 2 years of the Project) is 131 TJ/d, accounting for 78% of the total incremental capacity created by the Project (i.e., 168 TJ/d).

Please see Table 1 below for a breakdown of incremental customer demand requirements (underpinned by a firm distribution contract and in negotiation) for 2024 and 2025 by customer and sector.

Table 1: 2024 and 2025 Incremental Customer Demand Requirements (Underpinned by Firm Distribution Contract and In Negotiation) by Customer and Sector

Status	Customer	Sector	TJ/Day		
			2024	2025	Total
Underpinned by Firm Distribution Contract					
	1	Power[1]	57.4	0	57.4
Total Underpinned by Firm Distribution Contract			**57.4**	**0**	**57.4**
In Negotiation					
	2	Power	0	6.3	6.3
	3	Power	0	25.1	25.1
	4	Greenhouse	0.5	3.1	3.6
	5	Greenhouse	2.4	0	2.4
	6	Greenhouse	0	2.4	2.4
	7	Greenhouse	2.2	0	2.2
	8	Greenhouse	0	2.1	2.1
	9	Greenhouse	1.6	0	1.6
	10	Greenhouse	0	1.4	1.4
	11	Greenhouse	1.3	1.6	2.9

[1] The contract term for the executed contract is July 16, 2024 to July 15, 2029.

	12	Greenhouse	1.3	1.3	2.7
	13	Greenhouse	0	1	1
	14	Greenhouse	0	0.9	0.9
	15	Greenhouse	0.4	0	0.4
	16	Greenhouse	0.2	0	0.2
	17	Greenhouse	0	4.5	4.5
	18	Greenhouse	0	3.1	3.1
	19	Greenhouse	0	2.2	2.2
	20	Greenhouse	0	1.6	1.6
	21	Greenhouse	0	1.3	1.3
	22	Food and Beverage	0	0.1	0.1
	23	Greenhouse	0	0.9	0.9
	24	Greenhouse	0	1.1	1.1
	25	Greenhouse	0	1.7	1.7
	26	Greenhouse	0	0.8	0.8
	27	Greenhouse	0	1.3	1.3
Total In Negotiation			**9.9**	**63.8**	**73.8**
Total Underpinned by Firm Distribution Contract and In Negotiation			**67.3**	**63.8**	**131.2**

b) Enbridge Gas is primarily engaged in discussions and negotiations with contract customers requiring capacity in the near term (i.e., 2024 - 2025) to execute firm distribution contracts. For bids received requesting service beyond 2025, Enbridge Gas will be engaging with those customers over the next 12-24 months, or otherwise as appropriate, to initiate activities which include the assessment of customer specific distribution assets, establishment of credit, and ultimately contract execution.

It should be noted that Enbridge Gas is also engaged in active discussions and negotiations with customers who did not submit EOI bids but required additional capacity, including companies seeking to locate in Windsor, Essex County, and Chatham-Kent to support new technologies such as electric vehicle battery manufacturing related industries.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

INTERROGATORY

Reference:

Procedural Order No. 4, December 14, 2022, page 3; Updated Application Exhibit E, Tab 1, Schedule 1, B. Project Economics, paragraph 4, page 3

Preamble:
In Procedural Order No. 4, which placed the proceeding in abeyance as of December 5, 2022, the OEB confirmed that the issue of the applicability of E.B.O. 134 and E.B.O. 188 is within the scope of the proceeding. The OEB stated:

"...the OEB is of the view that the economics of the project, the applicability of EBO 134 and EBO 188, and the extent to which contributions in aid of construction should be required are issues that are in scope for this proceeding. Enbridge may wish to consider whether to provide additional evidence on those issues as part of its proposed update to its application. Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."

In the updated application filed on June 16, 2023, Enbridge Gas addressed the issue of applicability of the E.B.O. 134 and E.B.O. 188 by stating that E.B.O. 134 is the appropriate economic test as the Project is entirely a transmission project.

As part of the EOI 2023, Enbridge Gas conducted outreach to customers who indicated their intention to submit an EOI bid to obtain customer's position on paying CIAC. Enbridge Gas asked these customers how a requirement for a CIAC may impact their demands for new/incremental service.

Enbridge Gas stated that the customers feedback was as follows:

• 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.

Question(s):

a) Please provide details on Enbridge Gas's customer outreach activities regarding the requirement for a CIAC including dates, method of communication, and information provided to customers.

b) Please advise whether any customers will be directly connected to the Project.

c) Please advise whether Enbridge Gas agrees that the Project almost entirely benefits identifiable contract customers.

Response:

a) As part of the 2023 EOI, Enbridge Gas conducted outreach to customers who indicated their intention to submit an EOI bid to obtain their position on paying a CIAC. Enbridge Gas asked these customers how a requirement for a CIAC may impact their demands for new/incremental service. This outreach was a result of the OEB's Procedural Order No. 4 dated December 14, 2022, which stated:[1]

> "Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."

Outreach occurred between February 15, 2023 and April 6, 2023.

There was no information sent to customers regarding the matter, and Enbridge Gas account managers were not provided with a script to deliver to customers. Rather, Enbridge Gas account managers sought customer feedback via verbal communication and recorded any feedback from customers. The customer feedback collected by Enbridge Gas account managers can be found at Attachment 1 to this response. Please note that Enbridge Gas is requesting confidential treatment of the names of customers in Attachment 1. A summary of the feedback back can be found at Exhibit A, Tab 4, Schedule 1, Paragraph 21.

Please also see the response at Exhibit I.SEC.5, part b) for instructions/guidance provided to Enbridge Gas account managers regarding the matter.

[1] OEB Procedural Order No. 4 (December 14, 2022), p. 3.

b) No customers will be directly connected to the Project.[2]

c) No, Enbridge Gas does not agree that the transmission Project almost entirely benefits identifiable contract customers. The very nature of a transmission pipeline is that it provides natural gas to a broad geographic region comprised of multiple distribution systems of which a large number of both contract and general service customers are served. Whereas distribution pipelines benefit a very specific customer or set of customers, a transmission pipeline provides benefits to a broad region. The proposed Project will enable the transportation of natural gas for the benefit of all natural gas customers within the Panhandle Market (including the Municipalities of Chatham-Kent, Lakeshore, Tecumseh, Windsor, LaSalle, Amherstburg, Essex, Kingsville and Leamington, St. Clair, and Dawn-Euphemia).

   The proposed Project partially alleviates the largest Panhandle System bottleneck (see Exhibit B, Tab 2, Schedule 1, pp. 13 - 14). Partial alleviation of the bottleneck improves the reliability of natural gas service for existing customers and will allow for growth among both existing and new customers on the Panhandle System. All customers benefit from alleviation of Panhandle System bottlenecks.

   Although the demand forecast is based on contract customers who responded to the EOI, these are not the only customers that will benefit from the capacity created. Customers that did not respond to the EOI will have the ability to connect to the system using any capacity that is available at the time of their request. The timing of when commercial, industrial, and power generation customers are in a position to express their needs for natural gas service do not always align with the timing of Enbridge Gas's EOI process. As a result, the EOI results are only a point-in-time snapshot of customer demand. As has been demonstrated over the last decade, both expected and unexpected growth in the Panhandle Market area has continued to materialize as new customers attach to the natural gas system. As these new customers request natural gas service, it is important that Enbridge Gas has the ability to accommodate them in a timely and economic manner.

   Transmission system capacity is available on a "first come, first served" basis. Once in service, the proposed Project will serve all existing and future customers whether or not they participated in the EOI.

   The capacity created by the proposed Project will also benefit new general service customers. The timing for the attachment of general service customers is dependent upon the planning and development of new residential and commercial buildings as undertaken by cities, municipalities, and developers. Since the Project will provide

[2] For clarity, the Project consists of the Panhandle Loop (i.e., 19 km of NPS 36 natural gas pipeline) and ancillary measurement, pressure regulation, and station facilities within the Township of Dawn Euphemia and in the Municipality of Chatham-Kent.

incremental capacity across a broad geographic region, it will benefit all new general service customers in that area by allowing Enbridge Gas to attach these new customers as they emerge.

Existing contract and general service customers will also benefit from the capacity created by the Project. These customers, which are already attached to the system, will have the ability to grow their natural gas use (and in some cases their businesses) by leveraging the capacity that is available after the Project is placed into service.

From an operational standpoint, the proposed Project also provides enhanced system reliability and redundancy to existing customers during non-peak times of the year. Once the proposed pipeline facilities are placed into service, they become a functional loop of the overall Panhandle System. Enbridge Gas cannot differentiate natural gas molecules as they flow through the transmission system, and as a result both new and existing customers will be served by both the new and existing transmission facilities. The proposed Project increases operational flexibility in the event of maintenance, in-line inspections or unplanned outage on the Panhandle System, including interruption of Ojibway supply.

From a broader economic perspective, as outlined at Exhibit E, Tab 1, Schedule 1, Paragraph 19, the transmission Project will also provide direct and indirect economic benefits to Ontario estimated at approximately $257 million. This figure does not include the similar direct and indirect economic benefits to Ontario when both existing and new natural gas customers invest and grow their operations. Within EOI bid responses, customers indicated that total direct capital investments into their business operations in Southern Ontario related to their incremental natural gas needs would exceed $4.5 billion.

Enbridge Gas is aware of an increased demand for natural gas in the Panhandle Market via local economic development organizations and recent publications:

- March 2023: “Drawings, details of new hospital revealed during virtual town hall” – https://windsorstar.com/news/local-news/drawings-details-of-new-hospital-revealed-during-virtual-town-hall
- April 2023: “Windsor-Essex being eyed for billions in new industrial investment” – https://windsorstar.com/news/Windsor-essex-being-eyed-for-billions-in-new-industrial-investment
- June 2023: “New Interchange Connecting Lauzon Parkway To 401 'Highest Priority' Says Ford” – https://www.iheartradio.ca/am800/news/new-interchange-connecting-lauzon-parkway-to-401-highest-priority-says-ford-1.19736147

- July 2023: "Windsor lands another big EV auto supply chain company" – https://windsorstar.com/news/Windsor-lands-another-big-ev-auto-supply-chain-company
- August 2023: "Windsor inching closer to landing another major foreign investment" – https://windsorstar.com/news/Windsor-inching-closer-to-landing-another-major-foreign-investment

Please also see a recent Globe and Mail article which includes commentary from the greenhouse industry:

- August 2023: "Southern Ontario's greenhouse operators warn lack of infrastructure is slowing growth in booming sector" – https://www.theglobeandmail.com/business/article-windsor-greenhouse-growers-infrastructure/

The IESO has similarly recognized the significant and exceptional demand the Panhandle Market area will experience as part of their Southwest Ontario Bulk Planning initiatives[3].

> *"Electricity demand in Southwest Ontario is growing at a rapid pace. This growth is primarily driven by economic development in the agriculture and manufacturing sectors. The Windsor-Essex and Chatham-Kent areas are the primary drivers of the agriculture growth, which is projected to reach a demand of 2,300 MW by 2035 - the equivalent of adding a city the size of Ottawa to the electricity grid."*

The IESO has forecasted that Ontario will see a capacity need emerging in 2025 and growing through the latter part of the decade. Peak electricity demand in the Windsor-Essex and Chatham areas is forecast to grow from roughly 500 megawatts in 2022 to about 2,100 megawatts in 2035, equivalent to adding cities the size of Ottawa and London to the grid. The IESO was directed by the Minister of Energy to procure certain natural gas generation to respond to this demand.

Enbridge Gas understands that replacing the generation capacity that the IESO has been directed by the Minister of Energy to procure will be significantly more expensive to meet the demand and reliability needs of the Panhandle region. Furthermore, it is not clear at this time what other generation technology has the ability to be deployed in the timeframe and scale required to respond to system needs. More specifically:[4]

[3] https://www.ieso.ca/en/Get-Involved/Regional-Planning/Southwest-Ontario/Southwest-Ontario-Bulk-Planning-Initiatives
[4] https://www.ontario.ca/files/2023-07/energy-powering-ontarios-growth-report-en-2023-07-07.pdf, p. 49.

“Ontario’s natural gas generators can be turned on and ramped up quickly to ensure the province does not need to be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid, according to the IESO.

While during most hours throughout the year Ontario can meet its electricity generation needs with nuclear, hydroelectric, bioenergy, wind and solar power, natural gas generation also acts as the province’s insurance policy that can be turned on if the wind is not blowing or sun is not shining, or another generator is offline for repairs. There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature.”

Customer	Comments Heard Regarding Customer Specific CIAC for Transmission Assets
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	No, everything costs too much. Fertalizer up 32% in Jan/Feb, labour up, HR costs up.
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted].	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Need to minimize all business costs
[redacted]	No, don't want to pay as much as they do already
[redacted]	No comment provided
[redacted]	Not in favor of making contribution
[redacted]	No comment provided
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Customer does not want to see any change to current process for CIAC for Distribution
[redacted]	No comment provided
[redacted].	Customer uninterested in paying direct costs
[redacted]	Customer uninterested in paying direct costs
[redacted]	Not in favor of making contribution
[redacted]	No comment provided
[redacted].	No comment provided
[redacted]	No comment provided
[redacted]	Customer uninterested in paying direct costs
[redacted]	Customer uninterested in paying direct costs
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Customer uninterested in paying direct costs
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Not in favor of making contribution
[redacted]	Customer does not want to see any change to current process for CIAC for Distribution
[redacted]	No comment provided
[redacted]	No comment provided
[redacted]	Not interested in paying any direct costs
[redacted]	Not interested in paying any direct costs

ENBRIDGE GAS INC.

Answer to Interrogatory from
Ontario Energy Board Staff (STAFF)

INTERROGATORY

Reference:

Updated Application, Exhibit B, Tab 1, Schedule 1, Attachment 1, Panhandle Regional Expansion Projects-Expression of Interest and Capacity Request Form, February 17, 2021, pages 1-2; Exhibit B, Tab 1, Schedule 1, Attachment 8, Panhandle Regional Expansion Project -Expression of Interest and Reverse Open Season, February 23, 2023, pages 1-7; OEB Decision and Order, December 5, 2020, EB-2020-0094, pages 13-15

Preamble:

The OEB approved, on December 5, 2020, Enbridge Gas's Application for approval of a System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor. In that proceeding Enbridge Gas stated that it intended to use the Hourly Allocation Factor (HAF) process on development projects that may involve a mix of distribution and transmission facilities.

The OEB in its Decision found that the "…use of the HAF results in allocation of the capital costs of a project in a fair and equitable manner as the costs would be allocated over time to eligible customers seeking access to the incremental capacity generated by the project".[1]

Enbridge Gas's Expression of Interest and Capacity Request Form, February 17, 2021 informed the prospective contract customers that the HAF process would be used to charge the prospective contract customers for additional distribution facilities that may be required to serve demands provided by the transmission facilities and that the application of the HAF methodology would be subject to approval of the OEB. There is no mention of the HAF in the EOI 2023 form filed in the updated evidence.

[1] EB-2020-0095 Decision and Order, December 5, 2020, page 16

Question(s):

a) In addition to the Enbridge Gas's HAF process statement in the EOI 2021 form, please discuss Enbridge Gas's view on asking the contract customers that benefit from the Project to contribute to the capital cost of the transmission facilities applying the HAF process.

b) Please advise whether there was any further communication in regard to the HAF with prospective customers following the closing of the EOI process in 2023? If not, please explain why not. If yes, please provide a summary of customers' comments with respect to the application of the HAF.

Response:

a) The statement regarding the Hourly Allocation Factor ("HAF") was included in the 2021 EOI form because Enbridge Gas had not yet determined what facilities were required (i.e., distribution facilities or transmission facilities), and customer demands and their locations were unknown when the EOI was issued. Depending on the results of the 2021 EOI process, transmission and/or distribution facilities may have been required to meet customer demands. The statement within the 2021 EOI regarding the HAF was in relation to potential distribution facilities, not potential transmission facilities.[2]

   The 2023 EOI form did not include a statement regarding the HAF because the 2021 EOI process provided clarity that only transmission facilities were required for the Project.

   Enbridge Gas does not believe it is appropriate to apply the HAF to large volume customers as the Project consists exclusively of transmission facilities and does not include any distribution facilities. The OEB's Decision, which approved the conditions for the use for the HAF, was issued within the context of E.B.O. 188, which relates solely to the economic evaluation of distribution system expansions. The OEB reiterated the applicability of the HAF within its November 5, 2020 Decision regarding EB-2020-0094 (p. 20, emphasis added):

   > *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. <u>For exclusively transmission projects, the OEB has not agreed to the application of HAF</u>.*

[2] For clarity, the statement within the 2021 EOI form regarding the HAF was as follows: "The Hourly Allocation Factor process recently approved by the OEB will be used for any **additional distribution facilities that may be required** related to the demands served by the transmission facilities [emphasis added]." (Exhibit B, Tab 1, Schedule 1, Attachment 1, p. 1).

The HAF works properly for a distribution project since the capacity created by the distribution facilities can be localized to a very specific area where the hydraulic benefits of the project are spread evenly. Due to this localized nature of distribution project, Enbridge Gas can calculate a HAF that applies equally anywhere within that distribution project area of benefit. When a customer reserves capacity within that project's area of benefit, the specific location of that customer does not impact how much of the project capacity is used. In other words, two customers attaching in two different areas of that distribution project area of benefit will have the same impact on the project facilities. This allows Enbridge Gas to calculate a HAF that can be appropriately administered and results in a HAF that is applied equitably amongst customers over time.

Conversely, the use of the HAF is not appropriate for transmission projects due to the broad geographic area impacted by the facilities. The benefits of the transmission project are not spread evenly across that region, which prevents Enbridge Gas from calculating a HAF that is applicable across the entire area of benefit. A customer's location within that geographic area will have a major impact on how much of project capacity is needed to serve that customer, and therefore customers will not benefit equally from the transmission facilities. In other words, two customers attaching in two different areas of a transmission project area of benefit will not have the same impact on the project facilities. If these customers were to pay a HAF, they would not be contributing equally to the project costs. A transmission project serving multiple classes of customers that have varying impacts to project capacity over a multi-year attachment horizon makes the calculation and administration of the HAF complex and inequitable. This leads to significant risks related to the determination of an appropriate allocation between large and small volume customers in Southwestern Ontario.

b) No communication occurred during or after the close of the 2023 EOI regarding the HAF. The Project consists exclusively of a transmission facility (and no distribution facilities) and as such the HAF and/or CIAC are not appropriate. Please see the response to part a) above and Exhibit I.STAFF.25, part c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

EB-2020-0094 (November 5, 2020 Decision and Order on Application by EGI for approval of a System Expansion Surcharge, a Temporary Connection Surcharge and an Hourly Allocation Factor), page 13, 3rd paragraph.

The Area of Benefit is determined by hydraulically modelling the pipeline network in the region around the proposed Development Project to determine the geographic extent of the area that will benefit from the incremental capacity of the project. Exhibit B, Tab 1, Schedule 1, page 3, paragraph 12 and page 4 Figure 1, describing the Area of Benefit for the Project.

Question(s):

Please confirm that the Area of Benefit for PREP complies with the definition of "Area of Benefit" as set out in the referenced excerpt from the OEB's 2020 Decision approving the Hourly Allocation Factor (HAF) mechanism.

If not confirmed, please explain the difference in the two uses of the term.

Response:

Not confirmed. The Area of Benefit shown in Exhibit B, Tab 1, Schedule 1, Figure 1 was developed for the EOI. The purpose of the EOI was to collect information regarding customer interest in natural gas in the area downstream of the existing NPS 20 Panhandle Line bottleneck (see Exhibit B, Tab 2, Schedule 1, pp. 13-14 for more information regarding Panhandle System bottlenecks). Please note that all capacity along the Panhandle Transmission System can be used to serve any customer from Dawn to the Ojibway valve site in Windsor, and that Project benefits extend beyond EOI-identified customers (please see the response to Exhibit I.STAFF.25, part c)).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, page 7, paragraph 26.

The evidence indicates that;
a. In response to the 2023 Expression of Interest Process (EOI) EGI received 42 bids for capacity for the Project from 39 entities totalling 197 TJ/day of interest.

b. This 197 TJ/day is incremental to capacity already contracted by customers via the 2021 EOI and in the normal course of business since the close of that process.

Question(s):

(a) Please indicate how many of the 39 entities who responded to the 2023 EOI are customers whose forecast hourly gas consumption demand is equal to or greater than 50 m3/hour, and the percentage of PREP's capacity represented by these customers.

(b) Please indicate the capacity already contracted via the 2021 EOI and in the normal course of business since the close of that process by customers whose forecast hourly gas consumption demand is equal to or greater than 50 m3/hour, the number of such customers and the percentage of PREP's capacity represented by these customers.

(c) Please indicate additional capacity demand not included in parts (a) and (b) of this interrogatory forecasted for the 10 year period commencing with the proposed PREP in service date for customers whose forecast hourly gas consumption demand is equal to or greater than 50 m3/hour, the number of such forecast customers and the percentage of PREP's capacity represented by those forecast customers.

(d) Please provide the percentage of forecast peak hourly demand represented by the customers included in the responses to each of parts (a), (b) and (c) of this interrogatory.

(e) Based on the information provided in response to earlier parts of this interrogatory, please calculate the HAF that would be applicable to PREP were the HAF framework to be applied to PREP, and show the calculations.

(f) Based on the calculations provided in response to part (e) of this interrogatory, please indicate the total CIACs that would be applicable to PREP.

Response:

a) All 39 entities that provided EOI bids require greater than 50 m^3/hr.

   Enbridge Gas is in the process of executing contracts with the entities that require incremental capacity starting in 2024 and 2025 (please see the response at Exhibit I.STAFF.24, part a) for details regarding contract status including the percentage of the total incremental capacity created by the Project). Going forward, Enbridge Gas will continue to engage and negotiate with EOI bidders as well as new requests from entities that were not EOI bidders, which could result in customers attaching to the Panhandle System due to the incremental capacity provided by the Project that are less than 50 m^3/hr.

b) There is one customer who participated in the 2021 EOI with a firm distribution contract related to the Project's incremental capacity with a forecast hourly consumption demand equal to or greater than 50 m3/hour. This contract represents 34% of the total incremental capacity created by the Project.

c) The capacity demand not included in parts a) and b) above is provided in part d) below ("remaining capacity for future customers"). Future customers may or may not have hourly demands greater than or equal to 50 m3/hour.

   The proposed Project provides 168 TJ/d and would serve 5 years of the current demand forecast. Another solution will be required to serve the remainder of the 10-year demand forecast and the remaining demand will be confirmed through another EOI closer to that time.

d) Please see the information below.

	Demand (TJ/day)	Project Capacity (TJ/day)	Percent
Contracts Under Negotiations	74	168	44%
2021 EOI customers executed	57	168	34%
Remaining capacity for future customers	37	168	22%

e) Please see the response at Exhibit I.STAFF.26, part a).

f) Please see the response at Exhibit I.ED.29, part c).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Industrial Gas Users Association (IGUA)

INTERROGATORY

Reference:

EB-2020-0094 (November 5, 2020 Decision and Order on Application by EGI for approval of a System Expansion Surcharge, and Temporary Connection Surcharge and an Hourly Allocation Factor), page 20, last paragraph.

The OEB recognizes the concern of some parties about the use of HAF in transmission projects and finds Enbridge Gas's commitment to continue to explore alternatives to be acceptable. 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.

Question(s):

(a) Please discuss alternatives for application of the HAF to transmission projects explored by EGI in accord with its commitment as acknowledged by the OEB in the EB-2020-0094 excerpt referenced.

(b) If the Commission were to direct application of the HAF to PREP, please confirm that the HAF could be applied on the basis of the information included in EGI's Application. If not confirmed please particularize any impediments to doing so.

Response:

a) For clarity, Enbridge Gas's Reply Argument within EB-2020-0094 stated the following:

"In the case of the Chatham-Kent Rural project,[1] *although it involved transmission facilities, the HAF was appropriate due to the modest cost and the fact that customers were able to mitigate their costs and avoid a CIAC through reasonable contract terms and conditions, as recognized by OGVG. Enbridge Gas is continuing*

[1] EB-2018-0188.

to explore alternatives to applying EBO 134 or EBO 188 in an exclusive manner and how to reconcile the two sets of guidelines <u>in an appropriate case</u>."

The statement was made in the context of the use of HAF for distribution projects which may have a minor transmission component, and where the use of HAF could be appropriate due to its modest cost. The proposed Project is entirely a transmission project (i.e., not a distribution project, and not a "dual-function" pipeline) and HAF is not appropriate.

Enbridge Gas will continue to evaluate opportunities where HAF may apply in an appropriate case involving "dual-function" facilities, however there are no such opportunities identified at this time.

b) Not confirmed. Please see the response at Exhibit I.STAFF.26, part a).

CLEAN ENERGY SUPPLY (CES) CONTRACT

Between

BRIGHTON BEACH POWER L.P.

– and –

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

DATED as of the 27th day of April, 2023

EXHIBIT X
GAS DELIVERY SERVICES RE PANHANDLE PROJECT

1. Purpose

The purpose of this exhibit is to address the uncertainty with respect to the ability of the Supplier to secure, and the costs associated with the Supplier securing, Gas Distribution Services incremental to those expected to be transferred to the Supplier, through the construction of new pipeline capacity created by the Panhandle Project which may be impacted by an OEB decision in the proceeding EB-2022-0157 or any successive or replacement decision by the OEB in respect of the Panhandle Project (the "**Panhandle Decision**").

2. Payment for Gas Distribution Services

The Supplier shall be entitled to compensation from the Buyer with respect to the Gas Distribution Services on the following basis. If as a result of the Panhandle Decision:

(a) no additional costs or expenses are payable by the Supplier above the posted tariff with respect to the Gas Distribution Services, no additional compensation will be required in accordance with this Exhibit;

(b) either (i) a contribution in aid of construction (the "**CIAC**") or (ii) incremental costs above the posted tariff (the "**Rate Rider**"), is payable by the Supplier in connection with the Panhandle Project, the Buyer shall reimburse the Supplier for 60% of the Supplier's costs for the CIAC or Rate Rider, as applicable, as set forth in Section 3 of this Exhibit X; or

(c) the Panhandle Project does not proceed, then effective as of the Term Commencement Date, the Net Revenue Requirement, as set forth in Exhibit B, shall be increased by an amount equal to one million, two hundred thousand dollars ($1,200,000.00) divided by twelve (12) and divided by the Annual Average Contract Capacity as of the Term Commencement Date, provided that if at any time during the Term the Annual Average Contract Capacity changes, the increase to the Net Revenue Requirement as set forth in Exhibit B shall be recalculated at such time based on the new Annual Average Contract Capacity.

3. CIAC Invoice

If the Buyer is required to reimburse the Supplier for the CIAC or a Rate Rider in accordance with Section 2(b) of this Exhibit X, the Supplier shall, by the fifth (5^{th}) Business Day of each Settlement Month, prepare and deliver a detailed monthly invoice to the Buyer setting out the total amount paid by the Supplier as a result of the CIAC or Rate Rider in the previous Settlement Month, together with any reasonable supporting documentation.

4. Dispute Resolution

(a) The Buyer shall review the invoice described in Section 3 of this Exhibit. If the Buyer, acting reasonably, disputes the amount of the Supplier's invoice, then the Buyer shall provide notice thereof to the Supplier within ten (10) Business Days of receipt of the invoice and supporting documentation, along with a brief explanation of the dispute. If it is subsequently determined or agreed that an adjustment to the invoice is appropriate, the Supplier shall promptly prepare a revised invoice.

(b) Any overpayment or underpayment of an invoice shall bear interest at the Interest Rate, calculated daily from and including the time of such overpayment or underpayment to the date of the refund or payment thereof. Payment pursuant to the revised invoice shall be due at the same time as the next Monthly Payment is due for a Settlement Month. If an invoice dispute has not been resolved between the Parties within five (5) Business Days after receipt of written notice of such dispute by the Supplier, the dispute may be submitted by either Party to a Senior Conference pursuant to the terms of Section 16.1 of the Agreement; and

(c) Subject to the Buyer’s right to dispute any monthly invoice issued pursuant to Section 3 of this Exhibit, the Buyer agrees to pay to the Supplier the amount due to the Supplier under such invoice. Such payment will be due at the same time as the Monthly Payment is due for the Settlement Month to which the monthly invoice relates, provided that if the Supplier's monthly invoice and supporting documentation is not received by the Buyer within the time set out in Section 3 of this Exhibit, then following receipt thereof such payment will be due at the same time as the next Monthly Payment is due for a Settlement Month. The Buyer shall pay interest on any late payment of amounts payable pursuant to this Section 4(c) of this Exhibit at the Interest Rate, calculated daily from and including the date such payment was due to the date of payment thereof.