K1.6

EB-2016-0186

IN THE MATTER OF The Ontario Energy Board Act.,S.O. 1998 c.15, Schedule B and in particular S.90(1) and S.36 an Appliction by Union Gas Limited for Panhandle

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VULNERABLE ENERGY CONSUMERS COALITION ("VECC") CROSS-EXAMINATION COMPENDIUM

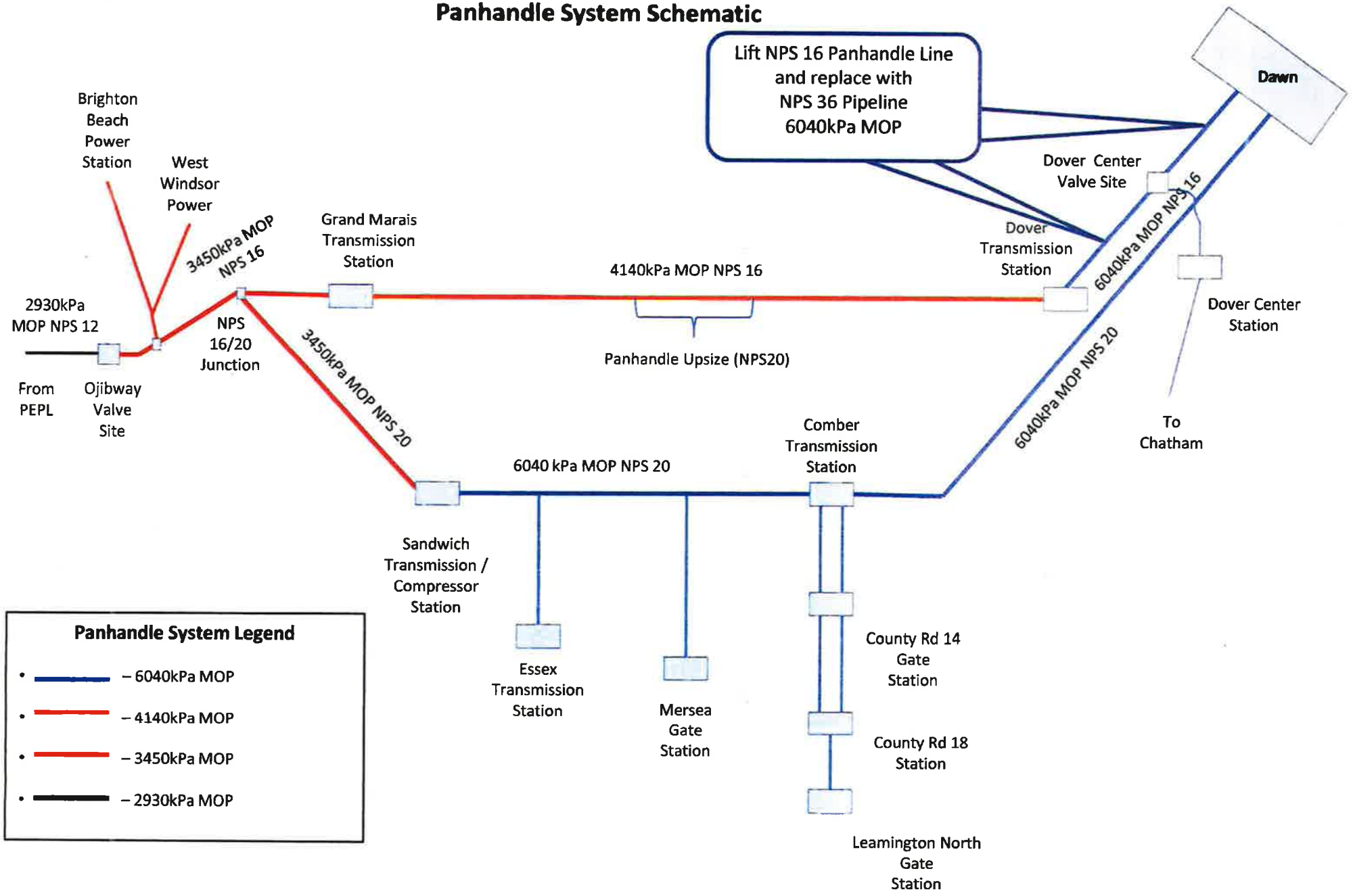
November 22, 2016

TAB 1

KT

Panhandle Reinforcement Project

Panhandle System Schematic



TOTAL ESTIMATED PIPELINE & STATION COSTS

	Mainline	Dawn M&R	Dover Centre Stn	Dover Transmission Stn	Mersea Gate Stn	
	$16,578,000	$3,958,000	$381,000	$2,162,000	$721,000	
n and Labour	$176,147,000	$17,399,000	$2,056,000	$5,362,000	$2,790,000	
ies	$28,909,000	$3,204,000	$365,000	$1,128,000	$527,000	
ing Construction	$2,321,000	$251,000	$43,000	$116,000	$50,000	
ıted Capital Costs – 2017 Construction	$223,955,000	$24,812,000	$2,845,000	$8,768,000	$4,088,000	**$26**

TAB 2

Table 5-2 – Design Day Forecast Growth

Timeframe	**Design Day Requirement (TJ/d)**
November 1, 2016 (Post Leamington Expansion[2])	565
2017 – 2021 Forecast Growth	106
2022 – 2034 Forecast Growth	99
Total 2034 Design Day Requirements on the Panhandle System	**770**

Union forecasts that residential customer attachments in the Market will increase by approximately 6000 customers between 2017 and 2021 provided enough system capacity exists. Actual and forecast residential customer attachments are shown in Table 5-3 below.

Table 5-3 – Residential Customer Attachments

	Actual				**Forecast**					
Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Number of residential attachments	1266	1051	1261	1294	1200	1200	1200	1200	1200	1200

Based on this demand forecast, future natural gas supply and facility needs can be identified, evaluated, analyzed and scheduled to meet the future growth demands on the system. The advantages of this long-term planning approach can be summarized as follows:

i. Through the identification of future growth areas, Union is more responsive to customer needs;

[2] 2016 Leamington Expansion Pipeline Project (EB-2016-0013)

Board Staff Pre-filed Question 2 b)

Has Union considered any short term supply options to serve the 48 TJ/d of unmet demand? Please provide details of the options considered.

Response:

The following is intended to supplement the response provided by Mr. Shorts at page 162 of the EB-2016-0186 Technical Conference transcript.

Union not only contemplated but has actively pursued a number of short and longer term alternatives to meet the forecasted firm service demand increases. These alternatives are detailed at Exhibit B.Staff.3 a).

In summary,

1) Union entered an open season on the Panhandle Eastern Pipeline Limited ("PEPL") system for 23 TJ/d of firm transportation capacity to Ojibway for a 5-year term commencing November 1, 2017. PEPL stated that there was insufficient capacity available to Ojibway and denied Union's request for firm transportation capacity.
2) Union issued a Request for Proposal ("RFP") to a broad range of market participants (100 in total) to secure firm delivered supply or firm transportation capacity to Ojibway starting in November 1, 2016. Union received only one response to the RFP and subsequently contracted for the full 21 TJ/d of firm delivered supply at Ojibway offered by that party for the period November 1, 2016 to October 31, 2019.
3) Union conducted a reverse open season to determine if any existing in-franchise firm customers along the Union Panhandle System did not require all or portions of their contracted firm capacity. No customers responded to the reverse open season request.
4) Union canvassed in-franchise power customers in the Windsor area to inquire about their interest in turning back all or a portion of their contracted firm capacity effective November 1, 2017. No turn back was offered to Union.
5) Other alternatives related to existing C1 transportation customers were investigated. In the end, Union purchased 21 TJ/d of firm delivered supply from the only C1 Ojibway to Dawn transportation customer contracted past November 1, 2017 as noted above. Union understands that this counterparty does not have any further firm PEPL transportation capacity to Ojibway.

Therefore, none of these alternatives will meet the needs of the 48 TJ/d noted let alone the total 106 TJ/d of incremental firm load to meet in-franchise demand for the period November 1, 2017 to November 1, 2021.

Board Staff Pre-filed Question 2 c)

Under what conditions can Union defer the proposed project in the short-term (1-3 years) until there is greater clarity on the Province's proposed cap and trade program?

Response:

The following is intended to supplement the response provided by Ms. Caillc at pages 162-163 of the EB-2016-0186 Technical Conference transcript.

Union is not aware of any conditions under which this proposed reinforcement could be deferred in the short-term.

The Proposed Project is required to serve the immediate demand of both residential and contract rate customers. Union has already been refusing incremental firm service to contract rate customers in 2016 and 2017 (and periods beyond), as a result of the constraints on the Panhandle System and, without the proposed reinforcement. Union will not be able to connect the forecasted additional general service customers (ie. new houscs in thc arca) for the winter of 2017/2018. In addition to the commercial, institutional and industrial customers who would not receive service, Union forecasts that approximately 6,000 new residential customers would not be able to receive natural gas service between the winters of 2017/2018 and 2021/2022.

As stated in Exhibit B.Staff.4 part c), Union's forecasted demands will result in the capacity from this proposed project being fully subscribed after five (5) years. It is unlikely there will be any material impact of CCAP, DSM or Cap and Trade on natural gas demand within this time frame. In addition, Union has received many letters of support from the affected municipalities, Ontario Greenhouse Vegetable Growers, the Ontario Federation of Agriculture and customers that further demonstrate the urgent need for the proposed facilities.

the introduction of the cap-and-trade program by 2020[1] (Attachment 2). This represents less than 2% of Ontario emissions.

To further demonstrate market commitment, Union is in the process of entering into binding 5-year agreements for incremental firm contract rate service served from the Panhandle Reinforcement Project beginning November, 2017. Union has, in the past, backstopped major pipeline expansions (ie. Dawn Parkway) with contractual commitments from ex-franchise customers who will be using the capacity. Although the term contract does not require customers to pay for this incremental firm capacity with any up front aid for the transmission pipeline, Union is making a significant investment to provide customers with the firm capacity that they have been asking for and it is appropriate for customers to demonstrate their commitment to the Panhandle Reinforcement Project though contractual commitments. In addition, this helps demonstrate to other ratepayers and stakeholders that the facilties are required. This 5-year commitment also ensures that customers in this area are treated in a similar fashion as those who recently received firm capacity. Those customers supported the distribution build specific to their area needs through an aid to construct charge or term contract. This approach will continue with further distribution reinforcements, the need for which Union continues to evaluate given recent requests and market growth. The 5-year contract term related to the Panhandle System Reinforcement facilities is in line with Union's projection of future required reinforcement on the Panhandle System.

Medium-term Impact:

It is Union's view that the Panhandle System once expanded in 2017, will continue to be used for at least the next 20 years. Union believes that the demand on the Panhandle System is sustainable at least over the next 20 years based on specific identified projects, reasonable generic growth, projections based on historical experience, market knowledge and the continuing economic advantage that natural gas has over alternative fuels.

Union does not expect the CCAP to change the expected use of the Panhandle System over the short to medium term for the following reasons:

- The main driver for the Project is largely due to growth in the greenhouse market, not by the residential or small commercial buildings, which is the focus of the CCAP.
- Consumer behavioural change (as identified in the government analysis in Attachment 2) is not significant in the foreseeable future.
- Even if consumer behaviour change was more significant in the short to medium term, extensive experience with DSM programs has illustrated that the reduction in consumption as a result of DSM programs is not sufficient to offset load growth in the market and the resulting need for facilities on peak day. In fact, peak day usage has

[1] "Impact Modelling and Analysis of Ontario Cap and Trade Program", EnviroEconomics, slide 12, provided at Attachment 2.

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Exhibit B.VECC.2
Page 1 of 1

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A, Tab5

a) What rate classes do Greenhouse market operators generally fall into?

b) How many customers served on the Panhandle System are currently on interruptible service?

c) How many of these customers have requested firm service?

d) What portion of the incremental demands are due to (actual or forecast) the change in service from interruptible to firm?

e) Does any hospital within the affected area currently take interruptible service?

Response:

a) Greenhouse operators fall into the following rate classes: Rate M2, Rate M4, Rate M5, Rate M7 and Rate T1.

b) Please see the response at Exhibit B.IGUA.1 f).

c) As indicated at p.3 of the pre-filed evidence for the Leamington Expansion Project (EB-2016-0013), 62 customers expressed interest in firm service and were offered a prorated share of the firm capacity available. The remaining share of the initial requested firm capacity forms a part of the forecast that supports this Project. As well, additional greenhouse load is forecasted post 2017 based on recent expansion activity in the area.

d) Please see the response at Exhibit B.APPrO.2 a).

e) There are three hospitals in the affected area that have interruptible service. The total interruptible hourly load is 2,295 m^3/hour. This represents 99.5% of the hourly gas needs for these hospitals. All three have provided letters of support for the Panhandle Reinforcement Project.

Hospital 1: Firm Hourly Quantity: 11 Interruptible Hourly Quantity: 945

Hospital 2: Firm Hourly Quantity: 0 Interruptible Hourly Quantity: 750

Hospital 3: Firm Hourly Quantity: 0 Interruptible Hourly Quantity: 600

d) The number and duration of the Panhandle System interruptions is provided in the table below:

Panhandle System Interruptions		
Winter	Number of Interruptions	Duration (in days)
2011/2012	0	0
2012/2013*	1	3
2013/2014	2	6
2014/2015	9	16
2015/2016	1	2

Note*: interruption in Winter 12/13 was called for Leamington/Kingsville only.

e) Please see the table below for Union's estimate of the cost of alternate fuel during an interruption over the past five years.

Alternative Fuel Mix	W11/12	W12/13	W13/14	W14/15	W15/16
Oil		70%	70%	70%	70%
Diesel		30%	30%	30%	30%
Propane					
Alternative Fuel Cost					
Oil		$ 22.13	$ 23.34	$ 13.54	$ 7.52
Diesel		$ 22.47	$ 24.93	$ 18.26	$ 13.44
Propane		$ -	$ -	$ -	$ -
Weighted cost of alternative fuel per GJ		$ 22.23	$ 23.81	$ 14.96	$ 9.30
Total Alternative Fuel Requirement on Peak day (GJ)		91,660	75,833	72,325	58,718
Cost of Alternative Fuel per Day of Interruption		$ 2,037,904	$ 1,805,954	$ 1,081,948	$ 545,791
Days of Interruption in Winter 14/15		2.8	5.8	15.7	2
Annual Cost of Alternative Fuel		$ 5,706,132	$ 10,474,534	$ 16,986,578	$ 1,091,582

f) The Winter 2015/2016 actual firm and interruptible design volumes for Panhandle System customers are shown in the table below. The number of customers and contract customer rate class is based on data available on March 31, 2016. Union is not able to assign general service firm and interruptible design volumes to the categories requested. Union has allocated all of the contract rate customers to the Small Industrial/Large Industrial and Power Generation categories.

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EB-2016-0186
Exhibit B.BOMA.3
Page 1 of 2

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Exhibit A, Tab 5, p.1-21

a) Why is London Airport data used to model the design day degree days rather than the Windsor airport, which should be more representative of the temperature in this case (Kingsville, Leamington) of the Panhandle system market?

b) Please confirm the degree day differences between the London and Windsor airports and winter temperature difference between London airport and Kingsville and Leamington and Windsor, and between Windsor airport and Kingsville and Leamington.

c) What would design day capacity be if measured at (i) Windsor; or (ii) a blend of London/Windsor?

d) Please show the growth forecast over the 2017-2021 period, and for the period past 2022 for each component of the market, including:

i. East of Dover (Chatham Kent);
ii. Leamington;
iii. Kingsville;
iv. Lakeshore;
v. Tecumseh;
vi. West Windsor cogen;
vii. Brighton Bruce Power;
viii. City of Windsor;
ix. Other.

Response:

a) London Airport weather is used to determine the design degree days for the entire Union South delivery area as it is centrally located within the delivery area. London Airport data provides a consistent weather standard by which all of the Union South distribution, transmission, and storage facilities are designed to serve.

b) On average, Windsor Airport is 1.7 degree days warmer than London Airport however Windsor has experienced colder single day temperatures than London. For example, the coldest degree day during the winter of 2013/2014 occurred on January 16, 2014 where Windsor experienced a 43.5 Design Day ("DD") while London experienced a 41.5 DD. The 43.5 degree day is higher than Union South design of 43.1 DD. Union does not have weather data specifically for Leamington or Kingsville.

c) Using Windsor degree days rather than London degree days actually increases the DD demand for the Panhandle System. Union completes a linear regression of the actual measured volumes into the Panhandle System with respect to the degree day for each day of the winter season. Using warmer degree days with the same measured volumes, increases the slope of the linear regression which when extrapolated to the design degree day results in increased DD demand. Also, the highest historical degree day at Windsor Airport is higher than that measured at London Airport which would increase the degree day demand even more (see part b) above).

d)

	Forecast Growth by Region (TJ/Day)				
Area/Customer	2017	2018	2019	2020	2021
Chatham-Kent	1	6	10	12	13
Leamington/Kingsville	38	45	51	57	63
Lakeshore	0.3	0.3	0.3	0.3	0.3
Tecumseh	1	1	1	1	1
Windsor	18	21	23	26	29
West Windsor Cogen	-	-	-	-	-
Brighton Beach Power	-	-	-	-	-
Total	58	73	86	96	106

Union does not have a detailed forecast after 2021, but assumes generic greenhouse growth of 6 TJ/day (5 TJ/day in Leamington/Kingsville and 1 TJ/day in Chatham-Kent) as well as 1 TJ/day of generic residential demand in Windsor.

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Exhibit B.BOMA.5
Page 1 of 3

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Exhibit A, Tab 5, p.17

a) Did Union's reverse open season apply to the two long-term C1 customers as well? If not, please explain why not.

b) Please identify the greenhouse operations that have chosen to expand in Ohio.

c) Please describe the extent to which CO_2 produced by natural gas consumption at the greenhouse can be utilized within the greenhouse. Please provide a quantitative analysis.

d) Please provide the amount of IT service on the Panhandle system in each year since 2012 (inclusive).

e) Please indicate what components of the existing and forecast demand off the Panhandle system are:

i. heat sensitive (residential, commercial);
ii. heat sensitive (greenhouse);
iii. non-heat sensitive – electricity generation; Brighton Beach; West Windsor;
iv. non-heat sensitive – commercial (eg. commercial/institutional hot water; industrial);
ii. in each case, please state the sector or subsector volume/contract demand and the extent to which it is heat sensitive.

Response:

a) No, the reverse open season noted did not apply to the long term, firm C1 Ojibway to Dawn transportation contracts. Since the firm C1 Ojibway to Dawn transportation contracts are not included in the Panhandle System design on a Design Day, Union did not offer any turn back to its firm C1 transportation customers. As noted in Exhibit B.Staff.3 a), Union has secured a delivered service to Ojibway from one of the C1 firm transportation shippers. That shipper continues to hold its C1 Ojibway to Dawn transportation capacity with no immediate intention to turn the capacity back.

b) Within the last 18 months there are two operations that have chosen to expand in Ohio, rather than in the Leamington area.

NatureFresh Farms has indicated they will spend $250 million to develop 175 acres in Ohio. Just over 15 acres is in production today and 45 acres will be producing product by the end of 2016.

GoldenFresh is currently building 20 acres as phase 1 of a 4-phase plan. The current plan is to build 100 acres over 7 to 10 years

Union's Greenhouse Account Managers have been informed by two other greenhouse operators that they are reviewing Ohio as a possible location to expand their operations.

c) CO2 is one by-product of burning natural gas. A greenhouse operator will capture the CO2 using a flue gas condenser that is attached to the flue of the unit burning the natural gas. The captured CO2 gas is then fed back to the greenhouse. Growers can control the amount of CO2 that is released to the plants via control systems. Typically, during the daylight hours, more CO2 is needed for plant growth. A natural gas boiler will, on average, produce 2 kilograms of CO2 per m^3, of natural gas burned. On average, a greenhouse will require 100 kilograms of CO2 per acre. Increased CO2 levels can shorten the growing period by 5-10%, and improve crop quality and yield. The increased yield is a result of increased numbers of plants and faster flowering per plant.

It is important to note that without a CO2 by-product, a grower would have to purchase CO2 as the ambiant environment does not provide the needed amount for ideal production. For further information please see the following website.

http://www.omafra.gov.on.ca/english/crops/facts/00-077.htm

d)

Panhandle System Interruptible Volumes (from Contracts as of March 31 of a given year)	
Year	Panhandle IT (TJ/d)
2012	170.1
2013	170.1
2014	169.2
2015	136.2

e)

Cumulative (TJ/Day)	W 15/16	W 16/17	W 17/18	W 18/19	W 19/20	W 20/21	W 21/22
Heat Sensitive (residential)	294	298	300	302	304	306	309
Heat Sensitive (commercial)							
Heat Sensitive (greenhouse)	41	74	112	124	135	143	150
Heat Sensitive (industrial)	49	49	67	68	68	68	68
Non-heat Sensitive (electricity generation)	130	130	130	130	130	130	130
Total	514	551	609	624	637	647	657

Note: for the purposes of planning, all contract load is accumulated into one group. The result is that the contract rate demand as modeled (as a whole) is heat sensitive.

TAB 3

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 3, p. 8, Table 3-1

Union has provided in-franchise bill impacts (Table 3-1) using a 20-year useful life and OEB approved depreciation rates.

a) Has Union informed its M4, M7, T1 and T2 customers about the bill impacts under the two scenarios (20-year depreciation versus OEB approved depreciation rates)? If no, why not?

b) Did Union consider a different useful life such as 30 years for calculating revenue requirement and resulting rate impacts? If no, why not?

Response:

a) Please see Exhibit B.Staff.4 b).

b) No. Union did not consider a different useful life other than the 20 years as proposed. The decision to use 20 years is based on management judgement and the rationale is detailed at Exhibit A, Tab 3, pp. 7-8.

As shown at Exhibit A, Tab 8, Schedule 1, line 11, the 2017 and 2018 revenue requirements associated with the Project based on Union's proposal to depreciate the assets over a 20-year useful life are approximately $32.2 million ($5.0 million and $27.2 million respectively).

At Exhibit A, Appendix B, Schedule 1, line 11 Union has provided the 2017 and 2018 revenue requirements for the Project based on Board-approved depreciation rates. The 2017 and 2018 revenue requirements are $18.0 million ($0.3 million and $17.7 million respectively).

Accordingly, the change in revenue requirements for 2017 and 2018 between Union's proposal and Board-approved depreciation rates is a reduction of $14.2 million. Should the Board reject Union's proposal to depreciate the Project assets over a 20-year useful life, Union will address the impacts of the Board's decision as part of its 2019 rebasing application.

The proposal to change the depreciation rate now enables the recovery of the investment from all customers rather than expecting to recover the investment later from the customers that remain on the system.

The benefit of reducing the depreciation period now to 20 years is that it recovers the investment from as many customers as soon as possible which will minimize the future rate impact to customers. Further, as discussed above Union would also have the option of decreasing upstream transportation commitments or delivered supply at Ojibway to mitigate the decreasing demand requirements on the Panhandle System. This would result in a higher utilization of the Project and an efficient use of the asset.

Please see the response at Exhibit B.Staff.3.

TAB 4

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 3, p. 5-6

Union has referred to the government's Cap and Trade Program and the introduction of the 5 year Climate Change Action Plan (CCAP). Union notes that the details of the CCAP appear to include putting restrictions on the use of natural gas in Ontario in the next 15 to 35 years.

a) Has Union contacted its large and commercial customers that have requested additional capacity on the Panhandle System after the government's introduction of the CCAP?

b) Have these large customers expressed any uncertainty as a result of the introduction of the CCAP?

c) Have any of the customers revised their natural gas needs or expansion plans as a result of the CCAP? Please provide a detailed response.

d) How are the greenhouse operators going to be impacted as a result of the CCAP? Does Union expect a reduction in demand from greenhouse operators as a result of the CCAP in the next 10 to 15 years?

Response:

a) Union continues to have discussions with customers as to the impact of the Cap and Trade program and the Climate Change Action Plan ("CCAP"). Union has had customer meetings for all large industrial and commercial customers where CCAP was discussed. Customers were provided the financial impacts expected based on the required actions that the utility has to take to implement this program. These meetings included the customers who requested incremental firm capacity on the Panhandle System. The presentations from those meetings can be found below.

https://www.uniongas.com/~/media/business/communication-centre/training/May%202016%20Large%20Industrial%20Update/Cap_and_Trade.pdf?la=en

https://www.uniongas.com/~/media/business/communication-centre/training/June%202016%20Customer%20Meeting%20Presentations/Cap%20and%20Trade.pdf?la=en

b) Some customers have expressed uncertainty about the CCAP. Union has communicated the expected impact to their natural gas costs. However, in spite of the uncertainty surrounding CCAP and incremental costs associated with Cap and Trade, customers are requesting more firm service and see the economic value of natural gas.

c) Some customers have indicated a revision to their natural gas needs or expansion plans as a result of Cap and Trade and the CCAP. None of the items below were in Union's forecast, and none of these impact the Panhandle System. One customer is in Northern Ontario and the others are all in Sarnia:

- Customer 1 indicated they would not have invested in another Ontario plant had they known about Cap and Trade and the additional cost of feedstock. Additional capacity that was being considered is no longer being considered.
- Customer 2 has postponed on site co-generation.
- Customer 3 had postponed on site co-generation.
- Customer 4 has plant viability concerns post 2019 and Cap and Trade does not help.
- Customer 5 has put DSM projects on hold awaiting CCAP details.
- Customer 6 put on hold micro turbine projects to generate electricity for electric vehicles ("EV") charging stations.
- Customer 7 wants to expand in Ontario but high electricity prices are a barrier and believe costs will get higher with Cap and Trade and CCAP.

d) The CCAP has identified programs that target the greenhouse sector and should customers avail themselves of these programs, there is an expected reduction in GHG emissions for those customers. The specific details as to what these programs provide are still being developed.

However, the greenhouse sector continues to grow and request additional natural gas as a result of more acreage being developed by greenhouse operators. In the Ontario Greenhouse Vegetable Growers letter of support (Exhibit A, Tab 5, Schedule 2, p.5) for the Panhandle Reinforcement Project, the association states: *"We expect this growth will continue into the future and predict the sector could grow by 750 acres over the next 5 years, contributing an additional $1.3 billion to the Ontario economy and supporting over 3,000 new jobs. In order for this growth and development to be realized sufficient access to natural gas infrastructure will be required."*

Please see the response at Exhibit B.Staff.4 c).

TAB 5

Table 8-3
Comparison of Board-Approved vs. Proposed 2018 Project Cost Allocation Factors

Line No.	Rate Class	Board-Approved Allocation ($10^3m^3/d$) (a)	Board-Approved Allocation (%) (b)	Proposed Allocation ($10^3m^3/d$) (c)	Proposed Allocation (%) (d)	Variance ($10^3m^3/d$) (e) = (c-a)	Variance (%) (f) = (d-b)
1	Rate M1	3,789	21%	5,623	40%	1,834	19%
2	Rate M2	1,289	7%	1,915	14%	627	7%
3	Rate M4	1,174	7%	1,968	14%	793	8%
4	Rate M5	18	0%	30	0%	12	0%
5	Rate M7	338	2%	570	4%	232	2%
6	Rate T1	1,023	6%	678	5%	(345)	-1%
7	Rate T2	7,560	42%	3,202	23%	(4,357)	-19%
8	Total In-franchise	15,191	85%	13,986	100%	(1,204)	15%
9	Rate C1	2,264	13%	-	0%	(2,264)	-13%
10	Rate M16	473	3%	-	0%	(473)	-3%
11	Total Ex-franchise	2,737	15%	-	0%	(2,737)	15%
12	Total	17,927	100%	13,986	100%	(3,941)	

Union's proposed allocation of the Project-related costs results in a decrease in the allocation factor of Rate T1, Rate T2, Rate C1 and Rate M16 and an equal and offsetting increase to the allocation factors of the remaining Union South in-franchise rate classes. There is no impact to Union North rate classes related to Union's proposed cost allocation compared to the Board-approved cost allocation.

The allocation to Rate T1 and Rate T2 decreases as a result of the difference between the Board-approved allocation factor based on the combined Panhandle System and St. Clair System Design Day demands and the proposed allocation based on the Design Day demands on the Panhandle System only. The Rate T1 and Rate T2 Design Day demands on the St. Clair System are proportionately greater than the updated Design Day demands on the Panhandle System. By excluding the Design Day demands on the St. Clair System in the allocation of the Project costs, the Rate T1 and Rate T2 allocation decreases by 1% (from 6% to 5%) and 19% (from 42% to 23%), respectively. The Rate T1 and Rate T2 Design

the proposed allocation is provided at Table 8-8. The detailed comparison of the Board-approved and proposed cost allocation of the 2018 Project costs, net of the incremental Project revenue, is provided at Exhibit A, Tab 8, Schedule 5.

Table 8-8
Comparison of Board-Approved and Proposed
2018 Project Cost Allocation Impacts

Line No.	Particulars ($000's)	Board-Approved (a)	Proposed (b)	Difference (c) = (b - a)
	In-franchise South			
1	Rate M1	4,978	10,553	5,576
2	Rate M2	1,927	3,824	1,897
3	Rate M4	1,177	3,143	1,966
4	Rate M5	(2)	32	34
5	Rate M7	254	796	542
6	Rate T1	1,520	1,252	(268)
7	Rate T2	11,818	6,316	(5,502)
8	Other	8	8	-
9	Total In-franchise South	21,680	25,925	4,245
	Ex-franchise			
10	Rate C1	3,594	79	(3,514)
11	Rate M16	714	(16)	(731)
12	Other	286	286	-
13	Total Ex-franchise	4,595	350	(4,245)
14	Total In-franchise North	(667)	(667)	-
15	Net Revenue Requirement	25,607	25,607	-

As a result of Union's proposed allocation, the net revenue requirement results in: (i) an increase of approximately $26.0 million allocated to Union South in-franchise rate classes, (ii) an increase of approximately $0.4 million allocated to ex-franchise rate classes and (iii) a decrease of approximately $0.7 million allocated to Union North in-franchise rate classes, per Table 8-8, column (b).

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Exhibit B.Staff.6
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UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 8, p.6-7; Exhibit A, Appendix B

Union has proposed to allocate the Panhandle System demand costs related to the project in proportion to the firm South in-franchise Panhandle System design day demands, updated to include the incremental firm project design day demands. Union has noted that with the addition of the significant project costs related only to the Panhandle System and no change to the cost of the St. Clair System, the use of the combined system for cost allocation purposes no longer reflects the costs to serve the customers on each transmission system. Union has indicated that its proposed interim allocation of project costs based on the Panhandle System design day demands better reflects the principle of cost causality during the remainder of the IRM term.

a) Is it the opinion of Union that the cost allocation methodology should be updated whenever there is a major change in the demand profile during an IRM term?

b) Did Union's IRM Settlement Agreement (EB-2013-0202) envision a change in the cost allocation methodology for large capital projects during the IRM term?

c) Please provide the total volumes segmented by rate class (including Rate C1 and M16) that will flow on the Panhandle System once the proposed project is in service. Please also provide the direction of the volumes under each rate class.

Response:

a) Union reviews the appropriateness of the EB-2011-0210 (2013 cost of service) Board-approved cost allocation methodology with each capital pass-through project application during the IRM term. The Panhandle Reinforcement Project is Union's first project that meets capital pass-through treatment criteria that Union has proposed cost allocation methodology other than Board-approved. Union's Brantford to Kirkwall/Parkway D, 2016 Lobo C and Hamilton to Milton, and 2017 Dawn Parkway Project applications all used Board-approved cost allocation methodologies and all included changes in the demand profile.

b) Yes. Union's IRM Settlement Agreement (EB-2013-0202) approved by the Board does provide the opportunity for a cost allocation methodology other than Board-approved. The IRM Settlement Agreement established eight criteria for a project to qualify for capital pass-

through treatment. The major capital additions criteria vii) on page 34 of the Settlement Agreement states:

"Subject to direction otherwise from the Board, Union would allocate the net revenue requirement using the 2013 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during the review of the project, or its rate impacts, by the Board;"

c) The Panhandle Transmission System Forecast Design Day demands for Winter 2017/2018 are shown in the table below.

Panhandle Design Day Demands (Winter 2017/2018)			
In franchise Rate Class	Panhandle Design Day Demand	Panhandle Design Day Demand	Direction
	(10^3m^3/day)	(TJ/day)	
M1 / M2	7687.5	297	Westerly
M4 / BT4	2035.5	79	Westerly
M5 / BT5	284.8	11	Westerly
M7 / BT7	1191.7	46	Westerly
T-1	1121.4	43	Westerly
T-2	3808.3	147	Westerly
Total	16129.2	623	Westerly

Panhandle Transportation Contracts (Winter 2017/2018)			
Ex-franchise Rate Class	Contracted Volume	Panhandle Design Day Demand	Direction
	GJ/d		
C1	21016	0	Easterly
M16 (from Pool)	11760	0	Easterly
Union Supply (1)	58028	58028	Easterly

(1) As per Exhibit B.Staff.3 Attachment 1

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UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Exhibit A, Appendix B, Schedule 2

Why is Sarnia Industrial demand lumped in with Ojibway System Demand? What was the rationale for combining them? Please explain the project-induced large increase in M4 design day demand using current Board approved methodologies from 929 to 1,040 10^3m^3/day.

Response:

The Panhandle System and St. Clair System are combined and functionalized as Ojibway/St. Clair Transmission because both systems provide transportation opportunities for ex-franchise customers between the river crossings west of Dawn and the Dawn Compressor Station. The combined system costs are used to set a common cost-based Rate C1 long-term firm transportation rate for service between Dawn and St. Clair, Ojibway and Bluewater.

The increase in Rate M4 Design Day demands is being driven by the incremental Rate M4 demands being served as a result of the Project. As described at Exhibit A, Tab 5, p. 4, Union has received a large number of requests for new firm service and for conversion of existing Rate M5A interruptible service to firm Rate M4 service. The 2013 Board-approved Rate M4 Panhandle System Design Day demands of 929 10^3m^3/d are increasing by 696 10^3m^3/d in 2017 and an additional 343 10^3m^3/d in 2018 as a result of the Project. This total increase of 1,039 10^3m^3/d, results in total Rate M4 Panhandle System Design Day demands of 1,968 10^3m^3/d by 2018.

the combined Panhandle System and St. Clair System from $0.035 GJ/d to $0.147 GJ/d (or 323%). The comparison of average unit rates is shown in Table 8-5.

Table 8-5
Average Unit Rate of the Panhandle System and St. Clair System Including Project Cost

Line No.	Particulars	Current Approved (1)	Project Update (2)	Total Including Project	Change
		(a)	(b)	(c)	(d) = (b / a)
1	Ojibway/St. Clair Demand Costs ($000's)	7,089	28,992	36,081	409%
2	Maximum day demand	15,188	2,739	17,927	18%
	Monthly Demand per Unit ($/$10^3$m^3/d/mo)				
3	Ojibway/St. Clair Demand (line 1 x 1000/line 2/12)	38.89	882.08	167.72	331%
4	Contingency Demand	1.09	-	1.09	0%
5	IRM Adjustments	(0.15)	-	(0.15)	0%
6	Total Rate C1	39.83	882.08	168.66	323%
7	Total Daily Demand/Average Unit Rate ($/GJ/d) (line 6 x 12/365/37.75)	0.035	0.768	0.147	323%

Notes:
(1) Per Table 8-4.
(2) Project update Ojibway/St. Clair demand costs per Table 8-7.

Given the change in the total average unit cost of the Panhandle System relative to the St. Clair System, which has remained unchanged as a result of the Project, it is not reasonable to update the common Rate C1 long-term rate between Dawn and Ojibway, St. Clair and Bluewater for the remainder of the IRM term. The current Board-approved methodology was reasonable when the two systems had similar costs per unit of demand. However, the addition of the Project costs creates a large difference in the cost per unit of demand between the two systems, which no longer reflects the costs to serve the St. Clair System or ex-franchise Rate C1.

Further, the firm long-term ex-franchise Rate C1 demands do not require the Project facilities on Design Day. The Panhandle System is a westerly peaking system on Design Day with a portion of in-franchise demands being served easterly from gas imported at Ojibway. The Design Day demands that flow westerly from Dawn are all required to serve Union South in-franchise demands. While Union offers a service from Dawn to Ojibway, St. Clair and Bluewater, there are no long-term firm ex-franchise contracts that flow westerly from Dawn under Rate C1. Union's firm long-term Rate C1 contracts flow easterly to Dawn and are not considered on Design Day because ex-franchise customers have no contractual obligation to supply gas to Union's system. To the extent ex-franchise customers use their contracted capacity on Design Day, the demands would flow easterly to Dawn (counter flow), based on the Rate C1 long-term firm transportation contracts (from Ojibway to Dawn).

4.2 Rate M16 Transportation Charges

Rate M16 customers provide a contribution to the recovery of Panhandle System costs through the Rate M16 west of Dawn demand rate. The demand rate is set equal to the Rate C1 long-term firm transportation rate between Dawn and Ojibway, as calculated in Table 8-4. This rate design recognizes that storage pool operators located west of Dawn use the Panhandle System to transport gas to and from their storage pool.

Consistent with Rate C1, Union does not consider Rate M16 west of Dawn contracted capacity on Design Day, as the customer has no contractual obligation to supply gas to Union's system. If Rate M16 transportation volumes were to flow on Design Day, it is expected they would be counter flow to the Design Day requirements of the Panhandle System based on the winter operations of the customer.

4.3 In-franchise Benefit of Storage and Transmission Margin

During a cost of service proceeding, any forecast incremental revenue for ex-franchise storage and transportation services greater than the allocated costs is credited to in-franchise customers through Union's rate design process. In Union's 2013 Cost of Service, the ex-franchise transportation margin credited to in-franchise customers was approximately $9.6 million, of which approximately $3.4 million was related to short-term and long-term transportation on the Panhandle System and St. Clair System.

If Union were to increase the firm long-term Rate C1 demand rate by 323% (per Table 8-5), it is unlikely that ex-franchise customers would continue to contract for the same level of firm long-term service on the Panhandle System and St. Clair System. If Union were to use the Board-approved methodology, Union South in-franchise customers would receive a reduced cost allocation during the IRM term, which would not be supported by incremental firm long-term ex-franchise Rate C1 revenue. Accordingly, Union is proposing to not update the Rate C1 long-term firm transportation rate for the Project costs.

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Exhibit JT1.12
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UNION GAS LIMITED

Undertaking Response
To Mr. Quinn

TO CONFIRM THE CALCULATIONS IN FRPO 3B, QUESTION 7 OF EXHIBIT CT1.2

Union confirms the total C1 contracted volumes between Nov 1, 2012 and Jan 31, 2015 was 87.7 TJ/d during all months and not just the winter months.

Combining the C1 contracted volumes with the Gas Supply firm transportation capacity of 60 TJ/d results in a total C1 and Gas Supply commitment of 147.7 TJ/d in the winter and summer period up to the start of 2016. **This is no longer appropriate as the planning assumption for the Panhandle System has changed as described below.**

The maximum summer and winter capacity to be accepted at Ojibway on a firm basis is determined based on available market and facility/system capability. The available market at Ojibway is calculated based on an average of the lowest demands for 20 days of each month. This average value is compared each month across a 5 year timeframe to determine a reasonably available market.

The minimum demand profile of the market in the Windsor area, which determines the amount of firm receipts Union can accept at Ojibway, has declined for both summer and winter in 2016 and beyond, but has not lowered Design Day demands. This is due to an electric generator moving from a self-dispatch operation to a market dispatch operation during 2016. Prior to this, this electric generator ran 5 to 6 days per week, and since that time has operated only 12 days in the last 4 months.

The expected load profile going forward is the primary reason for the limitation of Ojibway receipts at 115 TJ/d in the summer and 140 TJ/d in the winter.

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Exhibit B.BOMA.9
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UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid: response assumes, Exhibit A, Tab 8, p.12

Please explain how the current rate design process provides in-franchise customers with a benefit, if any, from ex-franchise transmission margin generated. What is the relevance of the benefit provided, if any, to the issue of cost allocation.

Response:

Union's current rate design provides a benefit to in-franchise customers related to ex-franchise storage and transportation revenue that is greater than allocated ex-franchise storage and transportation costs. In Union's 2013 cost of service proceeding (EB-2011-0210) approved by the Board, in-franchise customers' rates were reduced by approximately $9.6 million related to ex-franchise transmission margin (including $3.4 million associated with the Panhandle System and St. Clair System) and $4.6 million related to ex-franchise storage margin.

The ex-franchise transmission margin is relevant to cost allocation because the margin is calculated as the difference between the forecasted revenue and the allocated costs for each ex-franchise rate class. To the extent there is ex-franchise revenue as part of the cost of service proceeding, in-franchise customers will receive the same net benefit either by way of a reduction to the allocated in-franchise costs or a reduction to in-franchise rates through the margin credit.

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UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Ibid: response assumes, Exhibit A, Tab 8, p.16

In Union's 2013 cost of service, of the $3.4 million excess incremental revenue over allocated costs related to long-term/short-term C1 forecast revenue allocated costs, how much was from the Panhandle system; how much from the remainder of Panhandle/St. Clair? What was the actual excess revenue over cost (in Panhandle) of the last five years, and how was that accounted for?

Response:

Of the $3.4 million ex-franchise transportation margin credited to in-franchise customers in Union's 2013 cost of service (EB-2011-0210), $0.7 million is related to the Panhandle System and $2.7 million is related to the St. Clair System. The $3.4 million of ex-franchise transportation margin is related to Rate C1 and Rate M16 services. The detail of the ex-franchise transportation margin for the Panhandle System and St. Clair System is provided at Attachment 1, p.1.

The actual Rate C1 and Rate M16 revenue associated with the Panhandle System from 2011 to 2015 is provided at Attachment 1, p.2. Union does not maintain the cost detail required to calculate the actual ex-franchise transportation margin of the Panhandle System outside of a cost of service forecast. Rate C1 and Rate M16 revenue is included in the calculation of utility earnings, which is subject to sharing with ratepayers during Union's IRM term, as per Union's 2014-2018 IRM Settlement Agreement (EB-2013-0202).

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UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Reference: Exhibit A, Tab 8, Schedule 2

Why is the Project Allocation Factor for T2 reduced from forty-four percent (2013 April) to twenty-four percent and twenty-three percent (in 2017 and 2018, respectively)?

Response:

The 2013 Board-approved cost allocation methodology includes an allocation to ex-franchise Rate C1 and Rate M16 based on firm contracted demands and an allocation to in-franchise rate classes in proportion to the combined Panhandle System and St. Clair System Design Day demands. Union's proposed allocation factors use only the 2013 Board-approved Panhandle System Design Day demands updated for the incremental Project Design Day demands. The decrease in the allocation for Rate T2 from 44% to 24% and 23% in 2017 and 2018 respectively, is a result of removing the ex-franchise firm contract demands and the St. Clair System Design Day demands from the Board-approved allocation methodology, net of any increase related to the incremental Panhandle System Design Day demands added to the proposed allocation factors.

TAB 6

UNION GAS LIMITED
Summary of Ex-Franchise Revenue Associated with the Panhandle System and St. Clair System

Line No.	Particulars ($000s)	2013 Board-Approved (1) (a)	2013 Actuals (2) (b)	2014 Actuals (2) (b)	2015 Actuals (2) (b)
	Panhandle System				
1	C1 Long-term Transportation	1,197	1,368	1,463	1,144
2	C1 Fuel	164	-	-	-
3	M16	204	150	190	208
4	Short-term and Interruptible Transportation	1,557	742	2,715	1,173
5	Total Panhandle System	3,122	2,259	4,368	2,525
	St. Clair System				
6	C1 Long-term Transportation	2,000	327	786	710
8	M16	330	441	348	314
9	Short-term and Interruptible Transportation	808	3,972	3,721	2,665
10	Total St. Clair System	3,139	4,741	4,855	3,689
11	Total Panhandle System and St. Clair System	6,261	7,000	9,223	6,214

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 40.
(2) 2013-2015 actual revenue excludes customer supplied fuel.

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Exhibit B.VECC.10
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UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition (VECC)

Reference: Exhibit A, Tab 8, p.16

a) Please provide the ex-franchise transportation margins for 2013 through 2015. Please also provide the amount of margin that was credited to in-franchise customers and the amount for each year related to Panhandle and St. Clair Systems.

b) Is a margin forecast built into current rates and if so what is that amount.

Response:

a) The amount of ex-franchise transportation margin included in 2013-2015 rates is based on Union's 2013 Cost of Service. The ex-franchise transportation margin credited to in-franchise customers was $9.6 million, of which approximately $3.4 million is related to short-term and long-term transportation on the Panhandle System and St. Clair System. The detail of the $9.6 million of ex-franchise transportation margin included in in-franchise rates is provided at Attachment 1. The detail of the ex-franchise transportation margin for the Panhandle System and St. Clair System is provided at Exhibit B.BOMA.11, Attachment 1, p. 1.

b) Please see part a).

UNION GAS LIMITED
Summary of Ex-Franchise Transportation Margin Included in 2013-2015 In-Franchise Rates

Line No.	Particulars ($000s)	2013 Approved Forecast Revenue (1) (a)	2013 Approved Allocated Cost (2) (b)	Total Margin Included in 2013-2015 In-Franchise Rates (c) = (a - b)
	Long-Term Transportation			
1	M12 Long-term Transportation	120,604	125,384	(4,781)
2	M12-X	13,896	11,623	2,272
3	F24-T	359	359	0
4	M12 Fuel	22,674	22,673	1
5	C1 Long-term Transportation	6,954	1,669	5,286
6	C1 Fuel	626	632	(6)
7	M13	411	211	200
8	M16	736	451	286
9	Heritage Pool M16 Transmission Charge (3)			56
10	Total Long-Term Transportation	166,260	163,002	3,314
	Short-Term Transportation			
11	Short-term Transportation	11,067	5,843	5,224
12	Other Transactional	1,067	-	1,067
13	Total Short-Term Transportation	12,134	5,843	6,291
14	Total Ex-franchise Transportation Margin	178,394	168,844	9,605

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, p. 9 - 11, column (g).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 14, p. 9 - 11, column (e).
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 39, line 4.

TAB 7

to 2021) = $(212), 40 years = $(205) to 2022) = $(239), 40 years = $(232) column is the NPV of the Capex and O&M.	5 Yr Capex $ 265 6 Yr Capex $ 305	A J cost to maintain 16" over 40 yrs ~$16	01-Nov-17	"Graham". Install approximately 12 km NPS 6 Loop Station ("McCormack") Capex ~$ 40 million
loop the existing NPS 20 Panhandle between r first 5 years + $28 for Yrs 6 to 40 to 2021) = $(224), 40 years = $(222) to 2022) = $(251), 40 years = $(248) column is the NPV of the Capex and O&M.	5 Yr Capex $ 264 6 Yr Capex $ 304	Maintain 16" over 40 years ~$ 16	01-Nov-17	Same as Proposed Project above
d le NPS 16 pipeline with a new NPS 36 ing 13km of the 16" for 5 years wn of Kingsville and new transmission cCormick Station (2018 "McCormack") to 2021) = $(207), 40 years = $(201) to 2022) = $(271), 40 years = $(265) column is the NPV of the Capex and O&M.	5 Yr Capex $ 235 6 Yr Capex $ 334	Cost to maintain 13km of 16" for 5 yrs	01-Nov-17	Replace (lift) remaining 13 km of the exi pipeline between Dover Centre and Dov new NPS 36 pipeline Rebuild Dover Transmission Upgrade Dover Centre Total Capex ~ $ 99 million

distribution network, and ultimately further Panhandle System reinforcement west of Dover Transmission, will be required. Regardless of project scope, the long-term solution to respond to the growing Panhandle System requires increasing the capacity of the Panhandle System beginning at Dawn heading westerly to maintain the required system delivery pressures and serve the growing Design Day demands, as proposed in this Project.

Given that the alternatives presented serve only five years of Design Day demand growth, it is important to consider the additional facilities required in 2022 to continue to meet the ongoing need of the Market. In Table 6-1, Union compares the incremental reinforcement facilities required in 2022 (year 6 of the growth) for the Proposed Pipeline and the alternative that includes incremental Ojibway deliveries. The comparison illustrates that the most economic option over the longer term is the Proposed Pipeline. Please refer to the economic analysis in Exhibit A, Tab 7, Table 7-2.

Table 6-1
Incremental Reinforcement Facilities Comparison in 2022

Base Facilities 2017-2021	**Proposed Pipeline**	**New Pipeline with Incremental Deliveries at Ojibway**
Incremental Facilities in 2022	16 kilometres of NPS 12 pipeline from the NPS 20 pipeline into the Town of Kingsville and build a new station to feed the distribution network.	Lift remaining 13 kilometres of existing NPS 16 pipeline and lay NPS 36 pipeline from Dover Centre to Dover Transmission
	12 kilometres of NPS 6 pipeline looping upstream of McCormick Station in the Municipality of Essex.	
Incremental Capital in 2022	$40 million	$99 million
Total Capital	$305 million	$334 million
Total NPV	**$(239) million**	**$(271) million**

Table 7-1
Stage 1 NPV of Proposal and Alternative ($ Millions) – 20-year Term

	Description	NPV
	Proposed Pipeline (Includes New 40km NPS 36)	$(212)
Alt 1	New Pipeline from Dawn along the Panhandle System (New 40 km NPS 30 Pipeline, Retain existing NPS 16 in service)	$(224)
Alt 2	New Pipelines + Incremental Deliveries at Ojibway	$(205)

The difference in capital cost of the Project relative to Alternative 1 (construct a NPS 30 pipeline and retain the NPS 16 pipeline in service) is $0.5 million. Retaining the existing NPS 16 pipeline in service has a NPV cost of approximately $12 million over a 20-year term. The cost parameters for this outcome are filed at Exhibit A, Tab 6, Schedule 2.

Table 7-1 shows the NPV based on facilities required for a five-year term. A longer term perspective requires additional facilities in year 6. Table 7-2 shows the NPV of the Project and Alternative 2. The NPV of the Project and Alternative 2 are close at five years, and the Project is approximately $32 million favorable on a six-year view. The description of the facilities required in 2022 (year 6) can be found at Exhibit A, Tab 6, Table 6-1.

Table 7-2
Stage 1 NPV of Proposal and Alternative 2 ($ Millions) - 20-year Term

Description	NPV Assets 5 Yrs	NPV Assets 6 Yrs
Proposed Pipeline	$(212)	$(239)
Alternative 2	$(205)	$(271)

Stage 2 – Benefit/Cost Analysis

A Stage 2 analysis may be undertaken when the Stage 1 NPV is less than zero. The Stage 2 analysis considers the estimated energy cost savings that accrue directly to Union's in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirements. The Stage 2 NPV energy cost savings are estimated to be approximately $805 million. The results and assumptions can be found in Exhibit A, Tab 7, Schedule 5.

Stage 3 – Other Public Interest Considerations

There are a number of other public interest factors for consideration as a result of the addition of the Project. Some are quantifiable and others are not readily quantifiable. Quantifiable factors include the GDP, taxes and employment impacts. Other less quantifiable impacts include, but are not limited to, energy choice options and environmental benefits. These factors are detailed below.

Economic Benefits for Ontario

A report titled The Economic Impact of Ontario's Infrastructure Investment Program, (the "Report") was produced by the Conference Board of Canada and published April 2013. This public report quantifies the economic impact of infrastructure spending in Ontario and can be found at Exhibit A,

TAB 8

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Exhibit B.LPMA.6
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UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Reference: Exhibit A, Tab 3, p.9-10.

Union indicates that it is proposing to use an interim allocation of the project costs which is different than the 2013 Board-approved cost allocation methodology used for existing Panhandle System costs. This interim allocation is based on in-franchise Panhandle System Design Day demands, updated to include the incremental design day demands.

a) Does Union propose to change the allocation of these costs as part of its next rebasing application to the interim methodology proposed in this application, or could there be some other proposal brought forward at that time? Please explain fully.

b) If this is an interim allocation methodology during the remainder of the IRM term, does this mean that Union or other parties could seek to change the allocation on a retroactive basis when the deferral account is reviewed for disposition? Please explain fully.

Response:

a) As part of its 2019 Rebasing proceeding, Union will review and propose a cost allocation methodology for all Panhandle System and St. Clair System costs. Union's proposal at that time may be different than the interim cost allocation methodology proposed in this application.

b) The intent of receiving the Board's approval of an interim allocation methodology as part of this proceeding is to allocate the Project costs in rates and dispose of the deferral balance using the approved cost allocation methodology during the remainder of the IRM term. Any approved changes to the cost allocation of the Panhandle System and St. Clair System as part of Union's 2019 Rebasing proceeding will be handled prospectively beginning in 2019.