ENBRIDGE

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November 4, 2024

VIA RESS AND EMAIL

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

Dear Nancy Marconi:

Re: Enbridge Gas Inc. (Enbridge Gas, or the Company)
EB-2024-0111 - 2024 Rebasing – Phase 2 ADR Information Requests

Enbridge Gas filed Phase 2 of its 2024 Rates Application on April 26, 2024. In this Application, Enbridge Gas requested approval of an incentive rate-setting mechanism (IRM) for the years from 2025 to 2028 and updated 2024 rates effective January 1, 2024. On June 12, 2024, Enbridge Gas filed further evidence regarding Enbridge Sustain.

In Procedural Order No. 2, dated May 30, 2024, the OEB ordered a Settlement Conference to be held September 10 to 12, and in Procedural Order No. 7, dated September 26, 2024, the OEB ordered an extension to that Settlement Conference from October 7 to October 11. Enclosed are responses to supplementary requests for information that were made during the settlement conference process. All parties agreed that it is appropriate for these items to be included on the public record for this proceeding.

Should you have any questions, please let us know.

Sincerely,

Joel Denomy

Joel Denomy
Technical Manager, Strategic Applications – Rate Rebasing

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference:

[1.13-SEC-8]

Question(s):

Please provide the forecast 2024:

a) Union Rate Zone Working Storage Space
b) EGD Rate Zone Working Storage Space
c) Union Rate Zone Withdrawal Capability
d) EGD Rate Zone Withdrawal Capability

Response:

Please see Table 1.

Table 1

Description	Total	Utility	Non-Utility
Union Rate Zones working storge space (PJ)	186.7	100.0	86.7
EGD Rate Zone working storage space (PJ)	127.4	99.4	28
Union Rate Zones withdrawal capability (PJ/d)	4.0	2.2	1.8
EGD Rate Zone withdrawal capability (PJ/d)	2.6	1.9	0.7

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference:

[JT3.28, Attach 1, Table 5, Ln 60]

Question(s):

Please provide the increase in storage space and/or withdrawal capability expected in 2024 as a result of the 2025-2027 Storage Enfacement Project.

Response:

No increase in storage space and/or withdrawal capability is expected in 2024 as a result of the 2025 to 2027 Storage Enhancement Project.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

With respect to the attached document from the IRP TWG:

a) Does the document show the most up to date forecasts? If not, please provide the most up to date information.

b) Please confirm that the fall 2023 AMP. Addendum (filed in EB-2022-0091) is based on a previous customer addition forecast.

c) Please confirm that the AMP expected to be completed this fall, is based on the customer attachment numbers included in the attached document.

d) Please confirm that a new customer addition forecast is expected to be completed by Q1, 2025.

Response:

a) Yes, this is the most current information available.

b) Yes, the fall 2023 AMP Addendum was based on the customer addition forecast from Q1, 2023.

c) Yes, the AMP to be completed fall 2024 is based on the numbers in the attached, as those numbers represent the most current information available.

d) Yes, the update to the new customer addition forecast is expected to be completed in Q1, 2025.

IRP TWG Information Request from June 19, 2024 - Meeting 39

1. Enbridge to provide a table that shows housing starts, # of gas connections in the base forecast, and the # of gas connections in the adjusted forecast broken down between Ontario and Toronto forecasting out to 2034.
2. Enbridge to provide a table that shows its actual forecast of customers that will switch off gas each year until 2034.

Tables 1 and 2 provide the requested data for Request No. 1. Table 3 provides the requested data for Request No. 2.

For your reference, Enbridge Gas's (EGI's) forecasting process for Customer Additions and Existing Customers is provided in EB-2022-0200 Exhibit 3, Tab 2, Schedule 6.

As noted in EB-2022-0200 Exhibit 1, Tab 10, Schedule 4, EGI included energy transition adjustments into its forecasting and planning processes based on best available information at the time. As noted in the Reply Argument for EB-2022-0200, on an annual basis, EGI will review these adjustments and determine if any changes are warranted. The following information for Customer Additions for Ontario (Table 1) and Toronto (Table 2), and Existing Customers (Table 3) include the 2024 energy transition adjustment factors.

Table 1: Ontario Non-Apartment Housing Starts & EGI Customer Additions Forecasts - Base and Adjusted - Ontario (includes Toronto) 2025 to 2034

Year	2024 Ontario Housing Non-Apartment Starts [1,2]	Base Economic Forecast for Customer Additions [3]	Adjusted Customer Additions Forecast [3]
2025	39,132	42,711	40,533
2026	38,850	42,072	38,879
2027	38,153	41,100	37,000
2028	37,467	40,161	35,200
2029	36,823	39,304	33,382
2030	35,408	37,788	31,190
2031	34,020	36,367	29,209
2032	32,556	34,915	27,234
2033	31,113	33,502	25,330
2034	29,763	32,213	23,590
Total	353,285	380,134	321,547

Notes:

1. Non-Apartment Ontario Housing Starts are based on the Consensus Forecast. Additional details on the Consensus Forecast are provided in EB-2022-0200 Exhibit 3, Tab 2, Schedule 4.
2. Ontario Non-Apartment Housing Starts are based on the 2024 and 2025 Consensus Forecast with the Conference Board of Canada growth rate applied to the end of the forecast period.
3. Includes New Construction and Conversion Customers, and excludes community expansion.

Table 2: EGI Customer Additions Forecasts - Base and Adjusted – Toronto 2025 to 2034

Year	Base Economic Forecast for Customer Additions[1, 2]	Adjusted Customer Additions Forecast [2]
2025	1,803	1,752
2026	1,742	1,601
2027	1,676	1,456
2028	1,616	1,286
2029	1,559	968
2030	1,480	713
2031	1,411	539
2032	1,340	376
2033	1,274	231
2034	1,213	98
Total	15,114	9,020

Notes:

1. There is no Toronto specific Housing Starts. EGI relies upon the Ontario Non-Apartment Housing Starts and historical regional data to allocate a base forecast to Toronto.
2. Includes New Construction and Conversion Customers, and excludes community expansion.

Table 3: Customer Egress Forecast (Annual Rate)– Ontario (includes Toronto) & Toronto - 2025 to 2034

Year	Ontario (includes Toronto)	Toronto
2025	3,146	444
2026	3,172	448
2027	6,656	1504
2028	10,179	2573
2029	13,727	3646
2030	16,433	3865
2031	19,138	4079
2032	21,832	4288
2033	24,505	4496
2034	27,159	4696
Total	145,947	30,039

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

Enbridge's GDS scorecard includes: "Quantity of growth capital commercially secured (Million): Capital committed to organic growth projects or acquisitions."

a) How is growth capital defined?

b) Please provide a table showing the growth capital according to this definition in 2023 and for each year until 2028, the total capital for each year, and growth capital as a percent of total?

Response:

a) The GDS scorecard is used to measure performance of a number of entities that are managed within the Gas Distribution segment at Enbridge, Enbridge Gas being one of them. Growth Capital refers to not only regulated business growth but also unregulated business growth, including mergers, acquisitions, and growth within Affiliate companies. Within the regulated segment of Enbridge Gas, growth capital refers to assets within the AMP, primarily customer connections and reinforcement expenditures

b) Please see response at Exhibit I.ADR-5.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

EB-2022-0200, Exhibit 2, Tab 5, Schedule 1, Page 8 states as follows: "Figure 2 provides a different view of Enbridge Gas's capital expenditures from 2023 to 2032, with expenditures re-classified into three main categories: Sustainment, Replacement and Growth."

a) Please provide a table with a breakdown of actual 2023 spending and forecast 2024-2028 spending in those categories, the annual capital spending totals, and the growth spending as a percent of the annual totals.

b) Please provide a side-by-side showing Table 2 on page 13 of the above evidence reference and an updated version of that table.

Response:

a-b) Table 1 shows the updated actuals and forecast including overheads for 2023 and 2024 as compared to the Capital Update:

Table 1

Investment Sub-Category ($ Millions)	Capital Update 2023	2023 YE Actuals	Capital Update 2024	2024 Estimate
Gas Infrastructure - Replacement - Reactive	51.2	71.3	60.7	55.2
Gas Infrastructure - Replacement - Proactive - Short Term (1y +)	353.9	360.4	147.5	56.3
Gas Infrastructure - Replacement - Proactive - Long Term (20y +)	1.9	1.4	1.4	0.4
Gas Infrastructure - Replacement - Proactive - Long Term Cost Effectiveness	34.0	22.2	39.7	17.3
Gas Infrastructure - Sustainment	391.8	372.0	472.7	402.9
Gas Infrastructure - Growth - Customer Connections	325.0	375.8	333.6	329.7
Gas Infrastructure - Growth - System Reinforcement[1]	112.8	94.7	277.4	225.5
Business Sustainment	119.9	140.1	195.8	134.6

[1] Includes PREP Project

Emission Reductions	0.8	0.8	1.8	0.5
Energy Transition	38.4	4.2	134.1	51.9
Grand Total	**1429.9**	**1442.8**	**1665.2**	**1274.4**
Growth Category as % of total spend	30.6%	32.6%	36.7%	43.6%

The assignment of the investment sub-categories in Table 1 was a one-time exercise to further breakdown the total forecasted capital allocations, and as such, these categories are no longer used in the development of future forecasts.

The updated forecasts within the 2025 to 2034 Asset Management Plan (AMP) to be filed later this year will reflect newly developed capital definitions. Given that the AMP is still in the stages of finalization, the forecasts at Table 2 are approximate and may be subject to change up until the filing date.

Table 2

Investment Category ($ Millions)	**2024 Estimate**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**
Customer Growth	408.0	418.2	459.5	311.0	276.5
Discrete	233.8	148.4	193.9	221.4	292.8
Programmatic - Component Replace	23.0	53.5	54.7	64.0	61.4
Programmatic - EA Fixed Overheads	39.3	40.0	41.0	42.1	43.2
Programmatic - Full Replace	205.6	264.7	265.2	262.1	234.1
Programmatic - Maintain	364.8	400.2	388.2	383.8	360.7
Grand Total	**1274.4**	**1324.9**	**1402.6**	**1284.4**	**1268.6**
Growth Category as % of total spend[2]	48.1%[3]	36.4%	38.3%	36.8%	37.9%

[2] Includes the growth within the Discrete category.
[3] The 2024 growth percentage in the new capital definitions (48.1%) include CNG, RNG and Community Expansion spend in Customer Growth whereas in the old categorizations, CNG, RNG, and Community Expansion were reflected in Energy Transition and do not contribute to the overall growth percentage (43.6%).

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

If the OEB were to direct that Enbridge's revenue be decoupled from the customer count (such that increases in customer numbers would not impact revenue), please describe a number of options to achieve that from a regulatory perspective and indicate which option would be preferred by Enbridge from among those options.

Response:

Enbridge Gas is unable to comment on ED's proposed approach on revenue decoupling as it has not developed or assessed such an option, and how this mechanism would work under a price cap setting methodology.

Conceptually, revenues could be decoupled from customer count during the IRM term if a revenue cap mechanism is adopted potentially with fully fixed distribution charges or a constant volumetric forecast, but that is not Enbridge Gas's proposal, nor does it fit with what Enbridge Gas understands to be the OEB's current ratemaking policies. In any event, substantial work and analysis would be required to develop any alternative proposal.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Please advise where the Dawn H Project and the Meter Area Upgrade Project discussed in JT3.32 are shown in the detailed project-specific tables at JT3.28/Attachment 1.

b) Please explain the difference between the additions shown at I.1.13-FRPO-10 and those provided in JT3.28. In some years, there appear to be material differences in the additions shown in each of the above noted schedules.

As an example, for the EGD Rate Zone in 2021, the additions to utility plant shown in FRPO-10 are much larger than the additions provided at JT3.28.

FRPO-10/Attachment 2 – 2021

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2021 ACTUAL

Line No.	Particulars ($ Millions)	Opening Balance Dec.2020	Additions	Retirements	Closing Balance Dec.2021	Regulatory Adjustment	Utility Balance Dec.2021	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	EGD Rate Zone Underground Storage Plant							
1.	Land and gas storage rights (450/451)	47.6	1.3	-	48.9	(1.0)	47.9	46.6
2.	Structures and improvements (452)	31.5	0.6	-	32.1	(0.1)	32.0	31.5
3.	Wells (453)	70.0	22.4	-	92.4	-	92.4	71.0
4.	Well equipment (454)	12.6	0.7	-	13.4	-	13.4	12.7
5.	Field Lines (455)	115.4	12.3	-	127.7	-	127.7	115.9
6.	Compressor equipment (456)	159.7	36.4	-	196.2	(0.5)	195.7	164.3
7.	Measuring and regulating equipment (457)	11.2	-	-	11.2	-	11.2	11.2
8.	Base pressure gas (458)	32.4	-	-	32.4	-	32.4	32.4
9.	Sub-Total	480.5	73.8	-	554.3	(1.5)	552.7	485.6

JT3.28/Attachment 1/Table 2 (EGD)

Table 2 - EGD Storage In-Service Additions Over $0.5 million

Category ($ millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
a) new storage assets resulting in additional capacity and deliverability												
i) total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.3	$ 2.5	$ 10.2	$ 2.3	$ 22.4
ii) allocated to regulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.3	$ 2.5	$ 10.2	$ 2.3	$ 22.4
b) new storage assets to maintain existing assets or replace end-of-life assets												
i) total	$ 6.4	$ 8.1	$ 8.4	$14.1	$17.9	$13.0	$11.1	$52.2	$53.9	$ 360.4	$ 39.7	$ 585.2
ii) allocated to regulated business	$ 6.4	$ 8.1	$ 8.4	$14.1	$15.8	$13.0	$11.1	$48.4	$51.5	$ 360.4	$ 33.7	$ 570.9
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ 2.1	$ -	$ -	$ 3.7	$ 2.4	$ -	$ 6.1	$ 14.3
c) new assets for replacing and enhancing an existing asset that is at the end of its useful life												
i) total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ii) allocated to regulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
d) new assets for replacing and enhancing an existing asset that is not at the end of its useful life												
i) total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ii) allocated to regulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 6.4	$ 8.1	$ 8.4	$14.1	$17.9	$13.0	$11.1	$59.5	$56.5	$ 370.6	$ 42.0	$ 607.6

As another example, for the Union Rate Zone in 2023, the additions to utility plant shown in FRPO-10 are much larger than the additions provided at JT3.28.

FRPO 10/Attachment 2 – 2023

EGI UTILITY GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2023 ACTUAL

Line No.	Particulars ($ Millions)	Opening Balance Dec.2022	Additions	Retirements	Closing Balance Dec.2023	Regulatory Adjustment	Utility Balance Dec.2023	Average of Monthly Averages
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Union Rate Zones Underground Storage Plant							
1.	Land (450)	11.0	0.0	-	11.0	-	11.0	11.0
2.	Land rights (451)	32.0	0.0	-	32.0	-	32.0	32.0
3.	Structures and improvements (452)	70.7	1.2	(0.2)	71.8	-	71.8	70.9
4.	Wells (453)	49.2	0.5	-	49.8	-	49.8	49.3
5.	Field Lines (455)	54.3	5.2	(0.0)	59.5	-	59.5	55.7
6.	Compressor equipment (456)	479.1	2.6	-	481.7	-	481.7	480.1
7.	Measuring and regulating equipment (457)	63.1	95.1	-	158.2	-	158.2	74.0
8.	Base pressure gas (458)	36.2	-	-	36.2	-	36.2	36.2
9.	Regulatory Overheads	27.7	23.2	-	50.9	-	50.9	35.0
10.	Sub-Total	823.4	127.9	(0.2)	951.1	-	951.1	844.2

JT3.28/Attachment 1/Table 3 (Union)

Table 3 - UG Storage In-Service Additions Over $0.5 million

Category ($ millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
a) new storage assets resulting in additional capacity and deliverability												
i) total	$ -	$13.3	$ -	$ -	$30.6	$ -	$ -	$ -	$31.7	$ -	$ -	$ 75.6
ii) allocated to regulated business (1)	$ -	$ -	$ -	$ -	$ 1.1	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.1
iii) allocated to unregulated business	$ -	$13.3	$ -	$ -	$29.5	$ -	$ -	$ -	$31.7	$ -	$ -	$ 74.5
b) new storage assets to maintain existing assets or replace end-of-life assets												
i) total	$ 2.6	$ 6.9	$ 1.9	$11.7	$ 3.4	$ 4.2	$10.8	$ 9.3	$ 7.6	$ 13.7	$ 9.4	$ 81.7
ii) allocated to regulated business	$ 2.0	$ 5.8	$ 1.6	$ 6.5	$ 2.3	$ 2.6	$ 6.6	$ 3.8	$ 5.2	$ 6.0	$ 6.0	$ 48.5
iii) allocated to unregulated business	$ 0.5	$ 1.1	$ 0.3	$ 5.2	$ 1.1	$ 1.6	$ 4.2	$ 5.6	$ 2.5	$ 7.7	$ 3.5	$ 33.2
c) new assets for replacing and enhancing an existing asset that is at the end of its useful life												
i) total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ii) allocated to regulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
d) new assets for replacing and enhancing an existing asset that is not at the end of its useful life												
i) total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ 0.5
ii) allocated to regulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
iii) allocated to unregulated business	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.5	$ 0.5
Total	$ 2.6	$20.2	$ 1.9	$11.7	$34.0	$ 4.2	$10.8	$ 9.3	$39.4	$ 13.7	$ 9.9	$ 157.8

Response:

a) Dawn H was removed from Exhibit JT3.28 Attachment 1. It was part of 2017 Storage additions shown in Exhibit JT3.32, however, it serves a purely transmission function for Dawn-Parkway and is not subject to allocation between regulated and unregulated storage and was therefore, removed from Exhibit JT3.28 Attachment 1. The Meter Area projects are included on lines 20 & 21 of Exhibit JT3.28 Attachment 1, Table 4.

b) For 2023 the continuity provided in Exhibit I.1.13-FRPO-10 contained a presentation difference that did not reflect the final unitization of 2023 additions that were reflected appropriately in the 2023 ESM and Deferrals Disposition (EB-2023-0092, Exhibit B, Tab 1, Schedule 4), please see below:

EGI Utility Gross Plant
Year End Balances and Average of Monthly Averages
2023 Actual

Line No.		Col. 1 Opening Balance Dec.2022 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Closing Balance Dec.2023 ($Millions)	Col. 5 Regulatory Adjustment ($Millions)	Col. 6 Utility Balance Dec.2023 ($Millions)	Col. 7 Average of Monthly Averages ($Millions)
	EGD Rate Zone Underground Storage Plant							
1	Land and gas storage rights (450/451)	48.9	0.0	(0.0)	48.9	(1.0)	47.9	47.9
2	Structures and improvements (452)	35.3	0.9	(0.1)	36.2	(0.1)	36.1	35.3
3	Wells (453)	95.8	(0.5)	(0.4)	94.9	-	94.9	94.3
4	Well equipment (454)	14.1	2.6	(0.1)	16.6	-	16.6	16.2
5	Field Lines (455)	134.7	136.2	-	270.9	-	270.9	137.4
6	Compressor equipment (456)	231.5	41.4	-	272.9	(0.5)	272.4	256.3
7	Measuring and regulating equipment (457)	11.2	175.5	-	186.7	-	186.7	37.3
8	Base pressure gas (458)	32.4	-	-	32.4	-	32.4	32.4
9	Sub-Total	603.9	356.1	(0.5)	959.5	(1.5)	958.0	657.0

As shown above, the actual 2023 in-service additions in the EGD Rate Zone were $356.1M inclusive of Dawn to Corunna which is in line with the response provided in Exhibit JT3.28 for the EGD Rate Zone in 2023. The Union Rate Zones continuity from that same exhibit is provided below:

	Union Rate Zones Underground Storage Plant							
48	Land (450)	11.0	0.0	-	11.0	-	11.0	11.0
49	Land rights (451)	32.0	0.0	-	32.0	-	32.0	32.0
50	Structures and improvements (452)	70.7	0.5	(0.2)	71.0	-	71.0	70.8
51	Wells (453)	49.2	0.5	-	49.8	-	49.8	49.3
52	Field Lines (455)	54.3	5.2	(0.0)	59.5	-	59.5	55.7
53	Compressor equipment (456)	479.1	2.6	-	481.7	-	481.7	480.1
54	Measuring and regulating equipment (457)	63.1	0.3	-	63.5	-	63.5	63.2
55	Base pressure gas (458)	36.2	-	-	36.2	-	36.2	36.2
56	Regulatory Overheads	27.7	2.0	-	29.7	-	29.7	28.4
57	Sub-Total	823.4	11.2	(0.2)	834.4	-	834.4	826.8

In addition to the variance related to Dawn to Corunna, there are variances in all years between Exhibit JT3.28 Attachment 1 and Exhibit JT3.32, as JT3.28 Attachment 1 is based on projects that serve a storage function and with a total project cost greater than $0.5 million. Exhibit JT3.28 is intended to capture the majority of storage projects but is not intended to tie to the plant addition schedules included in Exhibit JT3.32.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

At Exhibit 4/Tab 2/Schedule 5/p. 7, Enbridge Gas noted that the forecast 2024 storage withdrawal requirement to serve in-franchise customers is 2.2 PJ/d, which exceeds the reserved cost-based maximum firm withdrawal of 1.9 PJ/d as provided in Table 2.

Table 2
Total Maximum Firm Withdrawal and Injection Capability – to Serve Union Rate Zone Customers

Line No.	Particulars (PJ/d)	Total	Utility	Non-Utility
		(a)	(b)	(c)
	One-Time Separation of Plant			
1	Storage Allocation Factor (1)		62.3%	37.7%
	Withdrawal/Dehydration Capability			
2	Total Shared Capability (2)	3.0	1.9	1.1
3	Direct Investment	1.0	-	1.0
4	Total Maximum Withdrawal Capability (3)	4.0	1.9	2.1
	Injection Capability			
5	Total Shared Capability (2)	1.4	0.9	0.5
6	Direct Investment	0.6	-	0.6
7	Total Maximum Injection Capability	2.0	0.9	1.1

Notes:
(1) Approved storage allocation per EB-2011-0038.
(2) Allocated in proportion to line 1.
(3) Based on design day capacity for February 29, 2024.

At Technical Conference Transcript Vol. 3/pp. 104-105, Enbridge Gas stated:

MR. GILLETT: Absolutely. Yeah, absolutely. So I will turn it over to my colleagues here in a moment to maybe fill in some gaps.

But what our evidence tried to outline is that over the years, as the demands of the Union rate zone have increased, storage almost acted like a plug. Like, they got what they wanted in terms of deliverability. So as the gas supply plans needs for deliverability crept up over the years, they got that deliverability.

And our proposal, as you are aware, is to place a cap of 1.9 PJs on that. But what you are seeing here is that deliverability requirement of the plan has just crept up over the years due to the requirements of the plan. They essentially got what they wanted, despite the fact that the unregulated side of the business was making the investment in the increased deliverability. The utility side essentially got whatever deliverability they requested from the gas supply plan. And that is driving those numbers creeping up.

a) In the circumstance that utility customers require deliverability in excess of the proposed 1.9 PJ/d cap:

   i. How has that demand been met historically?
   ii. How will that demand be met going forward and how will the related costs be recovered?

b) Please explain how the 3.0 PJ/d of total shared capability (line 2 / column a) in Table 2 was derived and please provide the evidentiary reference where it was originally presented.

Response:

a)

   i. As detailed in the Company's pre-filed evidence at Phase 2 Exhibit 4, Tab 2, Schedule 5, Table 1, p. 5, utility customer demand for withdrawal capability (deliverability) exceeding the proposed 1.9 PJ/d cap by 0.3 PJ/d has been met by commensurately reducing the amount of deliverability available to serve non-utility storage customers.

   ii. Upon implementation, utility customer demand formerly served via deliverability exceeding the 1.9 PJ/d cap will instead be served via incremental supply purchases at Dawn (as required) as reflected in the Company's Gas Supply Plan as described at Exhibit 4, Tab 2, Schedule 1, p. 14. The cost of incremental supply purchases will be recovered through the reference price and the Purchased Gas Variance Account (PGVA).

b) The Total Shared Capability of Withdrawal/Dehydration Capability of 3.0 PJ/d for the Union rate zones (line 2 of Table 2)[1] was derived by calculating the difference between the Company's current total capability of 4.0 PJ/d (line 4 of Table 2),[2] and

[1] The total capability existing at the time of NGEIR (utility and non-utility)
[2] As of the date of this response, the Company's total Withdrawal/Dehydration capability for the Union Rate Zones remains 4 PJ/d.

the total non-utility capability developed by the non-utility storage business since NGEIR in 2007 through direct investment into storage facilities (line 3 of Table 2).[3] Please see Table 1 below for a simplified calculation with references to the Line No. set out in Table 2.

Table 1
Calculation of Total Shared Capability of Withdrawal/Dehydration Capability – Union Rate Zones

Line No.	Particulars	Withdrawal/Dehydration Capability (PJ/d)
4	Total Maximum Withdrawal Capability	4.0
3	Direct Unregulated Storage Investment	1.0
2	Total Shared Capability (line 4 – line 3)	3.0

The calculation of total shared withdrawal/dehydration capability for the Union rate zones has not previously been presented to the OEB.

[3] Exhibit 4, Tab 2, Schedule 5, Table 2, p. 7.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

On day 3 of the technical conference, we were trying to understand the load balancing implications of the proposed gas supply plan found Ex4 T2 Sch1, Attach1 pg.5. The undertaking, JT3.6, had asked to explain the difference in the load balancing need but the answer provided only numerical calculation of summer and winter purchases between the two.

We were seeking a better understanding of why the utility reduced deliveries in January and increased deliveries in the summer. We have attached an update spreadsheet only adding a few formulae to the base data. Our specific questions are:

a) Please explain what drove a reduction in January deliveries and an increase in summer deliveries

b) Please confirm that 110 TJ/day added to Dec.-Feb. would, in effect, reduce deliverability required from storage by 0.11 PJ/day

c) Please confirm the difference in cost of adding 110 TJ/day during those winter months while reducing 10PJ in the summer is forecasted, by the company's forecasted prices as costing $5.5M

Response:

a) The GSP utilizes storage such that supply purchases are increased in lower priced, summer months and injected into storage which is offset by a decrease in supply purchases in higher priced, winter months. This utilization of storage is reflected in the Phase 2 evidence when 10 PJ of storage capacity is added. July and August purchases increase by a total of 10 PJ and January purchases are reduced by 10 PJ.

b) Confirmed. Winter supply purchases can be an alternative to the required deliverability from storage to meet a peak day demand.

Enbridge Gas engaged ICF to assist with assessing the cost and risk of its total storage portfolio against purchasing winter supplies to ensure an appropriate balance of cost and risk. ICF's recommendation, found at Phase 2 Exhibit 4, Tab 2, Schedule 1, Attachments 2 and 3, serves to partially offset the overall risk to Enbridge Gas's storage portfolio, resulting in an increase in market-based storage of 2 PJ over the current amount held by Enbridge Gas, which has remained consistent since 2018.

Enbridge Gas notes that the impact of adding 10 PJ of storage to Enbridge Gas's portfolio is an incremental deliverability from storage of 120 TJ/d. Therefore, reducing the portfolio by 10 PJ would reduce design day deliverability, accordingly.

c) Enbridge Gas notes the scenario as put forward by FRPO adds 110 TJ/d of Dawn supply purchases each day during the months December to February and offsets those purchases by reducing June supply purchases by an equal amount. This scenario increases forecasted costs by $5.5 million.

	PHASE 1 & 2 EGI - 10 PJ
Load Balancing/Space (TJ)	10,010
Days in winter (Dec.-Feb)	91
Additional Dawn Daily Purchase Equivalent (TJ)	110.0

P1,EX.4,T2,SCH 1, ATT, 1, PG.5

												DAILY DELIVERIES	345			EXCESS
MONTH	January	February	March	April	May	June	July	August	Septembe	October	November	December	Annual	WINTER	SUMMER	WINTER
Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365	SUPPLY	SUPPLY	SUPPLY
Supplies (TJ)	20,379	23,600	0	2,012	4,000	13,200	7,686	0	10,823	10,440	10,024	24,150	126,314	78,153	48,161	29,992
Average Day Demand Per Month (TJ)	10,699	10,008	10,354	10,699	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314			
Average Purchases Variance (TJ)	9,680	13,592	(10,354)	(8,687)	(6,699)	2,846	(3,013)	(10,699)	469	(259)	(330)	13,451				
Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551				
Price Variance - Load Balancing ($000s) (1)	55,584	76,955	54,191	45,266	34,405	14,511	15,320	54,467	2,369	1,307	1,745	74,668	17,387			
Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201			
Total Load Balancing Costs ($000s) (2)	56,108	77,479	53,667	44,753	33,892	15,024	14,807	53,954	2,882	794	1,232	75,192	23,587			

P1 - SPREAD JUNE PURCHASES OVER DEC-FEB 91 DAYS 10010

													DAILY DELIVERIES	345			EXCESS
1	MONTH	January	February	March	April	May	June	July	August	Septemb	October	Novemb	Decemb		WINTER	SUMMER	WINTER
2	Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365	SUPPLY	SUPPLY	SUPPLY
3	Supplies (TJ)	23,789	26,790	0	2,012	4,000	3,190	7,686	0	10,823	10,440	10,024	27,560	126,314	88,163	38,151	50,012
4	Average Day Demand Per Month (TJ)	10,699	10,008	10,354	10,699	10,699	10,354	10,699	10,699	10,354	10,699	10,354	10,699	126,314			
5	Average Purchases Variance (TJ)	13,090	16,782	(10,354)	(8,687)	(6,699)	(7,164)	(3,013)	(10,699)	469	(259)	(330)	16,861				
6	Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551				
7	Price Variance - Load Balancing ($000s) (1)	75,164	95,017	(54,191)	(45,266)	(34,405)	(36,520)	(15,320)	(54,467)	2,369	(1,307)	(1,745)	93,597	22,927			
8	Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201			
	Total Load Balancing Costs ($000s) (2)	75,688	95,541	(53,667)	(44,753)	(33,892)	(36,007)	(14,807)	(53,954)	2,882	(794)	(1,232)	94,121	29,127			

ADDITIONAL COST OF 10TJ 5,540
CREATED BY DELIVERING GAS DEC TO FEB INSTEAD OF JUNE

P2, EX.4,T2,SCH 1, ATT, 1, PG.5

											DAILY DELIVERIES		342			EXCESS
1	MONTH	January	February	March	April	May	June	July	August	Septembe	October	November	December	Annual	WINTER	SUMME	WINTER
2	Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365	SUPPLY	SUPPLY	SUPPLY
3	Supplies (TJ)	10,439	23,600	0	2,012	4,000	13,200	13,640	2863	10,923	10,440	10,024	24,150	125,291	68,213	57,078	11,135
4	Average Day Demand Per Month (TJ)	10,612	9,927	10,270	10,612	10,612	10,270	10,612	10,612	10,270	10,612	10,270	10,612	125,291			
5	Average Purchases Variance (TJ)	(173)	13,673	(10,270)	(8,600)	(6,612)	2,930	3,028	(7,749)	653	(172)	(246)	13,538				
6	Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551				
7	Price Variance - Load Balancing ($000s) (1)	(994)	77,414	(53,752)	(44,815)	(33,960)	14,938	15,397	(39,451)	3,297	(869)	(1,301)	75,149	11,054			
8	Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201			
	Total Load Balancing Costs ($000s) (2)	(470)	77,938	(53,228)	(44,302)	(33,447)	15,451	15,910	(38,938)	3,810	(356)	(788)	75,673	17,254			
	DIFFERENCE BETWEEN PURCHASE PLAN: BETWEEN PHASE 1 EVID, & PHASE 2 EVID.	-9,940						5,954	2,863	100							

SPREAD JUNE PURCHASES OVER DEC-FEB 91 DAYS 10010

												DAILY DELIVERIES	342			EXCESS
MONTH	January	February	March	April	May	June	July	August	September	October	November	December		WINTER	SUMME	WINTER
Days in Month	31	29	30	31	31	30	31	31	30	31	30	31	365	SUPPLY	SUPPLY	SUPPLY
Supplies (TJ)	13,849	26,790	0	2,012	4,000	3,190	13,640	2863	10,923	10,440	10,024	27,560	125,291	78,223	47,068	31,155
Average Day Demand Per Month (TJ)	10,612	9,927	10,270	10,612	10,612	10,270	10,612	10,612	10,270	10,612	10,270	10,612	125,291			
Average Purchases Variance (TJ)	3,237	16,863	(10,270)	(8,600)	(6,612)	(7,080)	3,028	(7,749)	653	(172)	(246)	16,948				
Dawn Forecasted Price ($/GJ)	5.742	5.662	5.234	5.211	5.136	5.098	5.085	5.091	5.047	5.050	5.294	5.551				
Price Variance - Load Balancing ($000s) (1)	18,586	95,476	(53,752)	(44,815)	(33,960)	(36,093)	15,397	(39,451)	3,297	(869)	(1,301)	94,078	16,594			
Demand Cost - Load Balancing ($000s)	524	524	524	513	513	513	513	513	513	513	513	524	6,201			
Total Load Balancing Costs ($000s) (2)	19,110	96,000	(53,228)	(44,302)	(33,447)	(35,580)	15,910	(38,938)	3,810	(356)	(788)	94,602	22,794			
												ADDITIONAL COST OF 10TJ	5,540			

CREATED BY DELIVERING GAS DEC TO FEB INSTEAD OF JUNE

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

In attempting to understand deliveries and limitations of the integrated Dawn-Corunna storage network, we asked questions in Ex.I.1.13-FRPO-25. We would like to clarify a few matters.

a) The data in Table 1 shows unit operation. Our more specific question is: Was gas channeled through the dehydration system during every day in those periods?
   i. If not, please provide the dates that gas was sent through the dehydration system.

b) The schematic provided in Figure 1 and 2 show design day flows. Please add:
   i. The design day flow from the 6160 kPa outlet to the Dawn-Parkway system
   ii. Any storage pools that flow directly into the Dawn-Parkway system and their design day capability of flow
   iii. The Panhandle system outlet from Dawn
   iv. Any storage pools that flow directly into the Panhandle system and their design day capability of flow

Response:

a) Yes.

b) Please see Attachment 1 for the updated schematics. All storage pools connected to the Dawn-Parkway system are empty on design day and therefore are not flowing. Additionally, one storage pool flows into the Panhandle system on design day however, the flow is insignificant (0.006 PJ) and is rounded to 0.0 to align with the significant digits provided on the schematic.

Figure 1

System Schematic

W23/24 Design Day

Base Case

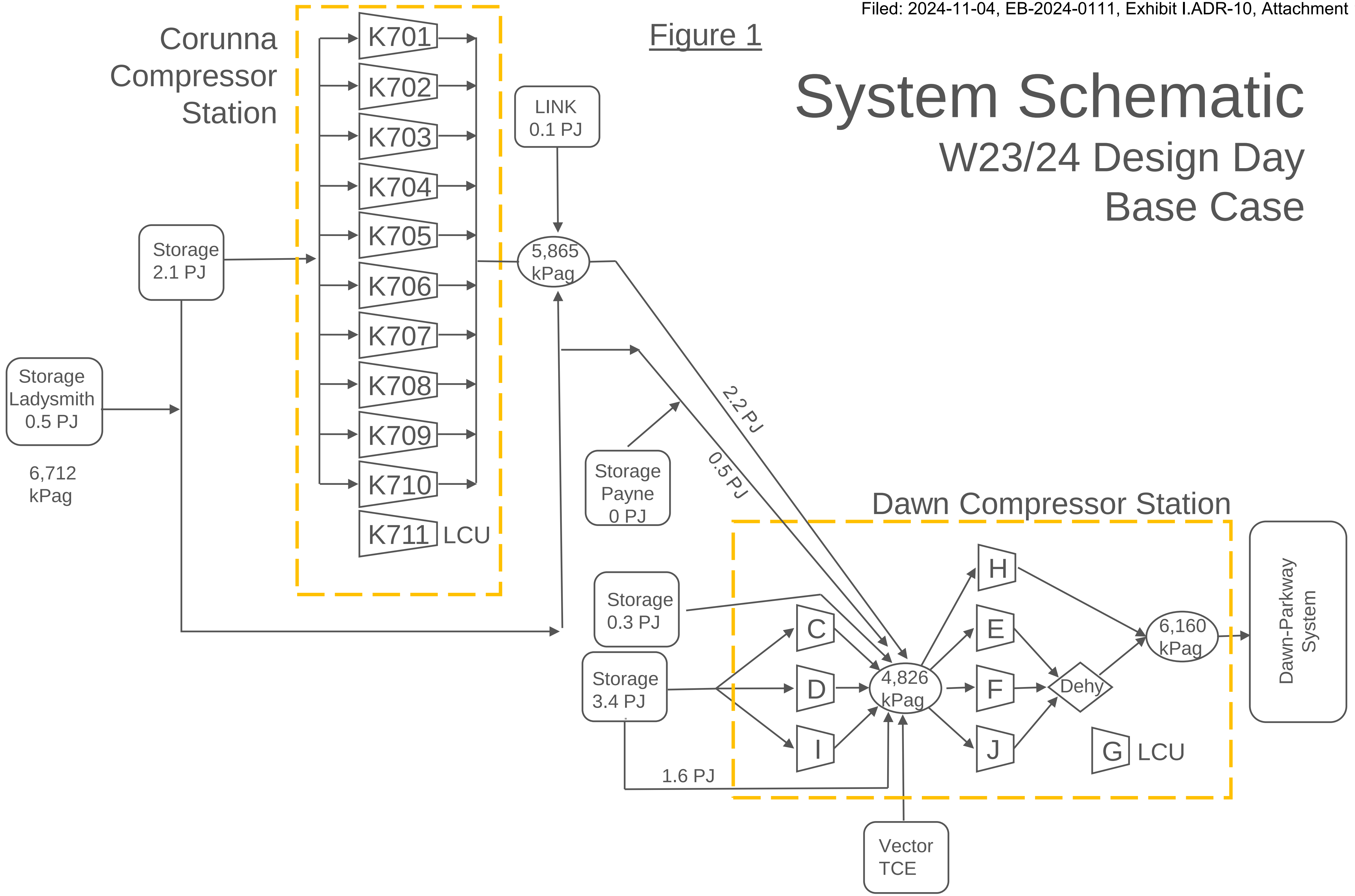


Figure 2

System Schematic

W23/24 Design Day With TR7

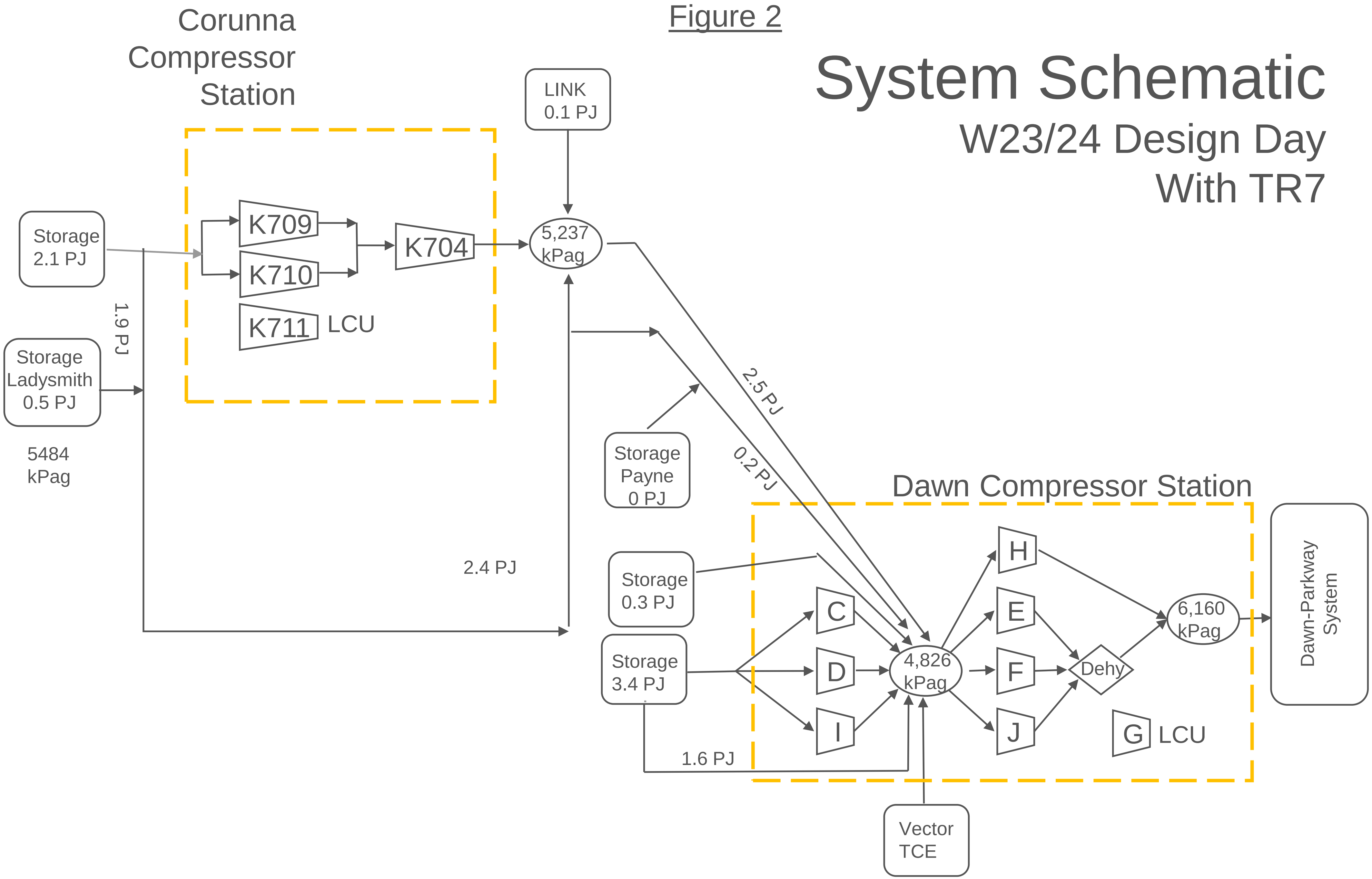


Figure 1

System Schematic

W23/24 Design Day
Base Case
Pre-settlement FRPO

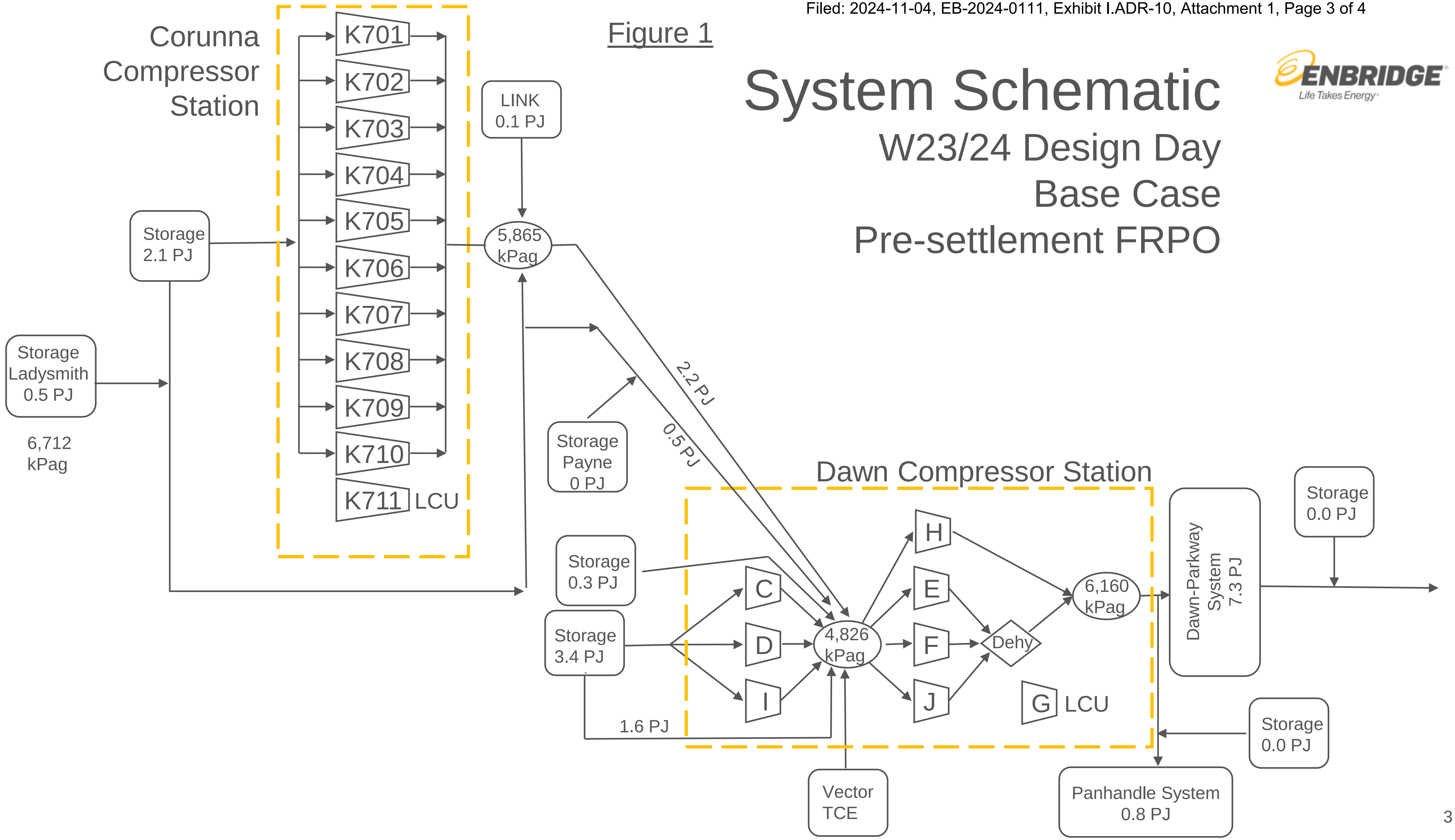
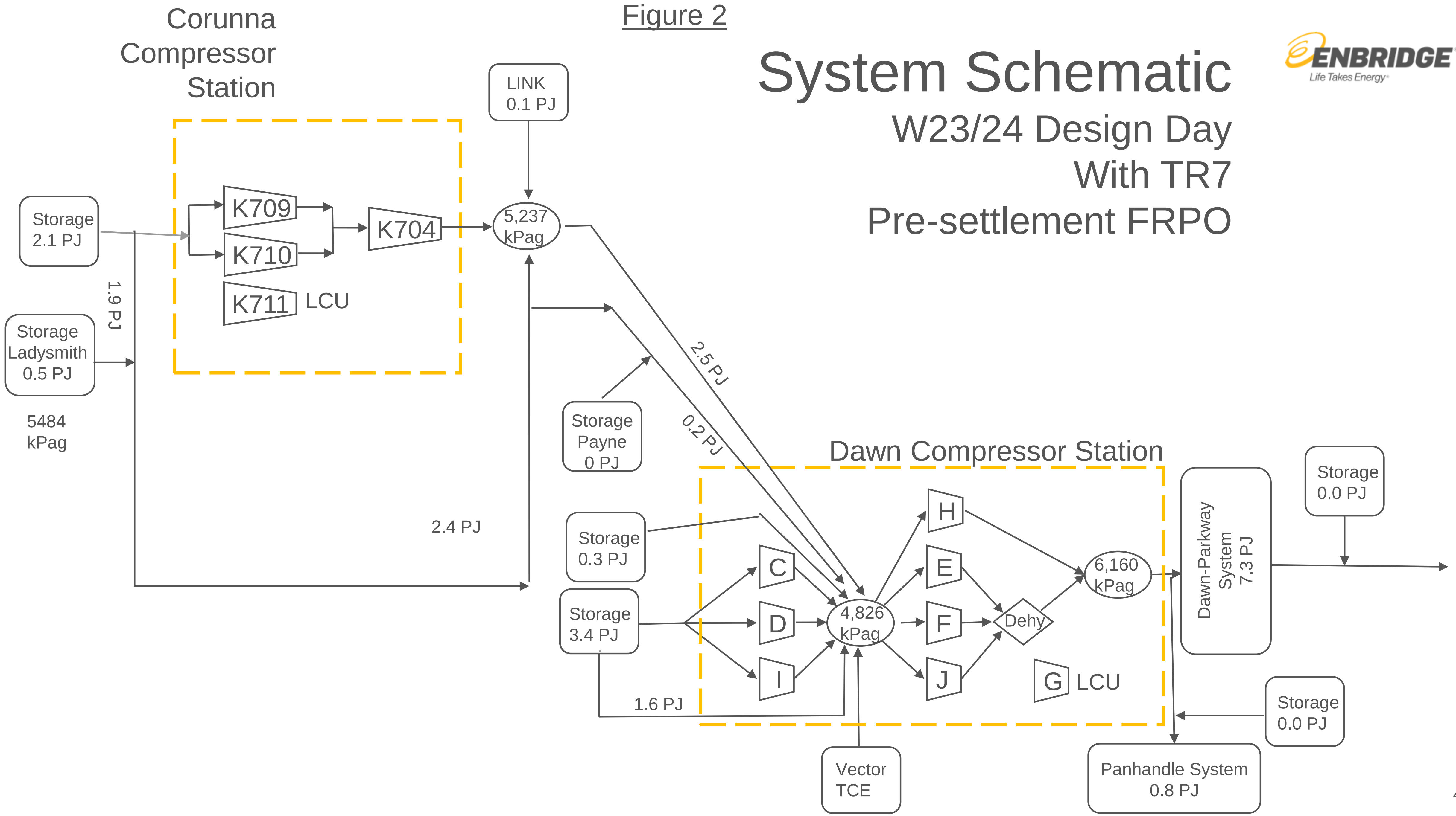


Figure 2

System Schematic
W23/24 Design Day
With TR7
Pre-settlement FRPO



ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

In JT3.4, we asked for the derivation of the 1.2% storage. While we did get actuals, we did not get an understanding of how 1.2% determined.

a) Please describe how 1.2% was determined as the standard.

b) Why should that be applied to cost-based rate making including the base rates of the EB-2022-0200 Draft Rate Order.

Response:

a) The firm daily withdrawal rights associated with market-based storage services procured by Enbridge Gas are 1.2%, which enables the utility to empty related storage space within roughly 90 days (90-day service) over the course of the winter withdrawal season. This is a standard parameter offered by many storage service providers across North America.

b) The 1.2% deliverability parameter was not used to calculate base rates in the EB-2022-0200 Draft Rate Order. The amount represents the deliverability provided by a standard market-based storage service and was used to determine the per unit cost of storage at 2024 cost-based rates that is comparable to the cost of market-based storage in response at Exhibit I.4.2-FRPO-47.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

In JT3.40, we asked for operating pressures for the 2021-2022 SCOR meter project. Please provide the MOP of all pools that can feed into the new metering without needing to move through the Corunna compression.

Response:

The following pools, and their associated MOP, are connected to the new header system constructed as part of the 2021 to 2022 SCOR meter project.

Table 1

Line No.	Pool (a)	MOP (kPa) (b)
1	Corunna	10,420
2	Coveny	8,730
3	Dow Moore	10,440
4	Ladysmith	9370
5	Mid Kimball	8,550
6	Payne	9,530
7	Seckerton	10,210
8	South Kimball	8,550
9	Wilkesport	8,830

Gas from each of the pools listed can move through the Corunna Compressor Station (CCS) with or without using compression at the CCS. It should be noted that this was also the case prior to the 2021 to 2022 SCOR meter project.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference:

Exhibit JT1.21, August 1, 2024
Exhibit I.10-Staff-45 Attachment 2, July 8, 2024

Preamble:

In the above-referenced undertaking response, Enbridge Gas provided the following calculations:

- Attachment 2, 2025 Inflation Parameter Calculations, Enbridge Gas Proposal by using a logarithmic growth rate

In the above-referenced interrogatory, Enbridge Gas provided the following calculations:

- Attachment 2, 2025 Inflation Parameter Calculations, Enbridge Gas Proposal by using an arithmetic growth rate

In Footnote #1 in the above-referenced undertaking response, Enbridge Gas stated that "the arithmetic growth rates as shown in response at Exhibit 1.10-STAFF-45, Attachment 2 is 3.61% (when rounded to 2 decimal places)."

Question(s):

a) As set out in the above-referenced interrogatory, please confirm that the results of Enbridge Gas's inflation factor methodology proposal using the arithmetic growth rate, but rounded to two decimal places (instead of one) would be:
    i. 3.82% for "Table 1: Non-Labour Component-GDP_IPI (FDD) -National" (as opposed to 3.75% logarithmic)
    ii. 3.00% for "Table 2: Fixed weighted index of average hourly earnings for all employees-Ontario" (as opposed to 2.95% logarithmic)
    iii. 3.61% for "Table 3: Resultant Values - Annual Growth for the 2-Factor IPI Formula" (as opposed to 3.55% logarithmic)

b) If any items in part a) of this question are not confirmed, please explain and provide Enbridge Gas's calculations.

Response:

a-b) Confirmed.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference:

OEB Letter on 2025 Inflation Parameters, June 20, 2024
Exhibit JT1.21, August 1, 2024

Preamble:

OEB policy is to use the logarithmic growth rate, as noted in footnotes in the Appendix to the OEB Letter on 2025 Inflation Parameters.

In the above-referenced undertaking response, Enbridge Gas provided the following calculations:

- Attachment 1, 2025 Inflation Parameter Calculations, OEB's methodology for Electricity Distribution
- Attachment 2, 2025 Inflation Parameter Calculations, Enbridge Gas Proposal by using a logarithmic growth rate

OEB staff has provided the following analysis in Table 1 and Table 2 showing the impacts of the inflation parameters on Enbridge Gas's applicable revenue requirement when rounded to both one decimal place and two decimal places, as well as using the logarithmic growth rate and arithmetic growth rate.

Table 1 - Comparison Between the OEB-Approved Methodology for Electricity Distributors and Enbridge Gas's Proposed Methodology (Using the Logarithmic Growth Rate)

	Inflation Parameters	
	Rounded to Two Decimal Places	**Rounded to One Decimal Place**
OEB-Approved 2025 Electricity Distributor Inflation Parameter	3.58%	3.6%
Proposed 2025 Enbridge Gas Inc. Inflation Parameter (using **logarithmic** growth rate)	3.55%	3.5%
Difference	-0.03%	-0.1%
Equals an approximate net impact of 0.03% on Enbridge Gas's revenue requirement, when rounded to two decimal places, and a net impact of 0.1% when rounded to two decimal places		
Enbridge Gas's Applicable Revenue Requirement ($ million)	$ 2,700.0	$ 2,700.0
Extrapolated by Enbridge Gas's response to Exhibit JT1.21, page 2, August 1, 2024 (re-filed August 19, 2024)		
Approximate net impact on Enbridge Gas's revenue requirement ($ million)	$ (0.9)	$ (2.7)

Table 2 - Comparison Between the OEB-Approved Methodology for Electricity Distributors and Enbridge Gas's Proposed Methodology (Using the Arithmetic Growth Rate)

	Inflation Parameters	
	Rounded to Two Decimal Places	**Rounded to One Decimal Place**
OEB-Approved 2025 Electricity Distributor Inflation Parameter	3.58%	3.6%
Proposed 2025 Enbridge Gas Inc. Inflation Parameter (using **arithmetic** growth rate)	3.61%	3.6%
Difference	0.03%	0.0%
Equals an approximate net impact of 0.03% on Enbridge Gas's revenue requirement, when rounded to two decimal places, and a net impact of 0% when rounded to two decimal places		
Enbridge Gas's Applicable Revenue Requirement ($ million) Extrapolated by Enbridge Gas's response to Exhibit JT1.21, page 2, August 1, 2024 (re-filed August 19, 2024)	$ 2,700.0	$ 2,700.0
Approximate net impact on Enbridge Gas's revenue requirement ($ million)	$ 0.9	$ -

Enbridge Gas stated that an amount of $2.7 million is material in the normal course of business activity, as this amount is significant enough to impact the operations of the business.

Question(s):

a) In Enbridge Gas’s view, what is the correct materiality threshold to use? Please explain.

b) Please confirm whether Enbridge Gas agrees with the values and calculations in Table 1 and Table 2 prepared by OEB staff.

c) If any of the above is not the case, please explain and update Table 1 and Table 2.

d) Please explain whether Enbridge Gas agrees with OEB staff that the “Approximate net impact on Enbridge Gas's revenue requirement ($ million)” in Table 1 and Table 2 reflects immaterial impacts on Enbridge Gas’s applicable revenue requirement. If Enbridge Gas disagrees, please explain.

e) Please explain why Enbridge Gas is planning to proceed with its proposed change to its inflation factor methodology in the following context. OEB staff acknowledges that the inflation parameters are typically rounded to one decimal place. However, OEB staff notes that when using either the logarithmic growth rate or arithmetic growth rate, Enbridge Gas’s inflation factor methodology proposal results in immaterial impacts on its revenue requirement when compared to the results of applying the OEB’s standard methodology for electricity distributors. Further, Enbridge Gas’s proposal using the arithmetic growth rate (and when rounded to one decimal place) has a $nil impact when compared to the OEB’s methodology for electricity distributors.

<u>Response</u>:

a) Enbridge Gas does not believe there is a “correct” materiality threshold in terms of calculating approved revenues (or revenue requirement) under a price cap formula. The resultant revenues are simply a function of the formula inputs.

b-c) Confirmed. Note, the $2.7 million revenue requirement for a 0.1% change to inflation was derived using a simplified calculation which remains appropriate for the inflation factors described here.

d) When comparing the OEB 2025 inflation parameters for electric utilities to Enbridge Gas’s proposed parameters for calculating inflation factor, but using the logarithmic growth rate (as per Table 1, rounded to 1 decimal place in accordance with the settlement agreement in the 2020 rate adjustment case, EB-2019-0194, Exhibit N1, Tab 1, Schedule 1, page 9), the difference between the two methodologies has a material impact ($2.7 million).

When comparing the OEB 2025 inflation parameters for electric utilities to Enbridge Gas’s proposed parameters for calculating inflation factor using the arithmetic growth rate (as per Table 2, rounded to 1 decimal place), the difference between the two methodologies is immaterial.

e) Please see response at Exhibit I.10-STAFF-45 part f), second paragraph, which is reproduced here:

While the use of the Company’s proposed inflation parameters and the parameters specified in the OEB’s methodology for electricity distributors may produce results that are materially the same, the Company believes there is still rationale for the

OEB to approve the proposed parameters. As noted at Phase 2 Exhibit 10, Tab 1, Schedule 1, page 11, paragraphs 23 and 24, and Phase 2 Exhibit 10, Tab 1, Schedule 1, Attachment 1, Section 3.2, the proposed 75/25 weighting between the non-labour and labour indexes is broadly consistent with Enbridge Gas's share of non-labour and labour costs, whereas the potentially outdated 70/30 weighting is tied to non-labour and labour costs of electricity distributors dating back to the 1990s. In addition, the proposed use of AHE is more compatible with the inflation component of price cap IR than AWE, as AHE is a direct measure of input price inflation, whereas AWE is a measure of input prices and quantity (and input quantity is already captured in the industry total factor productivity variable).

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

a) Please provide a table showing the latest forecast of customer additions for each year of the rate term and a row for cumulative revenue that will be generated from those new customers within the rate term. Please make and state assumptions as necessary.

b) Please provide a table showing the latest forecast of customer exits for each year of the rate term and a row for cumulative revenue that will be lost from those former customers within the rate term. Please make and state assumptions as necessary.

Response:

a) Please see Table 1:

Table 1
Forecast Customer Additions

Line No.	Particulars	2025	2026	2027	2028	Cumulative Revenue (1) ($ millions)
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Residential	24,511	23,653	22,550	21,471	$ 117.3
2	Non-Residential	1,223	1,112	1,011	907	$ 28.8
	Union North					
3	Residential	3,014	2,840	2,661	2,496	$ 16.4
4	Non-Residential	181	162	140	120	$ 18.1
	Union South					
5	Residential	10,912	10,477	10,069	9,704	$ 49.9
6	Non-Residential	692	635	569	502	$ 70.2
7	Total	40,533	38,879	37,000	35,200	$ 300.6

Note:

(1) Cumulative revenue based on 2024 Rates including proposed Phase 2 adjustments with high-level future year IRM adjustments for PCI and indirect overhead. Residential additions are assumed to be Rate 1, Rate M1, or Rate 01 based on rate zone, and non-residential adds are assumed to be Rate 6, Rate M2, or Rate 10 based on rate zone. Billing units for customer adds based on rate class 2024 average use and

assumed to be 50% effective in year of addition. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge as a reasonable approximation of distribution margin.

b) Please see Table 2:

Table 2
Forecast Customer Exits

Line No.	Particulars	2025	2026	2027	2028	Cumulative Revenue (1) ($ millions)
		(a)	(b)	(c)	(d)	(e)
	EGD Rate Zone					
1	Rate 1	1,742	1,759	3,928	6,125	$ (12.2)
2	Rate 6	133	133	309	483	$ (4.9)
	Union North					
3	Rate 01	298	299	567	835	$ (5.9)
4	Rate 10	2	2	3	5	$ (0.7)
	Union South					
5	Rate M1	966	974	1,839	2,716	$ (2.2)
6	Rate M2	5	5	10	15	$ (0.3)
7	Total	3,146	3,172	6,656	10,179	$ (26.1)

Note:

(1) Cumulative revenue based on 2024 Rates including proposed Phase 2 adjustments with high-level future year IRM adjustments for PCI and indirect overhead. Billing units for customers based on rate class 2024 average use and assumed to be 50% effective in year of exit. Cumulative revenue calculation includes monthly customer charge, delivery commodity charge and Union South storage charge as a reasonable approximation of distribution margin.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

Enbridge's base ICM proposal. The formula was provided at Phase 2 Exhibit 10, Tab 1, Schedule 1 page 17 of 28. Is your proposal that this is going to be the calculation or is it whatever the OEB formula is at the time? OEB has launched ICM consultation, if they adjust is that the new set of rules in future years?

Response:

Enbridge Gas's proposal for the calculation of the ICM threshold is based on the OEB's current ICM policy. If there are changes to the ICM formula through the EB-2024-0236 consultation, then Enbridge Gas expects that the OEB would also provide guidance or direction as to whether these changes should be implemented immediately, or upon a utility's next rebasing. Enbridge Gas would follow the OEB's directions in that regard. In the absence of any such direction, then Enbridge Gas would propose to use the current ICM threshold calculation until its next rebasing. Additionally, to be clear, Enbridge Gas continues to propose its modified approach to ICM in relation to initial determination within leave to construct applications (modified ACM) and modified application to ALE proposals.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

In reference to a spreadsheet for the Sept. 1st Index of Customers for non-utility storage. The total withdrawal capability net of in-franchise needs of 4.1PJ is just over 10PJ/d. There may be some reasons for this level of deliverability, but we would like an explanation.

Response:

Maximum Firm Daily Withdrawal Quantities set out in the Company's Index of Storage Customers are not specific to design day. Rather, the quantities referenced reflect contractual maximum firm daily withdrawal quantities at any time over the term of the respective contracts. In other words, you cannot simply aggregate the Maximum Firm Daily Withdrawal Quantities in the report to determine system capability on a design day, as those contractual obligations include non-peak times.

On design day, maximum withdrawal capabilities for utility and non-utility customers are consistent with the Company's pre-filed evidence. Table 1 below details Utility and Non-Utility withdrawal capabilities for the Union Rate Zones and EGD Rate Zone:

Table 1
Withdrawal Capability (PJ/d)

Rate Zone	Total	Utility	Non-Utility
Union Rate Zones	4.0	2.2	1.8
EGD Rate Zone	2.6	1.9	0.7
Total	6.6	4.1	2.5

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

Where does the 85/15 split come from?

Response:

As stated in Phase 2 Exhibit JT3.39, EGD's previous methodology was approved in 2012 and relied on storage activity to determine if the project was regulated or unregulated. As of January 1, 2024, Enbridge Gas has proposed to apply the harmonized methodology prospectively to new additions but will not adjust prior additions and investments as they have already been accounted for based on prior approved methodologies. The proposed methodology provides the following classification for all new storage assets constructed:

> Category 1 - New storage assets resulting in additional space and withdrawal capability – allocated to unregulated storage.
>
> Category 2 - New storage assets to maintain existing assets or replace existing end-of-life assets – allocated to regulated or unregulated storage, consistent with the allocation of the original asset.
>
> Category 3 - New storage assets to replace and enhance existing assets – allocated to regulated and/or unregulated storage based on the underlying project driver.

Starting with the 2024 Budget, new projects created are allocated between regulated and unregulated based on the harmonized methodology. Projects created in prior years with a budget for ongoing or trailing costs in 2024 will follow the previous methodology. Once a project is set up, the allocation between regulated and unregulated is not retroactively adjusted, so that a consistent methodology is applied throughout the life of the project. This treatment will also be applied for 2024 actuals and in future year budget and actuals, where a project was set up prior to January 1, 2024, and had an allocation applied based on the approved policy at that time.

EGD rate zone uses a group method for plant additions such that all assets that belong to a plant account are reported in that plant account without further separation or tracking at the asset pools or individual asset level. Based on gross ending plant balances between regulated and unregulated as at December 2023, the split is 85.5%

regulated and 14.5% unregulated. Enbridge Gas proposes to use an 85/15 split as the starting point for allocation of 2024 EGD actuals in relation to any Category 2 or 3 storage projects. This is consistent with Enbridge Gas's approach in the 2024 Budget.

The examples in Table 1 outline the application of the new storage asset categorizations per the harmonized methodology using the proposed 85/15 split.

On a harmonized basis in line with treatment for storage assets with the Union Gas rate zones, the allocation for storage assets in the EGD rate zone will be updated annually based on the prior year end gross plant addition actuals, following the harmonized methodology to determine the allocation between regulated and unregulated assets. EGD rate zone will track asset values for each storage pool and their associated allocation between regulated and unregulated for all new additions prospectively. Projects initiated in 2024 will apply the 85/15 split, where applicable, for the life of the project and future year projects will apply the latest updated split for that year, which is calculated at the end of the previous year. The harmonized methodology ensures a consistent approach to allocation of costs as of 2024, which is based on the underlying activities of the unregulated and regulated operations. The ending 2023 balances reflect and maintain the integrity of the approved legacy approaches through 2023. Effective January 1, 2024, the harmonized methodology is applied in a consistent manner within each respective storage pool.

Table 1
EGD Harmonized Storage Allocation Examples - EGD Assets Book Value (used for allocation)

2023 End. Bal	Regulated	Unregulated	Total
EGD	875.2	148.3	1023.5
Split	85.5%	14.5%	

Sc.1 $100 million new net addition under cat. 1
New storage assets resulting in additional space and withdrawal capability - new EGD asset
Allocated to EGD unregulated storage.

2024	Regulated	Unregulated	Total
EGD -2024 open. Bal.	875	148	1,024
New addition	-	100	100
EGD -2024 end. Bal.	875	248	1,124
Split	78%	22%	

Sc.2 $100 million new net addition under cat. 2
New storage assets to maintain existing assets or replace existing end-of-life assets – Legacy EGD asset
Allocated to regulated or unregulated storage, consistent with the allocation of the original asset.

2024	Regulated	Unregulated	Total
EGD -2024 open. Bal.	875	148	1,024
New addition	85	15	100
EGD -2024 end. Bal.	960	163	1,124
Split	85%	15%	

Sc.3 $100 million new net addition under cat. 3 a)

New storage assets to replace and enhance existing assets at the end of its useful life - Legacy EGD Asset

Allocated to regulated and/or unregulated storage based on the underlying project driver.

Assume 50% increase in capacity/ the cost of enhancement is $50 out of the total $100.

2024	Regulated	Unregulated	Total
EGD -2024 open. Bal.	875	148	1,024
New addition			
50% increase in capacity	-	50	50
remaining	43	8	50
EGD -2024 end. Bal.	918	206	1,124
Split	82%	18%	

Sc.4 $100 million new net addition under cat. 3 b)

New storage assets to replace and enhance existing assets that is not at the end of its useful life - Legacy EGD Asset

Allocated to unregulated storage

2024	Regulated	Unregulated	Total
EGD -2024 open. Bal.	875	148	1,024
New addition	-	100	100
EGD -2024 end. Bal.	875	248	1,124
Split	78%	22%	

ENBRIDGE GAS INC.

Answer to ADR Information Request

Question(s):

For the Low-Carbon Voluntary Program, can the voluntary take-up exceed the thresholds?

Response:

Yes, voluntary take-up can exceed the threshold. This was answered as part of Exhibit I.4.2-SEC-30, the relevant part of the response is reproduced here:

If there are more elections through the LCVP than available RNG supply, Enbridge Gas will attempt to procure additional RNG on short-term contracts of up to one year. Contracts longer than one year would result in the risk that Enbridge Gas could exceed the maximum bill impact threshold should LCVP customers opt out of the program in future years. If Enbridge Gas cannot procure additional RNG to satisfy the LCVP elections, the Company will offer customers an election percentage proportionately reduced for all new LCVP election requests in the year.

ENBRIDGE GAS INC.

Answer to ADR Information Request

Reference:

Draft Working Papers – Schedule 1
ADR-20-Attachment 1 (2024 Unregulated Storage Cost Allocation Calculation)

Question(s):

1. Please confirm that the $140.5M reduction to rate base in Line 1 reflects the $19M reduction to Dawn to Corunna project costs plus the $121.5M reallocation based on the 38% unregulated storage allocator.

2. Please explain what the $0.7M reduction to rate base shown in Line 2 reflects. More specifically, does this reflect the application of the 38% unregulated storage allocator to both 2024 storage replacement additions (excluding Dawn to Corunna project costs) and general plant changes.

3. Regarding the Impact Summary Tab, please advise whether the 2024 interim rates as established in Phase 1 already included the revenue requirement impacts of the Harmonized Methodology as proposed by EGI.

4. Please explain the difference between the impact summary tab and the summary filed to settlement tab.

   Also please advise:

   a) How the net underground storage plant change in Column F was derived?

   b) How the increased OM&A allocation to UREG from the settlement on storage which appears to be $5.1 or $5.2 million (assuming Phase 1 already included the proposed harmonized methodology in base rates) is reflected in Schedule 1 of the Draft Working Papers.

5. Regarding the Unreg O&M storage operations tab, please explain how the allocators were calculated. As part of the response, please explain why some of the allocators are lower (e.g., compressors) than the pre-filed evidence (Ex. 1 / Tab 13 / Schd 2 / Attch 2 / p. 8) in the context of a larger allocation of assets to the unregulated business.

6. Regarding the General Plant Allocation Factor tab, please explain why Line 11 is unchanged from the pre-filed evidence (Ex. 1 / Tab 13 / Schd 2 / Attch 2 / p. 13).

Response:

1. Confirmed.

2. This amount reflects the reduction in rate base by re-allocating regulated and unregulated 2024 storage additions to be consistent with the settlement proposal. The $0.7 million rate base reduction does represent the impact of applying the 38% unregulated storage allocator to both 2024 storage replacement additions (excluding Dawn to Corunna Project costs) and general plant changes. The rate base impact in 2024 for these additions is minimal because the in-service target dates for these additions are reflected later in Q4 2024 which results in a low average of averages impact to rate base.

3. Confirmed, Phase 1 Interim Rates already include the impacts of the Harmonized Methodology and the original forecast allocation. The Impact Summary Tab reflects the impacts of layering on Phase 2 adjustments to the overall revenue requirement.

4. The impact summary tab in provided at Attachment 1 reflects the overall revenue requirement implications of the settlement agreement. The impact summary includes each of the line items in the summary filed to settlement tab. More specifically, line 1 of the impact summary includes the reduction to regulated depreciation related to Dawn to Corunna costs reallocated to unregulated operations. Line 2 includes the reduction to regulated O&M and property taxes that are shown in the summary filed to settlement tab.

   a) This is the updated net book value change (gross plant less accumulated depreciation) for underground storage assets allocated to unregulated operations, different than the associated rate base (which is the average of averages for 2024).

   b) First confirming that the change from Unregulated Storage Cost allocation from pre-filed to settlement is an incremental $5.2 million allocated to unregulated operations; the adjustments related to lines 7, 10 & 12 are reflected in Schedule 1 Draft Working Papers in the Utility Income tab, lines 9, 10 & 13 respectively. Line 9 in Utility Income includes the $0.1 million incremental O&M plus the $1 million related to Enbridge Sustain recoveries. Line 10 includes the $2.2 million incremental depreciation allocated to unregulated operations (plus another $0.3 million reduction to regulated depreciation related to the $19 million of Dawn to Corunna costs written off). Line 13 includes the $0.1 million incremental property taxes allocated to unregulated operations.

The adjustment in line 15 of the Unregulated Storage Cost allocation represents the increase in long term debt that is theoretically allocated to Unregulated Operations (decrease in long term debt allocated to regulated rate base); the result is that for regulated cost of capital, short term debt picks up the decrease in long term debt; this is meant to be reflected in the Schedule 1 Capital Structure line 1 & 2 however Enbridge Gas has maintained a consistent Cost of Capital all through this application. In relation to the decrease in regulated rate base as a result of settlement agreement, all components (Long- and Short-Term Debt, and Common Equity) received a proportionate reduction reflecting the Settlement Agreement and reduction to Rate Base.

5. The allocators were calculated using the ratio of the ending balance of unregulated vs regulated assets by asset category. The allocator was revised from the pre-filed evidence to reflect the 2023 Dawn to Corunna additions (split as agreed to) as well as the 2024 storage asset additions using the 62%/38% spilt agreed to in the settlement. Even though there is a larger allocation of assets to unregulated assets, the 62% of regulated asset additions is still higher than the 38% unregulated asset additions in the total storage asset additions. The result is a higher increase in regulated assets ending balance compared to unregulated assets and therefore a decreased ratio between regulated vs unregulated in some instances.

6. The General Plant Allocator that was derived for pre-filed evidence was based off of 2022 actuals including specifically associated Total and Unregulated O&M. It was not Enbridge Gas's understanding that the allocator was to be updated for the O&M items as part of this calculation, but rather layering on the impacts related to unregulated storage assets specific to 2023 Dawn to Corunna and 2024 Storage Additions only, i.e. impacting line 8.

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Please see Exhibit I.ADR-20_Attachment 1.xlsx on the OEB's RDS.