unionegas
A Spectra Energy Company

December 14, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2015-0179 – Union Gas Limited ("Union") – Community Expansion Corrected Interrogatory Responses

Please find attached the following corrected interrogatory responses that were filed with the Board on December 9, 2015 for the above proceeding:

- Exhibit B.CCC.21
- Exhibit B.Energy Probe.12
- Exhibit B.South Bruce.6

These responses were revised to more accurately reflect the impact of the customer attachment forecast for the Kincardine area. Exhibit B.CCC.21 was also revised to include the TES/ITE deferral credits for all rate classes shown in the Attachments to this response.

These corrected responses were filed in RESS and copies were sent to the Board.

If you have any questions with respect to this submission please contact me at 519-436-5476.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

Encl.

c.c.: C. Keizer, Torys
EB-2015-0179 Intervenor

uniongas
A Spectra Energy Company

December 9, 2015

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2015-0179 – Union Gas Limited ("Union") – Community Expansion Interrogatory Responses

Please find attached Union's responses to the interrogatories received in the above proceeding. These were filed in RESS and copies were sent to the Board.

Please note, the documents requested in Exhibit B.SEC.16 (correspondence exchanged between Union and the communities) are not included in this electronic filing due to the file size. They will be filed under separate cover to the Board and labelled accordingly in RESS. Paper copies and a CD containing the correspondence will be sent by courier to the Board and are also available on Union's website.

The responses reflect an update to Union's evidence that will be filed by December 14, 2015. Specifically, the evidence update includes the impact of Union removing the Walpole Island First Nations Project from its Community Expansion Proposal. The Walpole Island First Nations Project is proceeding with the support of Federal funding, under the Board's E.B.O. 188 guidelines, at a P.I. of 0.8. As a result, the Project no longer requires Union's Community Expansion Proposals to make it economically feasible. The evidence update also reflects the impact of revisions made as a result of further costing and economic analysis performed on a potential Community Expansion project to the Kincardine area.

In addition, as stated in its response to Exhibit B.LPMA.24 and Exhibit B.Energy Probe.5, a live excel spreadsheet as requested has been provided to the requesting parties via email, copying the Board. Other parties who wish to receive a copy of the documents can contact Union directly.

If you have any questions with respect to this submission please contact me at 519-436-5476.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

Encl.

c.c.: C. Keizer, Torys
EB-2015-0179 Intervenor

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 4, lines 1-8

Union Gas Limited (Union) has indicated that under its proposal, it could complete 30 projects that would provide natural gas service to approximately 20,000 homes and businesses in 34 communities, including 7 First Nations. The bill impact of the 30 projects for the average residential customer in Union South is an increase of $3 to $4 per year while the bill impact for an average residential customer in Union North is an increase of less than $1 per year.

a) What would be the additional funding or contribution required for the 30 projects if Union were to not include any contribution from existing customers for the Community Expansion Project proposal?

b) In reference to part a), what would be the average contribution required from each new community expansion customer in the absence of contribution from existing customers?

Response:

a) The Aid-to-Construction required for the 30 projects to achieve a P.I. of 1.0 is approximately $68.0 million.

b) The $68.0 million aid is the amount needed to be collected in advance. However, on a practical basis, a prospective customer would only pay an aid at the time they connect. Therefore, the cost of funding the infrastructure would occur in the initial year and the revenue from those customers and the collection of the aid would occur over many years. The aid required to address the timing impacts would be more than $68.0 million.

   As an illustrative example, $68.0 million divided by 9,107 customers results in an aid of $7,467 per connecting customer. The 9,107 customers is the 10 year estimate of attachments out of approximately 18,400 potential customers. An aid payment such as this would diminish customer receptivity to connection creating a circular requirement to add more aid to the remaining prospective customers.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 6, lines 5-15

In its evidence Union has noted that its proposal is guided by a set of principles designed to recognize those who are impacted by or benefit from expansion of Union's natural gas system. Union further notes that moderate cross subsidization from existing customers is acceptable, provided long-term rate impacts are reasonable.

a) Does Union's proposal requiring existing ratepayers to pay a portion of the costs of expanding into the new communities create a competitive disadvantage for companies that are interested in providing natural gas service to non-serviced communities but do not have access to an existing pool of ratepayers that can contribute to the cost of the project?

b) Would Union be receptive if the Ontario Energy Board (OEB) were to approve a similar approach as that proposed by Union whereby a company that is interested in providing natural gas service to a non-served community, is also permitted like Union to recover a portion of the costs of the project from Union ratepayers?

Response:

a) In addition to being a natural monopoly, and for the reasons set out below, the distribution of natural gas is a regulated activity and not procured in a competitive market. As such, there is no competitive advantage or disadvantage to having an existing customer base. There is no Board policy of forbearance as in the case of storage or LNG production.

b) No. Union would not support such a mechanism, as it is inappropriate for start-up utilities to be financed by existing utility ratepayers. Furthermore, as there is no explicit legislative authority for the Board to create such a mechanism, it is questionable that the Board could enact such a mechanism even if it was so inclined.

   If the rates Union is required to charge its customers were to include amounts that would be used as a subsidy, that portion of Union's rates would not be based upon any underlying costs incurred by Union to serve its customers. Rather, that portion of Union's rates would be based on the costs incurred by another distributor to serve its customers. To the extent that Union's rates are based upon such costs that are unrelated to the regulated service that it provides, such rates would not be in accordance with the just and reasonable standard.

Imposing a charge on Union's customers for purposes of subsidizing another distributor's cost of service would be contrary to the established ratemaking principle of "benefits follow cost". Union's customers would be incurring costs without receiving any corresponding benefits.

Subsidization would also be contrary to the standalone principle of ratemaking, which holds that only those costs and risks that pertain to the activities of a regulated utility in respect of the provision of service to ratepayers should be reflected in the revenue requirement of that utility. To charge a subsidy would be to include in Union's revenue requirement costs that are unrelated to the activities of the regulated utility. Alternatively, it would mean that amounts would be included in rates that are in addition to Union's revenue requirement.

It would also be contrary to the just and reasonable standard if the other distributor were permitted, through the rates it charges to its own customers, to earn a return on the portion of its rate base that, with subsidization, would effectively be paid for by Union's ratepayers.
In effect, the subsidy would be subsidizing the return of the other distributor and, if the subsidy were to occur, the other distributor should have a corresponding reduction in rate base or return.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, pp.14-15

Union has provided a list of components under its community expansion proposal. The proposal lists different elements including a temporary expansion surcharge, incremental tax equivalent, exemption from some E.B.O. 188 guidelines and other such measures.

Has Union considered other measures that would make community expansion projects viable such as:

i. Flexibility on the project Return on Equity for the first five years of each Community Expansion project in order to contribute to the overall viability of the projects and reduce the cost burden on the other stakeholders including existing customers.

ii. To include the capital cost of the projects in rate base that reflect a PI of 1.0 and recover the remaining of the capital costs through the expansion surcharge, incremental tax equivalent and contributions from existing ratepayers.

Please comment on each of the measures noted above and provide reasons for accepting or rejecting the approach.

Response:

Union has structured its proposal to meet the government's goal to complete the maximum number of projects, and Union has applied its experience, judgment and regulatory precedent to minimize ratepayer impact.

The regulatory precedent referenced is the framework issued by the Board in 2014 which stated that the annual cost impact of Union's DSM programs should be limited to a maximum of $2.00 per month for a typical residential ratepayer[1]. Union's proposal to limit the maximum ratepayer impact of a Community Expansion Program is entirely consistent with this figure.

i) Union would not accept a lower return on equity, as it should earn a fair return on its prudently-incurred capital. Furthermore, Union would not be pursuing this proposal in the absence of Ontario government direction to further expand natural gas service, and therefore

[1] EB 2014-0134, Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 17, http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf

should not be otherwise penalized for responding to this direction.

ii) This question limits the rate base to the cost to achieve a P.I. of 1.0. Union's proposal is for the full capital cost to be included in rate base with recovery of the necessary revenue requirement from a combination of TES, ITE, the delivery revenues from the project customer additions, and, finally, contributions from existing ratepayers to support the resulting revenue deficiency.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 14, lines 9-12

Union has indicated that under its proposal, it could complete 30 projects that would provide natural gas service to approximately 20,000 homes and businesses in 34 communities, including 7 First Nations. Additional funding or financial contributions would be required to service the remaining communities identified in the Opportunity Assessment.

a) Please identify the 30 projects that Union is referring to in the application.

b) Is Union open to partnering with other companies or utilities to provide service to communities identified in the Opportunity Assessment?

c) Has Union been approached by any companies or utilities to partner in the Community Expansion Project? If yes, please provide a detailed response.

d) Would Union consider modifying its proposal if it were to partner with other companies or utilities to provide service to communities identified in the application?

Response:

a) The 30 projects are listed in Exhibit A, Tab 1, Appendix D, p. 1, rows 1 to 33, but excluding rows 16, 18, and 30. The intent of including all 30 Projects in evidence was to allow the Board to understand the greatest magnitude of rate impacts if all potential projects were to proceed. Before making any decision to propose installation of any Projects beyond the initial five proposed in Exhibit A, Tab 2, Union would undertake a detailed analysis of the feasibility of each of the Projects[1]. If the Projects are confirmed to be feasible under Union's proposal, Union would then seek Board approval for recovery of the resulting revenue deficiency, or in some cases, Leave-to-Construct. Necessary evidence to support these future applications will be filed with the Board.

b) Union would be open to partnering with other entities, provided that such a partnership could bring incremental value beyond that which Union could deliver on its own.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

c) Union has not been approached with any formal proposals, however, on an informal basis there have been discussions as noted below:

   One municipal group asked about interest in the form of a joint venture or partnership. Union responded stating it is not interested in the potential opportunity. Union's rationale was that the first opportunity would in Union's opinion result in a system design that would present significantly greater gas supply reliability risk. In another alternate scenario Union declined because it did not appear that there would be any incremental value in a partnership.

   One party approached Union about potential interest in another opportunity using technology that Union was concerned represented increased supply reliability risks, which Union was not comfortable taking at the time.

d) Yes, Union would have to consider the ramifications of any partnership opportunity to ensure the long-term benefits to existing ratepayers are not significantly affected.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 17, lines 8-11

Union has noted that the Temporary Expansion Surcharge (TES) will be applied to potential general service customers attaching to systems installed as part of Community Expansion Projects, where a contribution from customers in excess of $500 each is required to make a project economically feasible.

What is Union's proposal in cases where a contribution of $500 or less is required from each potential general service customer?

Response:

If $500 or less is required from each customer in the Project area, the amount would be treated as an up-front Aid-to-Construction requirement. Union's application to the Board for rate recovery for a Project of this nature would include the specific timeframe during which Union would require every customer who connects to the system to make this payment prior to their service being activated. The capital cost included in rate base would exclude the collective value of the Aid-to-Construction payments.

Union does not expect this scenario to be likely, as no Community Expansion Projects identified to this point would meet these criteria.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 23, lines 7-8

One of the proposals of revenue recovery includes an additional contribution from municipalities of the new communities known as the Incremental Tax Equivalent (ITE). Union notes that only municipalities that wish to pursue Community Expansion Projects at reduced economic threshold levels below a PI of 0.8 would be required to agree to the ITE.

If a municipality does not wish to pursue a project that is below the PI of 0.8, would Union abandon the project or pursue other means to bridge the financial gap? Please provide a detailed response including other proposals that Union may consider to make such projects viable.

Response:

If a municipality does not wish to pursue a Project below a P.I. of 0.8, Union would work with the municipality to pursue other options to make the Project viable. This could include supporting the municipality in seeking Aid-to-Construction funding from other sources, including the government.

One of these options is presented in Exhibit A, Tab 2, Section A, of Union's evidence, for the proposed Kettle Point/Lambton Shores Project. In the case of Lambton Shores, the municipality was not able to agree to an ITE, and for this reason the Lambton Shores component of the combined Kettle and Stony Point First Nations/Lambton Shores Project is being proposed at the previously existing E.B.O. 188 minimum P.I. threshold of 0.8. Extending the TES term for contributions from the potential customers in that area will allow that portion of the Project to meet the 0.8 threshold. For the remainder of the Project, the Kettle and Stony Point First Nations have agreed to the ITE, so that part of the Project is being proposed at a lowered P.I. of 0.4.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 24, lines 7-10

Union has proposed that the economic threshold for Community Expansion Projects be lowered to a PI of 0.4 from the current minimum of 0.8. Union has noted that reducing the PI to 0.4 allows it to achieve a balance of furthering the provincial goal of providing customers in non-serviced communities the ability to gain access to natural gas, while being mindful of potential rate impacts for existing ratepayers.

a) Please provide a revised proposal for the Community Expansion Project if the PI is lowered from the current minimum of 0.8 to 0.6 and an upfront contribution of $500 is required from each community expansion customer. Please assume that the TES and ITE requirements remain the same as the original proposal. Also, provide bill impacts for existing customers under the revised proposal.

b) Would Union still complete 30 projects if the project criteria were revised as set out in (a)?

Response:

a-b) In the absence of Aid-to-Construction beyond the $500 per customer, applying the criteria above would reduce Union's potential Project list to 12 Projects, listed in Exhibit A, Tab 1, Appendix D (Updated), p. 1, lines 1-14, but excluding lines 4[1] and 11. The gross capital expenditure for these Projects would be $32.6 million, prior to Aid-to-Construction of approximately $1.5 million (2,928 customers * $500). Annual bill impacts for an average residential customer consuming 2,200 m^3 per year would increase by approximately $0.06 and $0.72 for Rate M1 and Rate 01 customers respectively including the TES and ITE deferral credits. Please see Attachment 1, p. 1 for the calculation of annual bill impacts for Rate M1 and Rate 01 customers consuming 2,200 m^3 annually and Attachment 1, p. 2 for the calculation of annual bill impacts including the TES and ITE deferral credits.

The last column on the right of Appendix D shows the aid required to meet a P.I. of 0.6. Astorville (line 15) requires $0.21 million in aid to reach a P.I. of 0.6, after applying TES and ITE for 10 years. With a forecast of 210 customers the Aid-to-Construction collection would be $0.11 million (210 * $500) resulting in a P.I. less than the 0.6 minimum P.I. defined in the question. The NPV of the aid would actually be less than $0.11 million because the collection would occur over time as customers initiate gas service. All lines below Asterville in Exhibit

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

A, Tab 1, Appendix D would require Aid-to-Construction beyond $500 per customer.

This simplified calculation inherently means that a customer connecting in year 10 of the forecast horizon is also paying the $500 aid at that time.

The proposal in the question adds an additional $500 cost to customers to connect and would likely affect attachment rates and timing. Reduced attachment forecasts that might result have not been included in the above outcome.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Potential Community Expansion Projects that Achieve a P.I. of 0.6 Including a $500 Upfront Contribution
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.63	0.31	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.31	(0.01)	
5	Total Delivery Charge	349.64	349.94	0.31	0.1%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.34	0.31	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.31	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.31	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.09	1.82	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	449.09	1.82	0.4%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	991.36	1.81	0.2%
22	Impacts for Customer Notices - Sales (line 19)			1.81	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.81	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Potential Community Expansion Projects that Achieve a P.I. of 0.6 Including a $500 Upfront Contribution
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.63	0.31	
3	Delivery Price Adjustment	-	(0.25)	(0.25)	
4	Storage Services	16.32	16.31	(0.01)	
5	Total Delivery Charge	349.64	349.69	0.06	0.0%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.09	0.06	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.06	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.06	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.09	1.82	
14	Delivery Price Adjustment	-	(1.08)	(1.08)	
15	Total Delivery Charge	447.28	448.01	0.74	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	990.28	0.72	0.1%
22	Impacts for Customer Notices - Sales (line 19)			0.72	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			0.72	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 25, lines 6-15

Union has recommended that the economic threshold for Community Expansion Projects be reduced from the OEB allowed minimum PI of 0.8 to a PI of 0.4. With a PI of 0.4, Union estimates that it can reach 20,000 potential customers in 34 communities. However, Union has indicated that lowering the PI from 0.5 to 0.4 provides Union the opportunity to pursue the Community Expansion Project in Kincardine.

a) If Union were to exclude the communities of Kincardine, Tiverton, Paisley and Chesley, should Union's proposal include an economic threshold of a PI of 0.4 or 0.5?

b) What would be the impact on Union's Community Expansion Project if the PI threshold is increased to 0.5? Please provide a detailed response including which of the 30 communities would be excluded.

Response:

a) If Union were to exclude the communities of Kincardine, Tiverton, Paisley and Chesley, it would still propose a minimum P.I. of 0.4, because eight additional Projects to provide access to 2,181 customers may be feasible in comparison to the number of Projects feasible at a P.I. of 0.5. These Projects are listed in Exhibit A, Tab 1, Appendix D, p. 1, rows 24 to 33, but excluding rows 29 and 30.

   Union does not propose excluding the communities of Kincardine, Tiverton, Paisley and Chesley. Although the communities have asked another potential LDC to develop a proposal, a firm proposal as represented by an application to the Board has not been made. Union may still have a viable or more cost effective proposal for this Project, which may also be bundled with the Ripley/Lucknow Project (Exhibit A, Tab 1, Appendix D, p. 2, row 54). Please see the response at Exhibit B.South Bruce.6 c) for further details.

b) At a minimum P.I. of 0.5, assuming Union's other proposals are unchanged, Union could complete 21 Projects. These Projects are listed in Exhibit A, Tab 1, Appendix D, p. 1, rows 1 to 23 but excluding lines 4[1], 16 and 18.

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 28, lines 12-19

Union has noted that in the absence of applying the E.B.O. 188 portfolio approach to Community Expansion Projects, Union proposes limiting the capital spending for Community Expansion Projects to a ceiling that ensures that the resulting maximum expected annual increase is $2 per month for existing residential customers. Union has also proposed that the impact in any given year of the multi-year Community Expansion program will not exceed $10 for a typical residential customer consuming 2,200 m^3 per year.

Please reconcile the two maximum annual rate impacts of $24 per year and $10 per year? Please explain the difference between the two rate impacts.

Response:

Union's proposal is that any increase in rates resulting from Community Expansion projects in one specific year be limited to a maximum of $10 for a typical residential customer. However, Union was also concerned about the cumulative impact of a multi-year expansion program on existing customers. For this reason, Union proposed that the cumulative impact on rates for a multi-year period be limited to a ceiling of $24 per year (average of $2 per month) relative to rates that would have existed absent a Community Expansion Program.

Union does not expect to file for all future projects in a single year, so the rate impacts of the potential $150 million in capital spending will occur over a period of time. For example, if the projects were to be evenly spaced over two years, Union would recover $75 million of additional rate base in rates in one year and another $75 million in the following year. Using Union South as an example, the cumulative rate impact of $5.64[1] per year resulting from the related capital expenditures for a typical residential customer would not all occur in a single year. If 50% of the investment occurs over each of two years, presumably half the rate impact would occur in one year, the remaining half would occur the following year, with the cumulative resulting rate increase over the two year period being $5.64 per customer.

The maximum annual ($10) and cumulative ($24) proposed are higher than the rate impacts anticipated for the 30 possible projects identified in Union's proposal in order to provide flexibility for changes to the potential project list if the Provincial funding becomes available, or if additional projects become more feasible as a result of new information becoming available. The rate impacts will be offset by annual deferral account credits related to the TES and ITE collected for all Community Expansion Projects and disposed of to all ratepayers.

[1] Exhibit A, Tab 1, Appendix L, lines 9 and 10.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 1, p. 33, lines 10-19

Union has noted that the purpose of the proposed Community Expansion Contribution deferral account is to allocate the TES and ITE revenues to ratepayers to reduce the cross subsidization of the capital costs.

a) Would the revenue in the deferral account be credited to all general service customers?

b) Would the revenue be credited to all customers of Union including new community expansion customers or to customers excluding new community expansion customers?

Response:

a) Union's proposal is to allocate the balance in the Community Expansion Contribution Deferral Account to rate classes per Exhibit A, Tab 1, Updated, p.33 and Exhibit A, Tab 1, Appendix K, Updated. Where Union has proposed an allocation of the deferral balance to a general service rate class, the balance will be credited to all general service customers including new Community Expansion customers.

b) Please see the response at a) above.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section A, p. 4, para. 19

Union conducted a survey in the Ipperwash Beach area. At the time of the application, Union has noted that of the 380 potential customers in the Ipperwash Beach area, only 22 have completed the telephone survey, representing a 6% response rate. Union Gas has further indicated that it is planning a door-to-door survey to increase the participation rate.

a) Please provide a copy of the survey used in the research.

b) In Union's opinion, does a low response rate imply that residents are not seriously interested in natural gas service and conversions could be challenging in such areas?

c) Union has noted that it is planning a door-to-door survey. Has the door-to-door survey commenced and when is it likely to be completed?

d) Will Union be filing the results of the door-to-door survey in this application?

Response:

a) Please see Attachment 1 for the survey results for Ipperwash Beach (Lambton Shores). Also included in Attachment 2 and 3 are the survey results for Milverton and Prince Township.

b-d) The low response rate for Ipperwash Beach (Lambton Shores) was due to the timing of the survey. As a result, Union proceeded to complete a door-to-door portion as well as a telephone survey to increase participation rates. Union has completed the Ipperwash Beach (Lambton Shores) area survey. The response rate was 37%. The results indicate that when respondents consider both the conversion cost and volumetric surcharge, in aggregate, 56% of respondents would be "extremely" or "very likely" to convert any of their space heating and/or water heating to natural gas (both space heater and water heater, space heating only, and water heating only) and 30% would be "extremely" likely to convert. For additional information, including the results of the door-to-door survey please see Attachment 1.

180 Bloor Street West
Suite 1400
Toronto, Ontario
M5S 2V6
T (905) 960-3255
F (416) 960-6061
www.forumresearch.com

FORUM
RESEARCH INC.

Gas Pipeline Expansion Study
Lambton Shores

Research Report Prepared for: Union Gas Limited

July 22, 2015

FORUM
RESEARCH INC.

Table of Contents

Background	3
Research Objectives	3
Methodology	3
Highlights	4
Findings	5
Space Heating	5
Water Heating	7
Likelihood to Convert with Surcharge	8
Conversion Time	9
Other Appliances	9
Demographics and Housing Characteristics	10
Appendix: Questionnaire and Record of Contact	12

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Background

Union Gas (Union) operates in northern, southwestern, and eastern Ontario delivering natural gas services to over 1.3 million residential, commercial, and industrial customers in more than 400 communities. However, the town of Lambton Shores, located in southwestern Ontario is not currently serviced by Union. Given the operating cost advantages of natural gas, Union believes that there is significant interest in converting to natural gas, particularly for space and water heating. Union is reviewing the feasibility of extending the gas pipeline that will service the citizens of Lambton Shores Ontario.

In addition to the cost of converting space and water heating equipment to natural gas, households typically are required to make a contribution toward the pipeline capital costs of extending service to the community. Union has developed a volumetric surcharge for those that elect to convert, as a means to overcome the upfront capital cost barrier that households would face upon conversion. Market research in Lambton Shores Ontario is needed to measure the likelihood of converting to natural gas given potential savings, conversion costs and the volumetric surcharge alternative for recovering upfront pipeline extension costs.

Research Objectives

The objective of this research is to ascertain interest in obtaining natural gas service amongst the residential household population of Lambton Shores Ontario. Specifically, this research is designed to:

- Measure the likelihood of converting heating equipment based on a range of typical equipment conversion costs.
- Gauge interest in switching to natural gas water heating based on a range of typical equipment conversion costs.
- Measure the impact on likelihood of conversion based on a volumetric surcharge (cents per m^3) that would apply to natural gas consumption following conversion.

Methodology

To achieve the research objectives, Union retained the services of Forum Research, a third party research supplier, to conduct the quantitative study. A total of 104 telephone (n=26) and door-to-door interviews (n=78) were completed from a list of 278 home and business owners in Lambton Shores between April 16th and May 31st, yielding a +/- 7.6% margin of error at the 95% confidence level. The level of completes represents a 37% response rate.

FORUM
RESEARCH INC.

Highlights

- Overall, 66% of respondents are "extremely" or "very likely" to convert their **space heating** systems to natural gas based on the cost of converting their equipment.
    - Propane forced air is the most prevalent space heating system used in Lambton Shores (53%). Electric heating (forced air or baseboard) heats 22% of Lambton Shores households. The remaining 1-in-4 households (26%) use a variety of other heating sources (oil forced air, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else).

- Over half of respondents (57%) are likely to convert their **water heaters** to natural gas.
    - Virtually all Lambton Shores respondents own their water heaters (88%) and the majority currently uses electricity as the main fuel source (77%).

- With an additional contribution to pipeline construction through a volumetric surcharge, 56% of respondents overall are "extremely" or "very likely" to convert their space heating systems and/or water heaters to natural gas.

- 58% of Lambton Shores homes are used year-round.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Findings

Space Heating

This study indicates that the most prevalent space heating system used in Lambton Shores is propane forced air (53%). Electric heating (forced air or baseboard) heats 22% of Lambton Shores households. The remaining 1-in-4 households (26%) use a variety of other heating sources (oil forced air, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else).

Electric forced air/electric baseboard systems tend to be the oldest systems (36% are 25 years and older). Therefore, users are far more likely to replace them in the next two years (45% are extremely likely/very likely/likely to replace them).

Overall, 66% of respondents would be "extremely" or "very likely" to convert their space heating systems to natural gas (when given the equipment conversion cost only). Propane forced air users are more likely to convert to natural gas (78%) than respondents with other systems.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Table 1: Space Heating
Base: All respondents

	Total (n=104)	Propane Forced Air (n=55)	Electric Forced Air/Electric Baseboard (n=22)	Other* (n=27)
Penetration		53%	22%	26%
Likely to replace in the next 2 years (Top 3-Extremely/very/likely to replace)	31%	22%	45%	29%
Age of heating system				
5 years or less	27%	29%	9%	33%
6 to 10 years	30%	35%	23%	29%
11 to 15 years	16%	22%	14%	5%
16 to 25 years	14%	9%	14%	24%
25+ years	11%	4%	36%	5%
Top 2-Extremely/very likely to convert to NG (Equipment conversion cost only)	**66%**	**78%**	**50%**	**41%**
Top 3-Extremely/very/likely to convert to NG (Equipment conversion cost only)	**81%**	**93%**	**68%**	**64%**
Extremely likely	44%	53%	32%	27%
Very likely	21%	25%	18%	14%
Likely	16%	15%	18%	23%
Not very likely	7%	5%	9%	9%
Not at all likely	7%	-	9%	23%

* No heating system, oil forced air, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump, or something else

Note: The sample size of respondents using oil forced air is too small for separate analysis (n=5). Oil forced air users are included in “Other”.

FORUM RESEARCH INC.

Water Heating

Virtually all Lambton Shores respondents own their water heaters (88%), and the majority use electricity as the main fuel source (77%).

About two-thirds of respondents (65%) have had their water heaters for 10 years or less. One-in-three respondents (32%) have had them for five years or less.

Overall, 57% of respondents would be "extremely" or "very likely" to convert their water heaters to natural gas.

Table 2: Water Heating
Base: All respondents

	Total (n=104)*	Propane (n=16)	Electricity (n=80)
Penetration		15%	77%
Own water heater	88%	88%	93%
Age of water heater			
5 years or less	32%	31%	31%
6 to 10 years	33%	31%	33%
11 to 15 years	18%	31%	16%
16+ years	13%	6%	15%

	Rent (n=11)	Own (n=92)
Extremely/very likely to convert water heater to NG **	**57%**	
Extremely likely	–	33%
Very likely	9%	30%
Likely	45%	17%
Not very likely	9%	15%
Not at all likely	18% (DK=18%)	4%

*** Includes oil, geothermal/heat pump or something else. The sample size of respondents using these other sources is too small for separate analysis (n=8) and is excluded from the above Table.**
**** Total who own or rent.**

FORUM
RESEARCH INC.

Likelihood to Convert with Surcharge

Respondents who indicated they are likely to convert either space or water heating systems to natural gas were asked their likelihood to convert if an additional financial contribution toward pipeline construction were required, in addition to the equipment conversion cost. The additional pipeline surcharge would be 23 cents per cubic metre for a 5 to 10 year period. For the typical residential home, this would add to about $350 to $450 a year (about $100 per year if converting the water heater only).

When respondents consider both the **conversion cost and volumetric surcharge**, in aggregate, 56% of respondents would be "extremely" or "very likely" to convert any of their space heating and/or water heating to natural gas (both space heater and water heater, space heating only, and water heating only) and 30% would be "extremely" likely to convert.

Table 3: Likely to Convert – With Surcharge
Base: Those likely to convert to Natural Gas (Equipment conversion cost only)

		Likely to Convert Both Space Heater and Water Heater (Extremely/Very/Likely) (QS10 to S12)				Likely to Convert Space Heater Only (Extremely/Very/Likely) (QS13 to S15)	Likely to Convert Water Heater only (Extremely/Very/Likely) (QS16)
	TOTAL POPULA-TION (n=104)	Oil Forced Air (n=4)**	Propane Forced Air (n=44)	Electric Forced Air/ Electric Baseboard (n=14)	Other* (n=12)	(see Note 1) (n = 10)	Water Heater (Own or Rent) (n=7)**
Likelihood to convert with surcharge							
Top 3 – Extremely/ Very/Likely	**70%**	**--**	**84%**	**71%**	**83%**	**70%**	**--**
Top 2 – Extremely/ Very likely	**56%**	**--**	**68%**	**71%**	**50%**	**50%**	**--**
Extremely likely	**30%**	**--**	**34%**	**50%**	**25%**	**30%**	**--**
Very likely	**26%**	**--**	**34%**	**21%**	**25%**	**20%**	**--**
Likely	**14%**	**--**	**16%**	**--**	**33%**	**20%**	**--**
Not very likely	**11%**	**--**	**9%**	**14%**	**8%**	**20%**	**--**
Not at all likely	**3%**	**--**	**7%**	**--**	**-**	**--**	**--**

* No Heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else
** Extremely small base, details not reported when n < 10.
Note 1: Consists of Oil Forced Air/Propane Forced Air/Electric Forced Air/Electric Baseboard/Other.

Conversion Time

Respondents who indicated they are likely (extremely, very, or likely) to convert space heating systems and/or water heaters to natural gas if a surcharge was required were asked when they are likely to do so if natural gas is available after December 2015.*

For those indicating extremely/very likely to convert, 53% would do so within the first 12 months, 20% are likely to convert within 1-2 years, and 20% are likely to convert within 2-3 years. **

Other Appliances

Respondents who are likely to convert their space heating systems and/or water heaters to natural gas were asked if they would be interested in converting other appliances to natural gas as well.* The small number of responses indicate interest in converting other appliances: between 33% and 60% of respondents are "extremely" or "very" interested in converting their fireplaces, clothes dryers, ovens/stoves and/or BBQs to natural gas.**

Table 4: Interest in Converting Other Appliances to Natural Gas
Base: Those likely to convert to Natural Gas (with surcharge)

	BBQ (n=15)	Fireplace (n=15)	Oven/ Range/Stove (n=15)	Clothes Dryer (n=15)
Extremely/very interested in converting other appliances	60%	33%	53%	33%
Extremely interested	27%	20%	20%	–
Very interested	33%	13%	33%	33%
Interested	27%	20%	7%	33%
Not very interested	7%	7%	13%	13%
Not at all interested	–	27%	27%	20%
Don't know/not stated	7%	13%	–	–

***As noted in the Methodology section of this report, interviews in Lambton Shores were completed using both computer assisted telephone and computer assisted face to face interviewing technologies. The data reported upon in these sections is only from the telephone interviews that were completed. The VOXCO software used to program the questionnaire for face to face interviewing could not properly process the number of variables required to determine who answered these questions. Unfortunately, this limitation was not apparent until all face to face interviews had been completed, consequently only partial data from telephone interviews is available for analysis.**

****These percentages should be interpreted with extreme caution. Not only are they for a very small sample (n=15), but they are solely from the telephone interviews. Consequently, they may not be fully representative of the broader population.**

Demographics and Housing Characteristics

Bungalows make up the majority of homes in Lambton Shores, accounting for 63% of all respondent households. The average house size is 1775 square feet and the age of the home varies: about 1-in-3 homes (34%) are under 35 years of age; 38% are between 35 and 64 years old; and 18% are 65 years of age or more. Over half (58%) of homes are used by year-round, full-time residents, and 39% are used mostly as summer homes.

59% of Lambton Shores respondents are 55 years or older, while only 1% is under 35 years of age. Therefore, the majority of residences house 1 or 2 adults (84%) and no children (75%).

Just over half of households (53%) have incomes of $40,000 or more: 29% earn $40,000 to $80,000 and 24% earn more than $80,000. Seventeen percent households (17%) report income between $20,000 and $60,000.

Directional findings suggest that other demographic attributes of interest are:

- Bungalows and smaller houses up to 1,500 square feet are more likely than larger houses to be summer homes (49% of bungalows are occupied mostly in the summer versus 23% of other types of houses).
    - This may be one reason why bungalow owners are less likely to replace their heating systems in the next two years (22% of bungalow systems are extremely likely/very likely/likely to be replaced versus 46% of other types of houses).
- Newer houses are more likely to use propane water heaters
    - 5% of houses built in 1950 or earlier and 23% houses built in 1981 or later use propane for water heating.

FORUM
RESEARCH INC.

Table 5: Demographics – Residence
Base: All "Residence" Respondents

	Total (n=104)
Building Type	
Bungalow/One storey ranch	63%
Two storey	21%
Split level	13%
Three storey	2%
Raised ranch	2%
Approximate size of home (in sq. feet)	
Less than 1,000	10%
1,000 to 1,500	39%
1,501 to 2,000	23%
Over 2,000	21%
Don't know	7%
Average size	**1775 sq. ft.**
Occupancy of Dwelling	
All-year round	58%
Mostly in the summer months	39%
Occasionally year round	3%
Ave months (among partial year occupants n=44)	**10 months**
Age of home	
0 to 34 years	34%
35 to 64 years	38%
65+ years	18%
Don't know/not stated	11%
Age of respondent	
18 to 34 years	1%
35 to 44 years	7%
45 to 54 years	29%
55 to 64 years	32%
65+ years	27%
Number of adults 18 years or older living in house	
1-2	84%
3+	13%
Number of children 17 years or younger living in house	
0	75%
1-2	16%
3+	5%
Total Household Income	
Less than $40,000	8%
40,000 to $80,000	29%
More than $80,000	24%
Refused	39%

Appendix: Questionnaire and Record of Contact

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

3 Community System Expansion Questionnaire
April 13th, 2015

Good morning/evening. My name is ______ and I am calling from Forum Research on behalf of Union Gas. We are conducting a survey to assist in determining whether natural gas will be extended to your area. You may have previously participated in a survey on this issue, but the results of this particular survey are very important, as they will help us to evaluate whether extending the gas system can be proposed to the Ontario Energy Board in the next year. I want to assure you that we are not selling anything and the information you provide to us will be aggregated with others for reporting purposes.

SCR1. Are you 18 years or older and the person responsible for making energy decisions for the property at (SPECIFY ADDRESS)?

Yes, speaking
No, I'll get them
No, not available
[IF YES, SPEAKING, CONTINUE]
[IF NO, I'LL GET THEM, REINTRODUCE]
[IF NO, NOT AVAILABLE, SCHEDULE CALLBACK THEN THANK AND TERMINATE]
[IF NOT AT THIS LOCATION, RECORD DECISION MAKER'S CONTACT INFORMATION (FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE) THANK AND TERMINATE. ADD REFERRAL TO CONTACT LIST]

SCR3. Do you own or rent this property at (SPECIFY ADDRESS)?
Own
Rent

[IF OWN, CONTINUE]
[IF RENT, GET CONTACT INFO – FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE - OF OWNER AND TERMINATE. IF REF, THANK AND TERMINATE]

SCR4. **(DO NOT ASK) RECORD GENDER**
Male
Female

SCR5 (2015). Is this a residence or a business?
Residence
Business
Both Residence and a Business

IF (COMMUNITY = Lambton Shores OR COMMUNITY = Prince Township) AND SCR5 (2015) = Business THEN THANK AND TERMINATE.
NOTE:
IF SCR5 (2015) = "BOTH RESIDENCE AND A BUSINESS" THEN CONSIDER IT A "RESIDENCE" FOR INTERVIEW PURPOSE.

SECTION H: Home Heating

H1. What type of system provides the primary source of heat for this premise? Is it…?

[READ, RANDOMIZE]
Oil Forced Air
Electric Forced Air
Propane Forced Air
Electric Baseboard
Oil Boiler (Hot Water Radiators)
Propane Boiler (Hot Water Radiators)
No heating system
Or Something Else (SPECIFY)

IF H1 = NO HEATING SYSTEM, SKIP TO H8, ELSE CONTINUE
Other **[SPECIFY]**

H2. How old is your heating system? **(READ)**

5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

H3. How likely are you to replace your heating system in the next 2 years? Are you…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H5 IF H1 = OIL FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H5a]
H5. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $2,000 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H5a IF H1 = ELECTRIC FORCE AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H6]

H5a. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H6 IF H1 = PROPANE FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H7]
H6. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to natural gas is likely in the range of $500 to $1,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H7 IF H1 = ELECTRIC BASEBOARD, ELSE SKIP TO INSTRUCTIONS BEFORE H8]

H7. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a high efficiency natural gas furnace is likely to be about $10,000 depending on the specific style and size of your premise. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK H8 IF H1 = NO HEATING SYSTEM, OIL BOILER, PROPANE BOILER OR SOMETHING ELSE.]

H8. Installing a high efficiency natural gas furnace is likely to cost about $4,000-$5,000 if you already have forced air ductwork and $10,000 if it doesn't. However, with natural gas, you may save up to $2,000 off the annual cost of heating with oil, propane or electricity. If natural gas service was extended to your area, how likely are you to install a natural gas heating system? Would you say you are...?
(READ)

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

FORUM
RESEARCH INC.

[ASK H9A IF H5/H5a/6/7 = NOT VERY LIKELY *OR* NOT AT ALL LIKELY]
H9a. You indicated that you are unlikely to convert your heating system to natural gas. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home (or facility) / moving
Too expensive
Other: **[SPECIFY]**

[ASK H9B IF H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY]
H9b. You indicated that you are unlikely to install a natural gas space heating system. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
This is a cottage occupied only in the summer
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home/ moving
Too expensive
Other: **[SPECIFY]**

SECTION W: Water Heating

ASK ALL
Now, I would like to ask you a few questions about your water heater.

W1. What is the MAIN fuel source for heating your water?

Propane
Oil
Electricity
Other: **[SPECIFY]**

FORUM
RESEARCH INC.

W2. How old is your water heater?

(READ)
5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

W3. Is your water heater owned or rented?

Owned
Rented

[ASK W5 IF W3=OWNED]
W5. The purchase and installation of a typical natural gas water heater costs about $1600 depending on the complexity of the installation. However, with natural gas, you may save up to $200 off of your water heating costs every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK W5a IF W3=RENTED]
W5a. Natural Gas water heaters can also be rented. Typical monthly rental rates range from $13 per month to $24 per month. Depending on the specific style of your premises, the property owner may incur additional expenses for the conversion. However, with natural gas, you may save up to $200 off your water heating bill every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are... ? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

FORUM
RESEARCH INC.

SECTION S: CONVERSION LIKELIHOOD WITH VOLUMETRIC SURCHARGE

SPACE AND WATER HEATING

INTERVIEWER NOTE FOR QUESTIONS S10 – S16:
IF RESPONDENT ASKS ABOUT THE OPTION OF A GOVERNMENT LOAN OR GRANT FOR CONSTRUCTING THE GAS PIPELINE, INTERVIEWER SHOULD MENTION THAT THIS IS NOT PART OF THE UNION GAS PROPOSAL AT THIS TIME.

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S10. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1750 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S11. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating costs. **Considering this, how**

FORUM RESEARCH INC.

likely are you to convert your space heating and water heating to natural gas? Would you say...?
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5A = EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S12. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SPACE HEATING ONLY

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S13. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1650 a year on your

FORUM
RESEARCH INC.

heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF OR H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S14. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5a= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S15. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

WATER HEATING ONLY

[ONLY ASK IF H5, H5a, H6, H7, H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY OR W5a=EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]

S16. In addition to the cost of converting the water heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $100 a year for a customer with natural gas water heating. This charge would be in addition to Union's charges for gas and delivery to you. After accounting for the surcharge, you still may save up to $100 a year on your water heating costs. **Considering this, how likely are you to convert your water heating to natural gas? Would you say...?**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SECTION E: Expansion Timeline

[ASK E1 AND E2 IF S10 OR S11 OR S12 OR S13 OR S14 OR S15 OR S16= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]
E1. You indicated that you are likely to convert to natural gas. Assuming gas service is available after December 2015, when would you likely convert?
(READ LIST)

Within the first 12 months
Within 1 to 2 years
Within 2 to 3 years
After 3 years

FORUM
RESEARCH INC.

E2. I am going to read you a list of appliances that could be powered by natural gas. For each appliance, please tell me if you would be extremely interested, very interested, interested, not very interested or not at all interested in natural gas for the appliance.

[READ; RANDOMIZE]
Fireplace
Oven, range or stove
Clothes dryer
BBQ
Other (**SPECIFY**)

[SCALE]
Extremely interested
Very interested
Interested
Not very interested
Not at all interested

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

ASK QUESTIONS IN SECTION D IF SCR5 (2015) = RESIDENCE
SECTION D: Demographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

D1. Which of the following best describes the style of your house? Is it a …?

(READ LIST)
A bungalow or one story ranch
A raised ranch
A split level
A two story
Or a three story house
Some other style

D2. In order to have some idea as to the approximate size of your home in square feet (not including any unfinished basement) can you tell me how many square feet your home is?
[RECORD NUMBER. RANGE: 100 – 10000]

D3. In what year was your house built? Your best estimate is fine.
[RECORD YEAR]

ASK D3a IF COMMUNITY = PRINCE TOWNSHIP OR COMMUNITY = LAMBTON SHORES.
D3a. Which statement best describes the occupancy of this dwelling?

(READ LIST)
Occupied all-year round
Occupied mostly in the summer months
Occupied mostly in the winter months
Occupied occasionally year round

[SKIP TO D4 IF D3A = OCCUPIED ALL YEAR ROUND, ELSE CONTINUE]

D3b. For approximately how many months did you use this residence during 2014?

(RECORD NUMBER OF MONTHS)
[SCALE: 1-12]

FORUM
RESEARCH INC.

D4. How many adults 18 years or over do you have living in your household, including yourself?

[RECORD NUMERIC RESPONSE. RANGE: 1 TO 20]

D5. And how many children 17 years or younger, if any, do you have living in your household?

[RECORD NUMERIC RESPONSE. RANGE: 0 TO 20]

D6. In what year were you born?

[RECORD YEAR. RANGE: 1900 TO 1993]

[ASK D6a IF REFUSE/DON'T KNOW AT D6, ELSE SKIP TO D7]

D6a. Can you please tell me into which of the following age groups you fall? Are you…?

(READ LIST UNTIL RESPONSE GIVEN)
18 to 24
25 to 34
35 to 44
45 to 54
55 to 64
65 or over

D7. And lastly, which of the following best describes your total household income before taxes? Please stop me when I reach your category. Is it…?

(READ LIST)
Under $20,000
$20,000 to less than $40,000
$40,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 to less than $120,000
$120,000 to less than $140,000
$140,000 or more

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

ASK QUESTIONS IN SECTION E IF SCR5 (2015) = BUSINESS
SECTION E: Firmographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

E1. How many buildings (are at this location?)
NOTE: IF LESS THAN ONE BUILDING, E.G. IF LOCATED IN A BUILDING OR SHOPPING PLAZA, ENTER “PART OF A BUILDING”
1,
2,
3,
OTHER (SPECIFY),
PART OF A BUILDING,
REFUSED
DON’T KNOW

E2. What is the approximate square footage of the indoor floor space (at this location of the first/second/third building), including basement and storage, but not including parking or loading areas?
Please consider only the area that is affected by a heating system.
[RECORD NUMBER]

E3. What is the age of the building at this location (of the first/second/third building)?

1 YEAR OR LESS,
2 TO 5 YEARS,
6 TO 10 YEARS,
11 TO 20 YEARS,
21 TO 30 YEARS,
31 TO 40 YEARS,
MORE THAN 40 YEARS OLD,
DON’T KNOW

DB3. How many floors does the building have?

(SPECIFY)

Thank you for your feedback. We appreciate your willingness to participate in this survey.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Record of Contact

	Lambton Shores
Complete	**104**
Refusal	83
Callback	0
Answering machine	21
Vacation	1
Terminate partway	8
Language	2
Not in	10
Wrong number	29
Duplicate	1
Disqualified	19
Total	**278**

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

180 Bloor Street West
Suite 1400
Toronto, Ontario
M5S 2V6
T (905) 960-3255
F (416) 960-6061
www.forumresearch.com

FORUM
RESEARCH INC.

Gas Pipeline Expansion Study - Milverton

Research Report Prepared for: Union Gas Limited

July 22, 2015

FORUM
RESEARCH INC.

Table of Contents

Background	3
Research Objectives	3
Methodology	3
Highlights	4
Findings	5
Space Heating	5
Water Heating	7
Likelihood to Convert with Surcharge	8
Conversion Time	9
Other Appliances	10
Demographics and Housing Characteristics	10
Appendix: Questionnaire and Record of Contact	13

Background

Union Gas (Union) operates in northern, southwestern, and eastern Ontario delivering natural gas services to over 1.3 million residential, commercial, and industrial customers in more than 400 communities. However, the town of Milverton, located in southwestern Ontario is not currently serviced by Union. Given the operating cost advantages of natural gas, Union believes that there is significant interest in converting to natural gas, particularly for space and water heating. Union is reviewing the feasibility of extending the gas pipeline that will service the citizens of Milverton Ontario.

In addition to the cost of converting space and water heating equipment to natural gas, households typically are required to make a contribution toward the pipeline capital costs of extending service to the community. Union has developed a volumetric surcharge for those that elect to convert, as a means to overcome the upfront capital cost barrier that households would face upon conversion. Market research in Milverton Ontario is needed to measure the likelihood of converting to natural gas given potential savings, conversion costs and the volumetric surcharge alternative for recovering upfront pipeline extension costs.

Research Objectives

The objective of this research is to ascertain interest in obtaining natural gas service amongst the residential household and commercial business populations of Milverton Ontario. Specifically, this research is designed to:

- Measure the likelihood of converting heating equipment based on a range of typical equipment conversion costs.
- Gauge interest in switching to natural gas water heating based on a range of typical equipment conversion costs.
- Measure the impact on likelihood of conversion based on a volumetric surcharge (cents per m^3) that would apply to natural gas consumption following conversion.

Methodology

To achieve the research objectives, Union retained the services of Forum Research, a third party research supplier, to conduct the quantitative study. A total of 201 telephone interviews were completed from a list of 608 home and business owners in Milverton between April 16th and April 26th, yielding a +/- 5.7% margin of error at the 95% confidence level. The level of completes represents a 33% response rate.

Highlights

- Overall, 57% of respondents are "extremely" or "very likely" to convert their **space heating** systems to natural gas based on the cost of converting their equipment.
  - Oil forced air and propane forced air systems currently account for 33% and 30% respectively of all space heating systems in Milverton (13% electric heat and 24% "other" sources such as boilers, wood, geothermal heating or something else).

- Almost half of respondents (45%) are likely to convert their **water heaters** to natural gas.
  - Virtually all Milverton respondents own their water heaters (94%) and the majority currently uses electricity as the main fuel source (73%).

- With an additional contribution to pipeline construction, 45% of respondents overall are "extremely" or "very likely" to convert their space heating systems and/or water heaters to natural gas.

- Of those likely to convert their space heating systems and/or water heaters to natural gas if a surcharge was required, 74% are extremely/very likely to convert within the first 12 months, 21% are extremely/very likely to convert within 1-2 years, and the remaining 5% are extremely/very likely to convert within 2-3 years.

- Among respondents who are likely to convert their space heating systems and/or water heaters to natural gas, 42% are also interested in converting their BBQs to natural gas, followed by 33% for fireplaces, 28% for ovens/stoves and 24% for clothes dryers.

Findings

Space Heating

This study indicates that the most prevalent space heating systems used in Milverton are oil forced air (33%) and propane forced air (30%). Electric heating (forced air or baseboard) heats 13% of Milverton households. The remaining 1-in-4 households (24%) use a variety of other heating sources (oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else).

Propane forced air systems tend to have been installed more recently than oil forced air or electric heating systems (49% are five years old or less). Therefore, propane users are least likely to replace their space heating systems in the next two years (18% are extremely likely/very likely/likely to replace them).

Electric forced air/electric baseboard systems tend to be the oldest systems (42% are 25 years and older), followed by oil forced air systems. Therefore, users are far more likely to replace them in the next two years (54% and 42% are extremely likely/very likely/likely to replace them respectively), along with other heating sources (53% extremely likely/very likely/likely to replace them).

Overall, 57% of respondents would be “extremely” or “very likely” to convert their space heating systems to natural gas (when given the equipment conversion cost only). Propane forced air users are more likely to convert (72%) than respondents with other systems.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Table 1: Space Heating
Base: All respondents

	Total (n=201)	Oil Forced Air (n=66)	Propane Forced Air (n=61)	Electric Forced Air/Electric Baseboard (n=26)	Other* (n=48)
Penetration		33%	30%	13%	24%
Likely to replace in the next 2 years (Top 3-Extremely/very/likely to replace)	39%	42%	18%	54%	53%
Age of heating system					
5 years or less	28%	8%	49%	8%	38%
6 to 10 years	25%	24%	30%	8%	28%
11 to 15 years	19%	30%	8%	19%	15%
16 to 25 years	13%	15%	8%	23%	9%
25+ years	15%	18%	3%	42%	11%
Top 2-Extremely/very likely to convert to NG (Equipment conversion cost only)	**57%**	**56%**	**72%**	**46%**	**46%**
Top 3-Extremely/very/likely to convert to NG (Equipment conversion cost only)	**81%**	**76%**	**92%**	**81%**	**73%**
Extremely likely	39%	41%	49%	31%	29%
Very likely	18%	15%	23%	15%	17%
Likely	24%	20%	20%	35%	27%
Not very likely	9%	11%	3%	11%	13%
Not at all likely	7%	9%	3%	4%	13%

* No heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump, or something else.

Those not likely to convert their space heating system to natural gas cite cost and a preference for/satisfaction with their current heating systems as the main barriers.

Table 2: Reasons unlikely to convert space heating system to Natural Gas
Base: Those not very/not at all likely to convert

	Have Forced Air (Oil, Electric, Propane) or Electric Baseboard (n=21)	Other Source* (n=12)
Too expensive	48%	25%
Prefer current heating system	19%	-
Don't believe promise of savings	14%	-
Not interested/No plans to change	5%	17%
Not interested now/maybe in future	5%	-
Plan on building a new home/moving	5%	-
Current heating system is new	5%	-
Senior/too old to change	5%	-
Not worth it	-	8%
Other	-	75%

* No Heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else
Totals may exceed 100% due to multiple mentions
Question: You indicated that you are unlikely to convert your heating system to natural gas. Can you tell me why? (PROBE) Are there any other reasons?

Water Heating

Virtually all Milverton respondents own their water heaters (94%). The majority use electricity as the main fuel source (73%), followed by propane (20%).

About half of respondents (48%) have had their water heaters for five years or less. Propane water heaters tend to have been installed more recently than electric heaters (65% vs. 44% within the past 5 years).

Overall, 45% of respondents would be "extremely" or "very likely" to convert their water heaters to natural gas. Those who currently own propane water heaters are more interested in natural gas than those who own electric heaters (61% vs. 38% extremely/very likely to convert).

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Table 3: Water Heating
Base: All respondents

	Total (n=201)	Propane (n=40)	Electricity (n=146)	Other Source* (n=15)
Penetration		20%	73%	7%
Own water heater	94%	90%	96%	80%
Age of water heater				
5 years or less	48%	65%	44%	40%
6 to 10 years	23%	28%	24%	7%
11 to 15 years	14%	3%	14%	47%
16+ years	11%	3%	14%	7%
	Rent (n=13)		Own (n=188)	
Extremely/very likely to convert water heater to NG **	**45%**			
Extremely likely	31%		29%	
Very likely	31%		15%	
Likely	23%		26%	
Not very likely	15%		20%	
Not at all likely	-		8%	

* Oil, geothermal/heat pump or something else
** Total who own or rent.

Likelihood to Convert with Surcharge

Respondents who indicated they are likely to convert either space or water heating systems to natural gas were asked their likelihood to convert if an additional financial contribution toward pipeline construction were required, in addition to the equipment conversion cost. The additional pipeline surcharge would be 23 cents per cubic metre for a 5 to 10 year period. For the typical residential home, this would add to about $350 to $450 a year (about $100 per year if converting the water heater only).

Overall, 45% of respondents would be “extremely” or “very likely” to convert their space heating systems and/or water heaters to natural gas (knowing the equipment conversion cost and the surcharge) and 24% would be “extremely” likely to convert. Likelihood to convert is strongest among those currently on oil and propane forced air (61% and 67% respectively).

FORUM RESEARCH INC.

Table 4: Likely to Convert – With Surcharge
Base: Those likely to convert to Natural Gas (Equipment conversion cost only)

	TOTAL POPULA-TION (n=201)	Likely to Convert Both Space Heater and Water Heater (Extremely/Very/Likely) (QS10 to S12)				Likely to Convert Space Heater Only (Extremely/Very/Likely) (QS13 to S15)	Likely to Convert Water Heating only (Extremely/Very/Likely) (QS16)
		Oil Forced Air (n=46)	Propane Forced Air (n=43)	Electric Forced Air/ Electric Baseboard (n=17)	Other* (n=30)	(see Note 1) (n = 25)	Water Heater (Own or Rent) (n=5)**
Likelihood to convert with surcharge							
Top 3 – Extremely/ Very/Likely	**74%**	**87%**	**95%**	**88%**	**97%**	**76%**	**--**
Top 2 – Extremely/ Very likely	**45%**	**61%**	**67%**	**41%**	**50%**	**36%**	**--**
Extremely likely	**24%**	**30%**	**42%**	**18%**	**37%**	**8%**	**--**
Very likely	**20%**	**30%**	**26%**	**24%**	**13%**	**28%**	**--**
Likely	**29%**	**26%**	**28%**	**47%**	**47%**	**40%**	**--**
Not very likely	**5%**	**7%**	**2**	**6%**	**3%**	**24%**	**--**
Not at all likely	**1%**	**2%**	**-**	**6%**	**-**	**0%**	**--**

* No Heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else
** Extremely small base, details not reported when n < 10.
Note 1: Consists of Oil Forced Air/Propane Forced Air/Electric Forced Air/ Electric Baseboard/Other.
Note 2: The percentages shown are rounded. Some percentages for individual points on the scale may not add up to the Top-2 and Top-3 values due to rounding error.

Conversion Time

Respondents who indicated they are likely (extremely, very, or likely) to convert space heating systems and/or water heaters to natural gas if a surcharge was required were asked when they are likely to do so if natural gas is available after December 2015.

For those indicating extremely/very/likely to convert, 74% are extremely/very likely to convert within the first 12 months, 21% are extremely/very likely to convert within 1-2 years, and the remaining 5% are extremely/very likely to convert within 2-3 years.

Other Appliances

Respondents who are likely to convert their space heating systems and/or water heaters to natural gas were asked if they would be interested in converting other appliances to natural gas as well. BBQs are the appliance that they would be most interested in converting to natural gas (42% extremely or very interested). One-in-three would be interested in converting their fireplaces (33%) and about 1-in-4 show an interest in converting their ovens/stoves (28%) or clothes dryers (24%) to natural gas.

Table 5: Interest in Converting Other Appliances to Natural Gas
Base: Those likely to convert to Natural Gas (with surcharge)

	BBQ (n=148)	Fireplace (n=148)	Oven/ Range/Stove (n=148)	Clothes Dryer (n=148)
Extremely/very interested in converting other appliances	42%	33%	28%	24%
Extremely interested	19%	17%	16%	13%
Very interested	23%	16%	12%	11%
Interested	27%	24%	37%	35%
Not very interested	11%	7%	18%	18%
Not at all interested	15%	26%	14%	18%
Don't know/not stated	5%	9%	4%	5%

Demographics and Housing Characteristics

One and two storey houses make up the majority of homes in Milverton, accounting for 77% of all respondent households. The average house size is 1894 square feet and the age of the home varies: about 1-in-3 homes (30%) are under 35 years of age and 39% are at least 65 years old.

48% of Milverton respondents are 55 years or older, while only 11% are under 35 years of age. The majority of residences house 1 or 2 adults (78%) and no children (64%).

About three-quarters of households (72%) have incomes of $40,000 or more: 36% earn $40,000 to $80,000 and 36% earn more than $80,000. Over 1-in-4 households (28%) reported income between $20,000 and $60,000.

Considering conversion cost only, in aggregate, 62% of respondents are "extremely" or "very likely" to convert any of their space heating and/or water heating to natural gas (both space heater and water heater, space heating only, and water heating only). Those who are more likely to convert tend to be:

- Younger respondents (70% of 18 to 64 year olds vs. 39% of those 65 years or older), and

FORUM
RESEARCH INC.

- Higher income households (76% with $60,000-$100,000 incomes vs. 51% with incomes below $60,000).

When both conversion cost and volumetric surcharge are considered, in aggregate, 45% of respondents are "extremely" or "very likely" to convert any of their space heating and/or water heating to natural gas (both space heater and water heater, space heating only, and water heating only). Those who are more likely to convert tend to be:

- younger respondents (50% of 18 to 64 year olds vs. 29% of those 65 years or older), and
- higher income households (58% with $60,000-$100,000 incomes vs. 67% with incomes below $60,000).

Other demographic attributes of interest are that:

- Smaller houses are more likely to use oil forced air for space heating than larger ones (56% of houses less than 1000 square feet, 47% of houses 1000-1500 square feet, and 15% of large houses over 2,000 square feet).

- Older houses are more likely to use oil forced air for space heating (45% for houses built in 1950 or earlier and 12% for houses built in 1981 or later).

- Newer houses are more likely to use electric or propane water heaters:
    - 14% of houses built in 1950 or earlier and 39% houses built in 1981 or later use propane for water heating.

    - 79% of houses built in 1950 or earlier and 53% houses built in 1981 or later use electricity for water heating.

FORUM
RESEARCH INC.

Table 6: Demographics – Residence
Base: All "Residence" Respondents

	Total (n=198)
Building Type	
Two storey	44%
Bungalow/One storey ranch	33%
Three storey house	7%
Split level	6%
Raised ranch	3%
Other	8%
Approximate size of home (in sq. feet)	
Less than 1,000	5%
1,000 to 1,500	23%
1,501 to 2,000	31%
Over 2,000	20%
Don't know	21%
Average size	**1894 sq. ft.**
Age of home	
0 to 34 years	30%
35 to 64 years	23%
65+ years	39%
Don't know/not stated	8%
Age of respondent	
18 to 34 years	11%
35 to 44 years	20%
45 to 54 years	20%
55 to 64 years	23%
65+ years	25%
Number of adults 18 years or older living in house	
1-2	78%
3+	21%
Number of children 17 years or younger living in house	
0	64%
1-2	29%
3+	7%
Total Household Income	
Less than $40,000	9%
40,000 to $80,000	36%
More than $80,000	36%
Refused	19%

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Appendix: Questionnaire and Record of Contact

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

3 Community System Expansion Questionnaire
April 13th, 2015

Good morning/evening. My name is ______ and I am calling from Forum Research on behalf of Union Gas. We are conducting a survey to assist in determining whether natural gas will be extended to your area. You may have previously participated in a survey on this issue, but the results of this particular survey are very important, as they will help us to evaluate whether extending the gas system can be proposed to the Ontario Energy Board in the next year. I want to assure you that we are not selling anything and the information you provide to us will be aggregated with others for reporting purposes.

SCR1. Are you 18 years or older and the person responsible for making energy decisions for the property at (SPECIFY ADDRESS)?

Yes, speaking
No, I'll get them
No, not available
[IF YES, SPEAKING, CONTINUE]
[IF NO, I'LL GET THEM, REINTRODUCE]
[IF NO, NOT AVAILABLE, SCHEDULE CALLBACK THEN THANK AND TERMINATE]
[IF NOT AT THIS LOCATION, RECORD DECISION MAKER'S CONTACT INFORMATION (FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE) THANK AND TERMINATE. ADD REFERRAL TO CONTACT LIST]

SCR3. Do you own or rent this property at (SPECIFY ADDRESS)?
Own
Rent

[IF OWN, CONTINUE]
[IF RENT, GET CONTACT INFO – FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE - OF OWNER AND TERMINATE. IF REF, THANK AND TERMINATE]

SCR4. **(DO NOT ASK) RECORD GENDER**
Male
Female

SCR5 (2015). Is this a residence or a business?
Residence
Business
Both Residence and a Business

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

IF (COMMUNITY = Lambton Shores OR COMMUNITY = Prince Township) AND SCR5 (2015) = Business THEN THANK AND TERMINATE.
NOTE:
IF SCR5 (2015) = "BOTH RESIDENCE AND A BUSINESS" THEN CONSIDER IT A "RESIDENCE" FOR INTERVIEW PURPOSE.

SECTION H: Home Heating

H1. What type of system provides the primary source of heat for this premise? Is it…?

[READ, RANDOMIZE]
Oil Forced Air
Electric Forced Air
Propane Forced Air
Electric Baseboard
Oil Boiler (Hot Water Radiators)
Propane Boiler (Hot Water Radiators)
No heating system
Or Something Else (SPECIFY)

IF H1 = NO HEATING SYSTEM, SKIP TO H8, ELSE CONTINUE
Other **[SPECIFY]**

H2. How old is your heating system? **(READ)**

5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

H3. How likely are you to replace your heating system in the next 2 years? Are you…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

[ASK H5 IF H1 = OIL FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H5a]

H5. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $2,000 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H5a IF H1 = ELECTRIC FORCE AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H6]

H5a. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H6 IF H1 = PROPANE FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H7]

H6. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to natural gas is likely in the range of $500 to $1,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H7 IF H1 = ELECTRIC BASEBOARD, ELSE SKIP TO INSTRUCTIONS BEFORE H8]

H7. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a high efficiency natural gas furnace is likely to be about $10,000 depending on the specific style and size of your premise. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK H8 IF H1 = NO HEATING SYSTEM, OIL BOILER, PROPANE BOILER OR SOMETHING ELSE.]

H8. Installing a high efficiency natural gas furnace is likely to cost about $4,000-$5,000 if you already have forced air ductwork and $10,000 if it doesn't. However, with natural gas, you may save up to $2,000 off the annual cost of heating with oil, propane or electricity. If natural gas service was extended to your area, how likely are you to install a natural gas heating system? Would you say you are...?
(READ)

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

FORUM
RESEARCH INC.

[ASK H9A IF H5/H5a/6/7 = NOT VERY LIKELY *OR* NOT AT ALL LIKELY]
H9a. You indicated that you are unlikely to convert your heating system to natural gas. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home (or facility) / moving
Too expensive
Other: **[SPECIFY]**

[ASK H9B IF H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY]
H9b. You indicated that you are unlikely to install a natural gas space heating system. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
This is a cottage occupied only in the summer
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home/ moving
Too expensive
Other: **[SPECIFY]**

SECTION W: Water Heating

ASK ALL
Now, I would like to ask you a few questions about your water heater.

W1. What is the MAIN fuel source for heating your water?

Propane
Oil
Electricity
Other: **[SPECIFY]**

FORUM
RESEARCH INC.

W2. How old is your water heater?

(READ)
5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

W3. Is your water heater owned or rented?

Owned
Rented

[ASK W5 IF W3=OWNED]
W5. The purchase and installation of a typical natural gas water heater costs about $1600 depending on the complexity of the installation. However, with natural gas, you may save up to $200 off of your water heating costs every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK W5a IF W3=RENTED]
W5a. Natural Gas water heaters can also be rented. Typical monthly rental rates range from $13 per month to $24 per month. Depending on the specific style of your premises, the property owner may incur additional expenses for the conversion. However, with natural gas, you may save up to $200 off your water heating bill every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are... ? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

SECTION S: CONVERSION LIKELIHOOD WITH VOLUMETRIC SURCHARGE

SPACE AND WATER HEATING

INTERVIEWER NOTE FOR QUESTIONS S10 – S16:
IF RESPONDENT ASKS ABOUT THE OPTION OF A GOVERNMENT LOAN OR GRANT FOR CONSTRUCTING THE GAS PIPELINE, INTERVIEWER SHOULD MENTION THAT THIS IS NOT PART OF THE UNION GAS PROPOSAL AT THIS TIME.

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S10. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1750 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S11. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating costs. **Considering this, how**

likely are you to convert your space heating and water heating to natural gas? Would you say...?
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5A = EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S12. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SPACE HEATING ONLY

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S13. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1650 a year on your

FORUM
RESEARCH INC.

heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF OR H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S14. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5a= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S15. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

WATER HEATING ONLY

[ONLY ASK IF H5, H5a, H6, H7, H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY OR W5a=EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]

S16. In addition to the cost of converting the water heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $100 a year for a customer with natural gas water heating. This charge would be in addition to Union's charges for gas and delivery to you. After accounting for the surcharge, you still may save up to $100 a year on your water heating costs. **Considering this, how likely are you to convert your water heating to natural gas? Would you say...?**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SECTION E: Expansion Timeline

[ASK E1 AND E2 IF S10 OR S11 OR S12 OR S13 OR S14 OR S15 OR S16= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]
E1. You indicated that you are likely to convert to natural gas. Assuming gas service is available after December 2015, when would you likely convert?
(READ LIST)

Within the first 12 months
Within 1 to 2 years
Within 2 to 3 years
After 3 years

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

E2. I am going to read you a list of appliances that could be powered by natural gas. For each appliance, please tell me if you would be extremely interested, very interested, interested, not very interested or not at all interested in natural gas for the appliance.

[READ; RANDOMIZE]
Fireplace
Oven, range or stove
Clothes dryer
BBQ
Other (**SPECIFY**)

[SCALE]
Extremely interested
Very interested
Interested
Not very interested
Not at all interested

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

ASK QUESTIONS IN SECTION D IF SCR5 (2015) = RESIDENCE
SECTION D: Demographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

D1. Which of the following best describes the style of your house? Is it a …?

(READ LIST)
A bungalow or one story ranch
A raised ranch
A split level
A two story
Or a three story house
Some other style

D2. In order to have some idea as to the approximate size of your home in square feet (not including any unfinished basement) can you tell me how many square feet your home is?
[RECORD NUMBER. RANGE: 100 – 10000]

D3. In what year was your house built? Your best estimate is fine.
[RECORD YEAR]

ASK D3a IF COMMUNITY = PRINCE TOWNSHIP OR COMMUNITY = LAMBTON SHORES.
D3a. Which statement best describes the occupancy of this dwelling?

(READ LIST)
Occupied all-year round
Occupied mostly in the summer months
Occupied mostly in the winter months
Occupied occasionally year round

[SKIP TO D4 IF D3A = OCCUPIED ALL YEAR ROUND, ELSE CONTINUE]

D3b. For approximately how many months did you use this residence during 2014?

(RECORD NUMBER OF MONTHS)
[SCALE: 1-12]

D4. How many adults 18 years or over do you have living in your household, including yourself?

[RECORD NUMERIC RESPONSE. RANGE: 1 TO 20]

D5. And how many children 17 years or younger, if any, do you have living in your household?

[RECORD NUMERIC RESPONSE. RANGE: 0 TO 20]

D6. In what year were you born?

[RECORD YEAR. RANGE: 1900 TO 1993]

[ASK D6a IF REFUSE/DON'T KNOW AT D6, ELSE SKIP TO D7]

D6a. Can you please tell me into which of the following age groups you fall? Are you…?

(READ LIST UNTIL RESPONSE GIVEN)
18 to 24
25 to 34
35 to 44
45 to 54
55 to 64
65 or over

D7. And lastly, which of the following best describes your total household income before taxes? Please stop me when I reach your category. Is it…?

(READ LIST)
Under $20,000
$20,000 to less than $40,000
$40,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 to less than $120,000
$120,000 to less than $140,000
$140,000 or more

FORUM
RESEARCH INC.

ASK QUESTIONS IN SECTION E IF SCR5 (2015) = BUSINESS
SECTION E: Firmographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

E1. How many buildings (are at this location?)
NOTE: IF LESS THAN ONE BUILDING, E.G. IF LOCATED IN A BUILDING OR SHOPPING PLAZA, ENTER "PART OF A BUILDING"
1,
2,
3,
OTHER (SPECIFY),
PART OF A BUILDING,
REFUSED
DON'T KNOW

E2. What is the approximate square footage of the indoor floor space (at this location of the first/second/third building), including basement and storage, but not including parking or loading areas?
Please consider only the area that is affected by a heating system.
[RECORD NUMBER]

E3. What is the age of the building at this location (of the first/second/third building)?

1 YEAR OR LESS,
2 TO 5 YEARS,
6 TO 10 YEARS,
11 TO 20 YEARS,
21 TO 30 YEARS,
31 TO 40 YEARS,
MORE THAN 40 YEARS OLD,
DON'T KNOW

DB3. How many floors does the building have?

(SPECIFY)

Thank you for your feedback. We appreciate your willingness to participate in this survey.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Record of Contact

	Milverton
Complete	**201**
Refusal	105
Callback	11
Answering machine	10
Vacation	0
Terminate partway	5
Language	13
Not in	10
Wrong number	22
Duplicate	5
Dialer - No answer	78
Dialer - Busy	5
Dialer - Operator intercept	20
Dialer - Dropped call	15
Dialer - Answering machine	78
Dialer - Fax/modem	0
Disqualified	22
Other	8
Total	**608**

180 Bloor Street West
Suite 1400
Toronto, Ontario
M5S 2V6
T (905) 960-3255
F (416) 960-6061
www.forumresearch.com

FORUM
RESEARCH INC.

Gas Pipeline Expansion Study
- Prince Township -

Research Report Prepared for: Union Gas Limited

July 22, 2015

Marketing Research and Intelligence Association
Accredited Gold Seal Corporate Member
MRIA ARIM
L'Association de la Recherche et de l'Intelligence Marketing

FORUM
RESEARCH INC.

Table of Contents

Background	3
Research Objectives	3
Methodology	3
Highlights	4
Findings	5
Space Heating	5
Water Heating	7
Likelihood to Convert with Surcharge	8
Conversion Time	9
Other Appliances	9
Demographics and Housing Characteristics	10
Appendix: Questionnaire and Record of Contact	12

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Background

Union Gas (Union) operates in northern, southwestern, and eastern Ontario delivering natural gas services to over 1.3 million residential, commercial, and industrial customers in more than 400 communities. However, Prince Township, located in northern Ontario is not currently serviced by Union. Given the operating cost advantages of natural gas, Union believes that there is significant interest in converting to natural gas, particularly for space and water heating. Union is reviewing the feasibility of extending the gas pipeline that will service the citizens of Prince Township Ontario.

In addition to the cost of converting space and water heating equipment to natural gas, households typically are required to make a contribution toward the pipeline capital costs of extending service to the community. Union has developed a volumetric surcharge for those that elect to convert, as a means to overcome the upfront capital cost barrier that households would face upon conversion. Market research in Prince Township Ontario is needed to measure the likelihood of converting to natural gas given potential savings, conversion costs and the volumetric surcharge alternative for recovering upfront pipeline extension costs.

Research Objectives

The objective of this research is to ascertain interest in obtaining natural gas service amongst the residential household population of Prince Township Ontario. Specifically, this research is designed to:

- Measure the likelihood of converting heating equipment based on a range of typical equipment conversion costs.
- Gauge interest in switching to natural gas water heating based on a range of typical equipment conversion costs.
- Measure the impact on likelihood of conversion based on a volumetric surcharge (cents per m^3) that would apply to natural gas consumption following conversion.

Methodology

To achieve the research objectives, Union retained the services of Forum Research, a third party research supplier, to conduct the quantitative study. A total of 126 telephone interviews were completed from a list of 368 home and business owners in Prince Township between April 16th and April 26th, yielding a +/- 7.1% margin of error at the 95% confidence level. The level of completes represents a 34% response rate.

FORUM
RESEARCH INC.

Highlights

- Overall, 69% of respondents are "extremely" or "very likely" to convert their **space heating** systems to natural gas based on the cost of converting their equipment.
    - The most prevalent space heating system currently used in Prince Township is electric heating (forced air or baseboard) (41%). Oil forced air and "other" sources (boilers, wood, geothermal, etc.) are used by 24% and 21% of households respectively. Propane forced air heats 14% of Prince Township households.

- Over half of respondents (57%) are likely to convert their **water heaters** to natural gas.
    - Majority of Prince Township respondents own their water heaters (79%) and currently use electricity as the main fuel source (86%).

- With an additional contribution to pipeline construction, 48% of respondents overall are "extremely" or "very likely" to convert their space heating systems and/or water heaters to natural gas.

- Of those likely to convert their space heating systems and/or water heaters to natural gas if a surcharge was required, 75% are extremely/very likely to convert within the first 12 months, 19% are extremely/very likely to convert within 1-2 years, and the remaining 5% are extremely/very likely to convert within 2-3 years.

- Among respondents who are likely to convert their space heating systems and/or water heaters to natural gas, 45% are also interested in converting their BBQs or their fireplaces to natural gas, followed by 36% for ovens/stoves and 29% for clothes dryers.

- Virtually all Prince Township homes are used year-round (99%).

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Findings

Space Heating

This study indicates that the most prevalent space heating system used in Prince Township is electric heating (forced air or baseboard) (41%). Oil forced air and "other" sources (oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else) are used by 24% and 21% of households respectively. Propane forced air heats 14% of Prince Township households.

Propane forced air systems tend to have been installed more recently than other heating systems (72% are five years old or less). Therefore, propane users are least likely to replace their space heating systems in the next two years (28% are extremely likely/very likely/likely to replace them).

Overall, 69% of respondents would be "extremely" or "very likely" to convert their space heating systems to natural gas (when given the equipment conversion cost only), and this is relatively consistent regardless of their current sources of heat. However, "extremely likely to convert" scores suggest that propane forced air users are more likely to convert (61%) than oil or electric forced air/electric baseboard users (37% and 29% respectively).

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Table 1: Space Heating
Base: All respondents

	Total (n=126)	Oil Forced Air (n=30)	Propane Forced Air (n=18)	Electric Forced Air/Electric Baseboard (n=51)	Other* (n=27)
Penetration		24%	14%	41%	21%
Likely to replace in the next 2 years (Top 3-Extremely/very/likely to replace)	65%	80%	28%	67%	70%
Age of heating system					
5 years or less	28%	17%	72%	22%	22%
6 to 10 years	21%	40%	11%	10%	26%
11 to 15 years	14%	20%	6%	14%	15%
16 to 25 years	10%	10%	6%	12%	7%
25+ years	27%	13%	6%	41%	30%
Top 2-Extremely/very likely to convert to NG (Equipment conversion cost only)	**69%**	**77%**	**78%**	**60%**	**70%**
Top 3-Extremely/very/likely to convert to NG (Equipment conversion cost only)	**88%**	**90%**	**100%**	**84%**	**85%**
Extremely likely	40%	37%	61%	29%	52%
Very likely	29%	40%	17%	31%	18%
Likely	19%	13%	22%	24%	15%
Not very likely	6%	3%	-	12%	- %
Not at all likely	5%	7%	-	4%	7%

* No heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump, or something else

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

Those not likely to convert to natural gas cite cost as the main barrier.

Table 2: Reasons unlikely to convert space heating system to Natural Gas
Base: Those not very/not at all likely to convert

	Have Forced Air (Oil, Electric, Propane) or Electric Baseboard (n=11)	Other Source* (n=2)**
Too expensive	45%	-
Not worth it	18%	-
Prefer current heating system	9%	-
Not interested/No plans to change	9%	-
Not interested now/maybe in future	9%	-
Plan on building a new home/moving	9%	-
Current heating system is new	9%	-

* No Heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else
*** Extremely small base*
Totals may exceed 100% due to multiple mentions
Question: You indicated that you are unlikely to convert your heating system to natural gas. Can you tell me why? (PROBE) Are there any other reasons?

Water Heating

Just over three-quarters of Prince Township respondents own their water heaters (79%). The vast majority use electricity as the main fuel source (86%). "Other sources" including propane, oil or geothermal heat are used by 14% of households.

One-third of respondents (33%) have had their water heaters for five years or less. Though base sizes are small, electric heaters appear to be older than some of the alternative sources (31% vs. 44% installed within the past 5 years), and this is consistent with other areas.

Overall, 57% of respondents would be "extremely" or "very likely" to convert their water heaters to natural gas, and this is relatively consistent among both owners and renters of their water heaters.

FORUM
RESEARCH INC.

Table 3: Water Heating
Base: All respondents

	Total (n=126)	Electricity (n=108)	Other Source* (n=18)
Penetration		86%	14%
Own water heater	79%	77%	89%
Age of Water Heater			
5 years or less	33%	31%	44%
6 to 10 years	25%	24%	28%
11 to 15 years	25%	25%	22%
16+ years	18%	19%	6%

	Own (n=99)	Rent (n=27)
Extremely/very likely to convert water heater to NG **	**57%**	
Extremely likely	34%	33%
Very likely	20%	33%
Likely	23%	15%
Not very likely	9%	7%
Not at all likely	10%	7%

* Oil, propane, geothermal/heat pump or something else
** Total who own or rent.

Likelihood to Convert with Surcharge

Respondents who indicated they are likely to convert either space or water heating systems to natural gas were asked their likelihood to convert if an additional financial contribution toward pipeline construction were required, in addition to the equipment conversion cost. The additional pipeline surcharge would be 23 cents per cubic metre for a 5 to 10 year period. For the typical residential home, this would add to about $350 to $450 a year (about $100 per year if converting the water heater only).

Overall, 48% of respondents would be “extremely” or “very likely” to convert their space heating systems and/or water heaters to natural gas (knowing the equipment conversion cost and the surcharge) and 25% would be “extremely” likely to convert.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM RESEARCH INC.

Table 4: Likely to Convert – With Surcharge
Base: Those likely to convert to Natural Gas (Equipment conversion cost only)

		Likely to Convert Both Space Heater and Water Heater (Extremely/Very/Likely) (QS10 to S12)				Likely to Convert Space Heater Only (Extremely/Very/Likely) (QS13 to S15)	Likely to Convert Water Heating only (Extremely/Very/Likely) (QS16)
	TOTAL POPULA-TION (n=126)	Oil Forced Air (n=21)	Propane Forced Air (n=14)	Electric Forced Air/ Electric Baseboard (n=39)	Other* (n=22)	(see Note 1) (n = 13)	Water Heater (Own or Rent) (n=3)**
Likelihood to convert with surcharge							
Top 3 – Extremely/ Very/Likely	**80%**	**95%**	**86%**	**87%**	**100%**	**77%**	--
Top 2 – Extremely/ Very likely	**48%**	**67%**	**36%**	**46%**	**68%**	**54%**	--
Extremely likely	25%	33%	29%	18%	45%	23%	--
Very likely	23%	33%	7%	28%	23%	31%	--
Likely	32%	29%	50%	41%	32%	23%	--
Not very likely	4%	5%	7%	5%	-	8%	--
Not at all likely	1%	-	-	3%	-	8%	--

* No Heating system, oil boiler, propane boiler, wood/wood pellets, geothermal/heat pump or something else
** Extremely small base, details not reported when n < 10.
Note 1: Consists of Oil Forced Air/Propane Forced Air/Electric Forced Air/ Electric Baseboard/Other.

Conversion Time

Respondents who indicated they are likely (extremely, very and likely) to convert space heating systems and/or water heaters to natural gas if a surcharge was required were asked when they are likely to do so if natural gas is available after December 2015.

For those indicating extremely/very likely to convert, 75% would do so within the first 12 months, 19% are extremely/very likely to convert within 1-2 years, and the remaining 5% are extremely/very likely to convert within 2-3 years.

Other Appliances

Respondents who are likely to convert their space heating systems and/or water heaters to natural gas were asked if they would be interested in converting other appliances to natural gas as well. About half of respondents would be interested in converting their BBQs or fireplaces (45% each), about 1-in-3 would be interested in converting their ovens/stoves (36%) and over 1-in-4 show an interest in converting their clothes dryers (29%) to natural gas.

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Table 5: Interest in Converting Other Appliances to Natural Gas
Base: Those likely to convert to Natural Gas (with surcharge)

	BBQ (n=101)	Fireplace (n=101)	Oven/ Range/Stove (n=101)	Clothes Dryer (n=101)
Extremely/very interested in converting other appliances	**45%**	**45%**	**36%**	**29%**
Extremely interested	20%	24%	17%	9%
Very interested	25%	21%	19%	20%
Interested	16%	20%	31%	26%
Not very interested	13%	13%	12%	19%
Not at all interested	25%	19%	20%	24%
Don't know/not stated	2%	4%	2%	3%

Demographics and Housing Characteristics

One and two storey houses make up the majority of homes in Prince Township, accounting for 80% of all respondent households. The average house size is 1869 square feet and the vast majority of houses are under 65 years of age (91%). Virtually all homes are used year-round.

58% Prince Township respondents are 55 years or older, while only 8% are under 35 years of age. The majority of residences house 1 or 2 adults (83%) and no children (73%).

Household incomes tend to be relatively high among Prince Township respondents: 43% earn $80,000 or more and 18% earn at least $120,000.

Considering conversion cost only, in aggregate, 76% of respondents are “extremely” or “very likely” to convert any of their space heating and/or water heating to natural gas (both space heater and water heater, space heating only, and water heating only) . Those who are more likely to convert tend to be:

- younger respondents (95% of 18 to 44 year olds vs. 73% of those 45 years or older)
- those with smaller houses (87% with 1,500 square foot houses or smaller vs. 69% of those with larger houses).

FORUM
RESEARCH INC.

Table 6: Demographics – Residence
Base: All "Residence" Respondents

	Total (n=126)
Building Type	
Bungalow/One storey ranch	52%
Two storey	28%
Split level	11%
Raised ranch	6%
Three storey house	2%
Other	2%
Approximate size of home (in sq. feet)	
Less than 1,000	3%
1,000 to 1,500	33%
1,501 to 2,000	22%
Over 2,000	34%
Don't know	7%
Average size	**1869 sq. ft.**
Occupancy of Dwelling	
All-year round	99%
Occasionally year round	1%
Age of home	
0 to 34 years	44%
35 to 64 years	47%
65+ years	3%
Don't know/not stated	6%
Age of respondent	
18 to 34 years	8%
35 to 44 years	10%
45 to 54 years	23%
55 to 64 years	29%
65+ years	29%
Number of adults 18 years or older living in house	
1-2	83%
3+	17%
Number of children 17 years or younger living in house	
0	73%
1-2	22%
3+	6%
Total Household Income	
Less than $40,000	11%
40,000 to $80,000	29%
More than $80,000	43%
Refused	17%

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

FORUM
RESEARCH INC.

Appendix: Questionnaire and Record of Contact

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

3 Community System Expansion Questionnaire
April 13th, 2015

Good morning/evening. My name is ______ and I am calling from Forum Research on behalf of Union Gas. We are conducting a survey to assist in determining whether natural gas will be extended to your area. You may have previously participated in a survey on this issue, but the results of this particular survey are very important, as they will help us to evaluate whether extending the gas system can be proposed to the Ontario Energy Board in the next year. I want to assure you that we are not selling anything and the information you provide to us will be aggregated with others for reporting purposes.

SCR1. Are you 18 years or older and the person responsible for making energy decisions for the property at (SPECIFY ADDRESS)?

Yes, speaking
No, I'll get them
No, not available
[IF YES, SPEAKING, CONTINUE]
[IF NO, I'LL GET THEM, REINTRODUCE]
[IF NO, NOT AVAILABLE, SCHEDULE CALLBACK THEN THANK AND TERMINATE]
[IF NOT AT THIS LOCATION, RECORD DECISION MAKER'S CONTACT INFORMATION (FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE) THANK AND TERMINATE. ADD REFERRAL TO CONTACT LIST]

SCR3. Do you own or rent this property at (SPECIFY ADDRESS)?
Own
Rent

[IF OWN, CONTINUE]
[IF RENT, GET CONTACT INFO – FIRST, LAST, PHONE, ADDRESS – IF POSSIBLE - OF OWNER AND TERMINATE. IF REF, THANK AND TERMINATE]

SCR4. **(DO NOT ASK) RECORD GENDER**
Male
Female

SCR5 (2015). Is this a residence or a business?
Residence
Business
Both Residence and a Business

IF (COMMUNITY = Lambton Shores OR COMMUNITY = Prince Township) AND SCR5 (2015) = Business THEN THANK AND TERMINATE.
NOTE:
IF SCR5 (2015) = "BOTH RESIDENCE AND A BUSINESS" THEN CONSIDER IT A "RESIDENCE" FOR INTERVIEW PURPOSE.

SECTION H: Home Heating

H1. What type of system provides the primary source of heat for this premise? Is it…?

[READ, RANDOMIZE]
Oil Forced Air
Electric Forced Air
Propane Forced Air
Electric Baseboard
Oil Boiler (Hot Water Radiators)
Propane Boiler (Hot Water Radiators)
No heating system
Or Something Else (SPECIFY)

IF H1 = NO HEATING SYSTEM, SKIP TO H8, ELSE CONTINUE
Other **[SPECIFY]**

H2. How old is your heating system? **(READ)**

5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

H3. How likely are you to replace your heating system in the next 2 years? Are you…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

FORUM RESEARCH INC.

[ASK H5 IF H1 = OIL FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H5a]
H5. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $2,000 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H5a IF H1 = ELECTRIC FORCE AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H6]

H5a. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a natural gas high efficiency furnace is in the range of $4,000 to $5,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H6 IF H1 = PROPANE FORCED AIR, ELSE SKIP TO INSTRUCTIONS BEFORE H7]
H6. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to natural gas is likely in the range of $500 to $1,000 depending on the type of equipment you currently have. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK H7 IF H1 = ELECTRIC BASEBOARD, ELSE SKIP TO INSTRUCTIONS BEFORE H8]
H7. Converting your heating system to natural gas requires some initial investment by the property owner. The cost of converting your heating system to a high efficiency natural gas furnace is likely to be about $10,000 depending on the specific style and size of your premise. However, with natural gas, you may save up to $1500 off of your heating cost every year. Considering this, how likely are you to convert your heating system to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK H8 IF H1 = NO HEATING SYSTEM, OIL BOILER, PROPANE BOILER OR SOMETHING ELSE.]

H8. Installing a high efficiency natural gas furnace is likely to cost about $4,000-$5,000 if you already have forced air ductwork and $10,000 if it doesn't. However, with natural gas, you may save up to $2,000 off the annual cost of heating with oil, propane or electricity. If natural gas service was extended to your area, how likely are you to install a natural gas heating system? Would you say you are...?
(READ)

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

[ASK H9A IF H5/H5a/6/7 = NOT VERY LIKELY *OR* NOT AT ALL LIKELY]
H9a. You indicated that you are unlikely to convert your heating system to natural gas. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home (or facility) / moving
Too expensive
Other: **[SPECIFY]**

[ASK H9B IF H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY]
H9b. You indicated that you are unlikely to install a natural gas space heating system. Can you tell me why? (PROBE) Are there any other reasons?

(DO NOT READ)
This is a cottage occupied only in the summer
Don't like natural gas
Not interested/ have no plans to change
Not interested at this time/ maybe in the future
Not worth it
Plan on building a new home/ moving
Too expensive
Other: **[SPECIFY]**

SECTION W: Water Heating

ASK ALL
Now, I would like to ask you a few questions about your water heater.

W1. What is the MAIN fuel source for heating your water?

Propane
Oil
Electricity
Other: **[SPECIFY]**

W2. How old is your water heater?

(READ)
5 years or less
6 to 10 years old
11 to 15 years old
16 to 25 years old
Over 25 years old

W3. Is your water heater owned or rented?

Owned
Rented

[ASK W5 IF W3=OWNED]
W5. The purchase and installation of a typical natural gas water heater costs about $1600 depending on the complexity of the installation. However, with natural gas, you may save up to $200 off of your water heating costs every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are…? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ASK W5a IF W3=RENTED]
W5a. Natural Gas water heaters can also be rented. Typical monthly rental rates range from $13 per month to $24 per month. Depending on the specific style of your premises, the property owner may incur additional expenses for the conversion. However, with natural gas, you may save up to $200 off your water heating bill every year. Considering this, how likely are you to convert your water heater to natural gas? Would you say you are... ? **(READ)**

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

FORUM
RESEARCH INC.

SECTION S: CONVERSION LIKELIHOOD WITH VOLUMETRIC SURCHARGE

SPACE AND WATER HEATING

INTERVIEWER NOTE FOR QUESTIONS S10 – S16:
IF RESPONDENT ASKS ABOUT THE OPTION OF A GOVERNMENT LOAN OR GRANT FOR CONSTRUCTING THE GAS PIPELINE, INTERVIEWER SHOULD MENTION THAT THIS IS NOT PART OF THE UNION GAS PROPOSAL AT THIS TIME.

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S10. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1750 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S11. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating

costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5A = EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR W5a= EXTREMELY LIKELY, VERY LIKELY OR LIKELY]

S12. In addition to the cost of converting the SPACE AND WATER heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $450 a year. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1250 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SPACE HEATING ONLY

[ONLY ASK IF H5 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, OR H8 = EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5=NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S13. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1650 a year

on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF OR H6 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S14. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

[ONLY ASK IF H5a= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY OR H7 =EXTREMELY LIKELY, VERY LIKELY OR LIKELY, AND W5= NOT VERY LIKELY OR NOT AT ALL LIKELY, OR W5a= NOT VERY LIKELY OR NOT AT ALL LIKELY]

S15. In addition to the cost of converting the SPACE heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $350 a year for a customer with natural gas space heating. This charge would depend on your natural gas usage and appear on your bill along with Union's charges for delivery of gas to you. After accounting for the surcharge, you still may save up to $1150 a year on your heating costs. **Considering this, how likely are you to convert your space heating and water heating to natural gas? Would you say...?**

FORUM
RESEARCH INC.

Extremely likely
Very likely
Likely
Not very likely
Not at all likely

WATER HEATING ONLY

[ONLY ASK IF H5, H5a, H6, H7, H8 = NOT VERY LIKELY OR NOT AT ALL LIKELY, AND W5=EXTREMELY LIKELY, VERY LIKELY OR LIKELY OR W5a=EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]

S16. In addition to the cost of converting the water heating equipment in your dwelling, converting customers would be required to make a financial contribution toward the cost of constructing the pipeline through a 23 cent per cubic metre surcharge for a 5-10 year period. For the typical residential home, this would come to about $100 a year for a customer with natural gas water heating. This charge would be in addition to Union's charges for gas and delivery to you. After accounting for the surcharge, you still may save up to $100 a year on your water heating costs. **Considering this, how likely are you to convert your water heating to natural gas? Would you say...?**
Extremely likely
Very likely
Likely
Not very likely
Not at all likely

SECTION E: Expansion Timeline

[ASK E1 AND E2 IF S10 OR S11 OR S12 OR S13 OR S14 OR S15 OR S16= EXTREMELY LIKELY, VERY LIKELY, OR LIKELY]
E1. You indicated that you are likely to convert to natural gas. Assuming gas service is available after December 2015, when would you likely convert?
(READ LIST)

Within the first 12 months
Within 1 to 2 years
Within 2 to 3 years
After 3 years

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

E2. I am going to read you a list of appliances that could be powered by natural gas. For each appliance, please tell me if you would be extremely interested, very interested, interested, not very interested or not at all interested in natural gas for the appliance.

[READ; RANDOMIZE]
Fireplace
Oven, range or stove
Clothes dryer
BBQ
Other (**SPECIFY**)

[SCALE]
Extremely interested
Very interested
Interested
Not very interested
Not at all interested

FORUM
RESEARCH INC.

ASK QUESTIONS IN SECTION D IF SCR5 (2015) = RESIDENCE
SECTION D: Demographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

D1. Which of the following best describes the style of your house? Is it a …?

(READ LIST)
A bungalow or one story ranch
A raised ranch
A split level
A two story
Or a three story house
Some other style

D2. In order to have some idea as to the approximate size of your home in square feet (not including any unfinished basement) can you tell me how many square feet your home is?
[RECORD NUMBER. RANGE: 100 – 10000]

D3. In what year was your house built? Your best estimate is fine.
[RECORD YEAR]

ASK D3a IF COMMUNITY = PRINCE TOWNSHIP OR COMMUNITY = LAMBTON SHORES.
D3a. Which statement best describes the occupancy of this dwelling?

(READ LIST)
Occupied all-year round
Occupied mostly in the summer months
Occupied mostly in the winter months
Occupied occasionally year round

[SKIP TO D4 IF D3A = OCCUPIED ALL YEAR ROUND, ELSE CONTINUE]

D3b. For approximately how many months did you use this residence during 2014?

(RECORD NUMBER OF MONTHS)
[SCALE: 1-12]

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

D4. How many adults 18 years or over do you have living in your household, including yourself?

[RECORD NUMERIC RESPONSE. RANGE: 1 TO 20]

D5. And how many children 17 years or younger, if any, do you have living in your household?

[RECORD NUMERIC RESPONSE. RANGE: 0 TO 20]

D6. In what year were you born?

[RECORD YEAR. RANGE: 1900 TO 1993]

[ASK D6a IF REFUSE/DON'T KNOW AT D6, ELSE SKIP TO D7]

D6a. Can you please tell me into which of the following age groups you fall? Are you…?

(READ LIST UNTIL RESPONSE GIVEN)
18 to 24
25 to 34
35 to 44
45 to 54
55 to 64
65 or over

D7. And lastly, which of the following best describes your total household income before taxes? Please stop me when I reach your category. Is it…?

(READ LIST)
Under $20,000
$20,000 to less than $40,000
$40,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 to less than $120,000
$120,000 to less than $140,000
$140,000 or more

ASK QUESTIONS IN SECTION E IF SCR5 (2015) = BUSINESS
SECTION E: Firmographics

I just have a few additional questions for you that will help us group your answers with others who have also participated in the research. As a reminder, your answers will be kept completely confidential and they will not be tied back to you.

E1. How many buildings (are at this location?)
NOTE: IF LESS THAN ONE BUILDING, E.G. IF LOCATED IN A BUILDING OR SHOPPING PLAZA, ENTER "PART OF A BUILDING"
1,
2,
3,
OTHER (SPECIFY),
PART OF A BUILDING,
REFUSED
DON'T KNOW

E2. What is the approximate square footage of the indoor floor space (at this location of the first/second/third building), including basement and storage, but not including parking or loading areas?
Please consider only the area that is affected by a heating system.
[RECORD NUMBER]

E3. What is the age of the building at this location (of the first/second/third building)?

1 YEAR OR LESS,
2 TO 5 YEARS,
6 TO 10 YEARS,
11 TO 20 YEARS,
21 TO 30 YEARS,
31 TO 40 YEARS,
MORE THAN 40 YEARS OLD,
DON'T KNOW

DB3. How many floors does the building have?

(SPECIFY)

Thank you for your feedback. We appreciate your willingness to participate in this survey.

FORUM
RESEARCH INC.

Record of Contact

	Prince Township
Complete	**126**
Refusal	53
Callback	3
Answering machine	15
Vacation	1
Terminate partway	2
Language	4
Not in	11
Wrong number	11
Duplicate	2
Dialer - No answer	28
Dialer - Busy	2
Dialer - Operator intercept	45
Dialer - Dropped call	4
Dialer - Answering machine	52
Dialer - Fax/modem	2
Disqualified	2
Other	5
TOTAL	**368**

180 Bloor Street W., Suite 1400, Toronto, ON M5S 2V6 T 416.960.9600 F 416.960.9602 forumresearch.com

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section A, p. 5

Due to the low response rate of the 2014 survey, Union has used its experience of attachment rates with past projects and taken a conservative approach to develop the attachments forecasts for the Ipperwash Beach area. Union has used an 82% attachment rate for residential customers and 100% attachment rate for commercial customers.

a) Please provide results from past projects that Union has referred to and compare the demographics with the results of the Ipperwash Beach area survey.

b) Union has used an 82% attachment rate for residential and 100% for commercial customers. Does this imply that 82% of residential customers and 100% of commercial customers who answered extremely likely, very likely and 50% of those who answered likely will attach to natural gas service in the first 10 years of the project?

c) Please explain how Union is confident of its projections considering that the forecasts are based on a 2011 survey that did not make any reference to Union's current proposal.

d) Did the 2011 survey inform respondents about the cost of conversion and then gauged their interest in converting to natural gas?

Response:

a) Please see Attachment 1 which provides a history of attachments for community expansion projects.

b) Union used an 82% attachment rate for residential and 100% attachment rate for commercial customers that would be located within the Kettle Point area of the Project. The attachment rate for the Kettle Point and Stony Point First Nations area of the Project is based on historic attachment rates for past First Nations communities.

c) Union completed a survey[1] that factors in the need for a TES and the results indicate that the forecasted attachment rate should be 63%. Based on this more recent data, the 47% in Exhibit A, Tab 2 is conservative.

d) Confirmed.

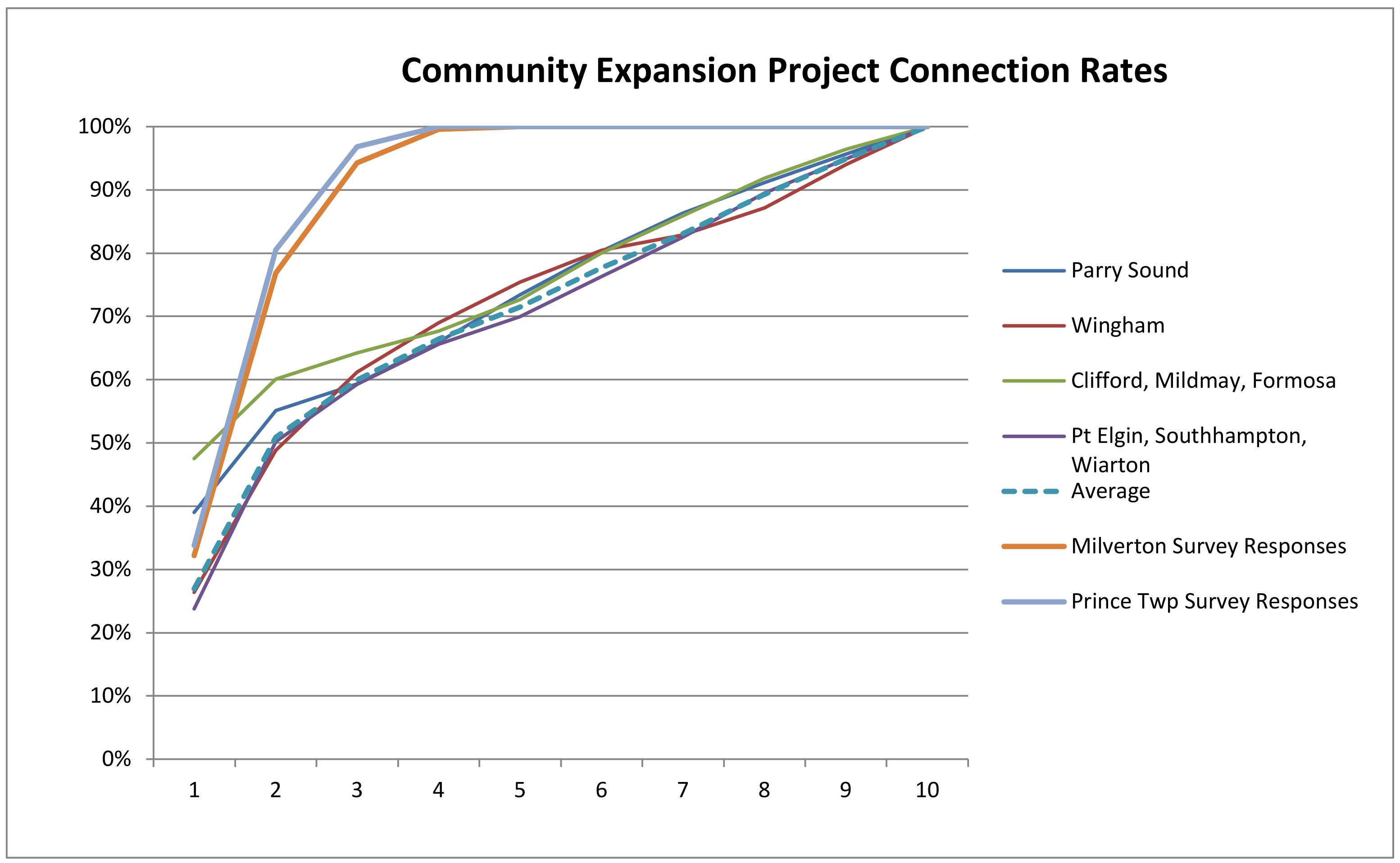
[1] Exhibit B.Staff.11, Attachment 1, p. 8 including extremely likely, very likely, and 50% of likely responses.

Community Expansion Project Connection Rates

Year	Actual Connections: Parry Sound	Actual Connections: Wingham	Actual Connections: Clifford, Mildmay, Formaosa	Actual Connections: Pt Elgin, Southhampton, Wiarton	Actual Connections: Total	Connection Rates: Parry Sound	Connection Rates: Wingham	Connection Rates: Clifford, Mildmay, Formosa	Connection Rates: Pt Elgin, Southhampton, Wiarton	Connection Rates: Average	Connection Rates: Milverton Survey Responses	Connection Rates: Prince Twp Survey Responses	Cumulative Connections: Parry Sound	Cumulative Connections: Wingham	Cumulative Connections: Clifford, Mildmay, Formosa	Cumulative Connections: Pt Elgin, Southhampton, Wiarton	Cumulative Connections: Average	Cumulative Connections: Milverton Survey Responses	Cumulative Connections: Prince Twp Survey Responses
1	305	476	250	1,430	2,461	39%	26%	48%	24%	27%	32%	34%	39%	26%	48%	24%	27%	32%	34%
2	126	406	66	1,588	2,186	16%	22%	13%	26%	24%	45%	47%	55%	49%	60%	50%	51%	77%	81%
3	33	223	22	547	825	4%	12%	4%	9%	9%	17%	16%	59%	61%	64%	59%	60%	94%	97%
4	52	140	18	380	590	7%	8%	3%	6%	6%	5%	3%	66%	69%	68%	66%	66%	100%	100%
5	58	116	26	261	461	7%	6%	5%	4%	5%	0%		73%	75%	73%	70%	71%	100%	100%
6	54	91	39	384	568	7%	5%	7%	6%	6%			80%	80%	80%	76%	78%	100%	100%
7	47	44	31	371	493	6%	2%	6%	6%	5%			86%	83%	86%	83%	83%	100%	100%
8	38	77	31	422	568	5%	4%	6%	7%	6%			91%	87%	92%	90%	89%	100%	100%
9	35	124	24	323	506	4%	7%	5%	5%	6%			96%	94%	96%	95%	95%	100%	100%
10	34	108	19	307	468	4%	6%	4%	5%	5%			100%	100%	100%	100%	100%	100%	100%
	782	**1,805**	**526**	**6,013**	**9,126**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**							

	Parry Sound	Wingham	Clifford, Mildmay, Formaosa	Pt Elgin, Southhampton, Wiarton	Total
Max Potential Custon	**2,610**	**3,445**	**1,049**	**9,391**	**16,495**
10 Yr Forecast	**1,890**	**3,032**	**816**	**8,487**	**14,225**
Aid Mechanism	MC	MCC	MC	MC	
Amount	$600.00	$15.00	$373.00	$377.76	

MCC: Market Contribution Charge- A monthly fixed charge (applied for 5 years for Wingham)
MC: Market Charge- A single up front payment from every customer at time of connection



UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section A, Schedule 11, p. 6

Union has indicated that it informed the Chippewas of Kettle and Stony Point First Nation of their community expansion proposal and provided them with information regarding the benefits of natural gas and the approximate costs of converting to natural gas during spring 2014. Union has noted that telephone surveys will be conducted in Lambton Shores to determine the level of interest in receiving natural gas service and to inform them of Union's proposal.

a) How did Union inform the Chippewas of Kettle and Stony Point First Nation of their proposal?

b) When does Union plan to complete the telephone survey in Lambton Shores and will the results be filed with the OEB?

Response:

a) Union consulted with the Chief, General Manager and Band Council of the Chippewas of Kettle and Stony Point First Nations. For a detailed list of the contacts please see Exhibit A, Tab 2, Section A, pp. 11-12.

b) Union completed the telephone survey in Lambton Shores. Please see the response at Exhibit B.Staff.11, Attachment 1.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section B, p. 4, para. 18-22

Union completed a telephone survey for the Milverton area and based on the results it has forecasted a total of 375 existing residential, 100 new residential, 45 existing medium and small commercial, 5 existing large commercial and one existing seasonal customers to be attached by the tenth year of the project.

Based on experience of attachment rates with past projects, Union has taken a conservative approach and reduced the attachment forecast from 74% (respondents extremely likely, very likely and likely to convert) to 59% (extremely likely, very likely, 50% of likely) for the existing residential, small commercial and medium commercial customers.

a) What is Union's forecast for the 100 new residential customers and what is the basis for the forecast?

b) Union has based its forecast for existing customer conversions on experience with past projects. Please provide details of the past projects that Union is referring to and the forecast and actual attachments.

c) Did Union conduct a similar survey for the Red Lake Project? If yes, please provide the forecast attachments, the basis of the forecast and the actual attachments to-date.

Response:

a) Union based its forecast of 100 new residential customers on the discussions with Municipal officials in Milverton and draft plan subdivisions which have been submitted to the Municipality.

b) Please see the response at Exhibit B.Staff.12, Attachment 1.

c) Yes. Union did conduct a similar survey for the Red Lake Project. In the EB-2011-0040 proceeding, Union identified that there were 1,265 private dwellings in the Municipality of Red Lake. Please see Attachment 1 for the attachment forecast and actual attachments to date.

Red Lake - Current Customer Attachments (Services) vs Original Forecast
Nov 20, 2015 vs Feb 8, 2011 Phase II Submission

	2012 Year 1			**2013 Year 2**			**2014 Year 3**			**2015 Year 4**			**2016 Year 5**	**2017 Year 6**	**2018 Year 7**	**2019 Year 8**	**2020 Year 9**	**2021 Year 10**	**2012-2021 TOTAL**	
	Original Forecast	Actual Attachmts	**% of Actual vs forecast**	Original Forecast	Actual Attachmts	**% of Actual vs forecast**	Original Forecast	Actual Attachmts	**% of Actual vs forecast**	Original Forecast	Actual Attachmts	**% of Actual vs forecast**	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Original Forecast	Actual Attachments (2012-2015)
Conversion Residential	359	332	**92%**	225	272	**121**	162	188	**116**	85	127	**149**	60	55	45	30	25	25	1071	919
New Construction Res	33	1	**3%**	26	3	**12**	17	3	**18**	17	1	**6**	17	8	8	8	8	8	150	8
TOTAL	392	333	**85%**	251	275	**110**	179	191	**107**	102	128	**125**	77	63	53	38	33	33	1221	927
Commercial R-01	68	36	**53%**	44	28	**64**	30	13	**43**	16	9	**56**	12	7	4	4	3	3	191	86
New Construction R-01 comm	3	0	**0%**	3	2	**67**	2	2	**100**	2	0	**0**	2	1	1	1	0	0	15	4
TOTAL	71	36	**51%**	47	30	**64**	32	15	**47**	18	9	**50**	14	8	5	5	3	3	206	90
OVERALL TOTAL	463	369	**80%**	298	305	**102**	211	206	**98**	120	137	**114**	91	71	58	43	36	36	1427	1017

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 3, p. 1, lines 1-4

Union is proposing a volumetric based Temporary Connection Surcharge (TCS) for projects that do not meet the definition of a Community Expansion Project and do not qualify for reduced economic feasibility thresholds. Union is proposing a volumetric based TCS that is similar to the TES.

a) What kind of projects would not meet the definition of a Community Expansion Project but would still provide service to a rural or remote community?

b) Does Union propose to levy the TES and ITE surcharges for the non-community expansion projects?

Response:

a) The projects referenced are smaller main extension projects that will provide service to fewer than 50 existing homes or businesses, or abnormally long commercial service requests. The most common examples of one of these projects would be:

- A few hundred meters of main extension to serve an individual residential or commercial customer;
- The extension of a short (i.e. ½ kilometre) plastic distribution main to service three or four customers; and,
- A commercial customer with an abnormally long service line.

The TCS would also be available for commercial or industrial general service attachment requests that would require an abnormally long service line from the main.

These types of requests are more common where a farm or rural customer is closer to Union's existing distribution system. Union routinely services these requests currently, applying E.B.O. 188 guidelines. The TCS proposal is a tool for customers to provide additional revenue over time where an economic shortfall exists, as opposed to being required to pay significant levels of up-front Aid-to-Construction.

b) No, the TES and ITE would not apply to these projects as they are not within the scope of the proposals for projects defined as Community Expansion Projects. These smaller projects are considered part of Union's routine new business capital expenditures. These projects are each generally required to meet a minimum P.I. of 1.0. For these reasons Union has not proposed pass-through treatment of capital costs for these projects, or deferral accounts to credit existing ratepayers for TCS funds collected.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section A, p. 10, para 48
Exhibit A, Tab 2, Section B, p. 10, para 54
Exhibit A, Tab 2, Section C, p. 9, para 43
Exhibit A, Tab 2, Section D, p. 8, para 44
Exhibit A, Tab 2, Section E, p. 10, para 51

Union has submitted copies of the Environmental Protection Plan (EPP) to the Ontario Pipeline Coordinating Committee, local municipalities, and First Nations and Metis.

Please file an updated summary of comments and concerns received to date and Union's responses and planned actions to mitigate each of the issues and address each of the concerns.

Response:

Please see Attachments 1, 2, 3 and 4 for the updated Ontario Pipeline Coordinating Committee ("OPCC") comments.

OPCC Review Summary

Kettle Point/Lambton Shores Natural Gas Pipeline Project

AGENCY	COMMENT	RESPONSE
Technical Standards and Safety Authority Email dated June 22, 2015	The design and piping specifications project meet the requirements of O. Reg. 210/01. I'm passing the documentation submitted to Mike Davis, our regional manager for his knowledge and/or actions that may be required.	Not Required.
Technical Standards and Safety Authority Email dated June 22, 2015	Please include Inspector Curtis Poulin and Lead Inspector and Investigator Inspector Ralph Schubert in all communication for this site.	Not Required.
St. Clair Region Conservation Authority (SCRCA) Email dated August 5, 2015	SCRCA does not regulate the lands on Kettle Point First Nation. The lands outside of Kettle Point First Nation are all within areas affected by SCRCA regulations. Provided a list of fees for EA services offered by SCRCA (data collection, environmental studies, etc.). Provided a link to the Thames-Sydenham Source Protection Region Assessment Reports.	Not Required.
Ministry of Tourism, Culture & Sport (MTCS) Email and letter dated August 6, 2015	Email containing a letter to Zora Crnojacki: Provide MTCS with any archaeological assessment and/or cultural heritage assessment reports and/or technical heritage study prior to issuance of a Notice of Completion. Engagement with Aboriginal communities should include a discussion about known or potential cultural heritage resources and other local heritage organization should be consulted as required. Avoid assuming there will be no	Email containing a letter dated November 23, 2015: Engagement with the Chippewas of Kettle and Stony Point First Nation has been ongoing from the onset of the Stage 1 Archaeological Assessment and cultural heritage study. Archaeological monitors from Chippewas of Kettle and Stony Point First Nation, Delaware Nation at Moraviantown, and Walpole Island First Nation were involved in Stage 2 surveys. No sites have been discovered and the Stage 1 and 2

	impacts to archaeological resources; recommend including the weighting of actual or potential impacts in the evaluation of alternatives. The MTCS Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes should be completed and included in the EA report or file. A Heritage Impact Assessment is recommended if potential or known heritage resources exist. MTCS requests continued circulation through the EA process.	Archaeological Assessment Report is being finalized for submission to the MTCS. An *Overview of Heritage Resources* report is being finalized and the MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed.

Tomek, Evan

From:	Oscar Alonso <oalonso@tssa.org>
Sent:	June-22-15 4:05 PM
To:	Park, Ryan
Cc:	Mike Davis
Subject:	Kettle Point/Lambton Shores Natural Gas Pipeline Project

Thanks Ryan for the information. The design and piping specifications project meet the requirements of O. Reg. 210/01.

I'm passing the documentation submitted to Mike Davis, our regional manager for his knowledge and/or actions that may be required.

Regards,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

Tomek, Evan

From: Mike Davis <mdavis@tssa.org>
Sent: June-22-15 5:07 PM
To: Park, Ryan
Cc: Oscar Alonso; Curtis Poulin; Ralph Schubert
Subject: Re: Kettle Point/Lambton Shores Natural Gas Pipeline Project

Greetings please include. Inspector. Curtis. Poulin. Lead. Inspector and Investigator Inspector. Ralph. Schubert in all communication for this site. Thanks to all. Mike. Davis

Sent From: iPhone

On Jun 22, 2015, at 16:09, Park, Ryan <RDPark@uniongas.com> wrote:

Oscar,

Thank you very much; I look forward to any comments or requirement Mike may have.

Regards,

Ryan Park, B.Sc., Can-CISEC
Senior Environmental Planner, Permitting & Environmental Planning
Union Gas Limited | A Spectra Energy Company
Ph: 519 436-2460 x5233007
Cell: 519 350-0289

From: Oscar Alonso [mailto:oalonso@tssa.org]
Sent: June-22-15 4:05 PM
To: Park, Ryan
Cc: Mike Davis
Subject: Kettle Point/Lambton Shores Natural Gas Pipeline Project

Thanks Ryan for the information. The design and piping specifications project meet the requirements of O. Reg. 210/01.

I'm passing the documentation submitted to Mike Davis, our regional manager for his knowledge and/or actions that may be required.

Regards,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

This communication from the Technical Standards and Safety Authority may contain information
that is privileged, confidential or otherwise protected from disclosure and it must not be disclosed,
copied, forwarded or distributed without authorization. If you have received this message in error,
please notify the sender immediately and delete the original message.

This electronic message and any attached documents are intended only for the named recipients. This communication from the Technical Standards and Safety Authority may contain information that is privileged, confidential or otherwise protected from disclosure and it must not be disclosed, copied, forwarded or distributed without authorization. If you have received this message in error, please notify the sender immediately and delete the original message.

Tomek, Evan

From:	Sarah Hodgkiss <shodgkiss@scrca.on.ca>
Sent:	August-05-15 3:11 PM
To:	Park, Ryan
Subject:	Kettle Point/Lambton Shores Natural Gas Pipeline Project

Hi Ryan,

The St. Clair Region Conservation Authority (SCRCA) acknowledges receipt of your letter regarding the proposed Kettle Point/Lambton Shores Natural Gas Pipeline Project. Please note that SCRCA does not regulate the lands on Kettle Point First Nation. However, the land of the proposed distribution station, and proposed NPS 6 and NPS 4 are all within areas affected by SCRCA regulations.

Please see below the list of fees for EA service as approved by our Board of Directors.

PLANNING SERVICE FEES		
Technical Report Review and Background Data Collection/Provision		
Data Requests (plus tax)		
Minimum Base (includes up to 3 data sets) plus $100.00 per data set***		
Report Review and Background Data Collection (non Environmental Assessment Act) Minor (scoped)		**Natural Hazard**
	Scoped impact study and proposed mitigation measures– (ie. internal review of : floodline, coastal , hydrogeology, geotechnical, meander belt, wetland (scoped EIS/DAR))	$300.00
Major		
	Comprehensive impact study and proposed mitigation measures - (ie. floodline, coastal , geotechnical, hydrogeology, geotech, meander belt, full EIS/DAR)	$500
	Report review - external review	BOQ² ie. Coastal or Geotech $2,000.00 - 8,000.00
**Authority staff reserve the right to charge technical report review fees over the above noted fees for complex projects having potential significant impact. Costs will be related to multiple technical report reviews, multiple meetings, etc Director and GM to approve fee.		
***data sets - regulation limit mapping, ESA mapping & info, wetland mapping & info, benthic sampling data, water quality data, fish sampling data		
¹includes applicable adjacent lands		
²BOQ - based on quote		

The Thames-Sydenham Source Protection Region has recently prepared Assessment Reports designed to identify and help address drinking water source protection concerns. The reports and relevant maps are available at: http://www.sourcewaterprotection.on.ca. Source Protection policies have been developed with the intent to reduce risks posed by identified water quality and quantity threats in these vulnerable areas. These draft policies are also available on the website.

If you wish to proceed and obtain any of the above listed information, please forward the required fee along with your request.

Sarah

Sarah Hodgkiss

St. Clair Region Conservation Authority
Planning Ecologist

(519) 245-3710 ext. 234
shodgkiss@scrca.on.ca

205 Mill Pond Cresc.
Strathroy ON N7G 3P9

Ministry of Tourism, Culture and Sport

Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto ON M7A 0A7
Tel: 416 314 7145
Fax: 416 212 1802

Ministère du Tourisme, de la Culture et du Sport

Unité des services culturels
Direction des programmes et des services
401, rue Bay, Bureau 1700
Toronto ON M7A 0A7
Tél: 416 314 7145
Téléc: 416 212 1802

Ontario

August 6, 2015 (EMAIL ONLY)

Zora Crnojacki, Coordinator
Ontario Pipeline Coordination Committee
Ontario Energy Board
Suite 2601, 2300 Yonge Street
Toronto, ON M4P 1E4
E: zora.crnojacki@ontarioenergyboard.ca

RE:	**MTCS file #:**	**0002990**
	Proponent:	**Union Gas**
	Subject:	**Environmental Protection Plan** **Kettle Point / Lambton Shores Natural Gas Pipeline Project**
	Location:	**Municipality of Lambton Shores, County of Lambton, Ontario**

Dear Zora Crnojacki:

The Ministry of Tourism, Culture and Sport (MTCS) is in receipt of the Environmental Protection Plan for the above project. MTCS's interest in this EA project relates to its mandate of conserving Ontario's cultural heritage, which includes:

- Archaeological resources, including land-based and marine;
- Built heritage resources, including bridges and monuments; and,
- Cultural heritage landscapes.

Under the ER process for Ontario Energy Board projects, the proponent is required to determine a project's potential impact on cultural heritage resources. MTCS should be provided with any archaeological assessment and/or cultural heritage assessment reports completed for the above project prior to issuance of a Notice of Completion.

While some cultural heritage resources may have already been formally identified, others may be identified through screening and evaluation. Aboriginal communities may have knowledge that can contribute to the identification of cultural heritage resources, and we suggest that any engagement with Aboriginal communities includes a discussion about known or potential cultural heritage resources that are of value to these communities. Municipal Heritage Committees, historical societies and other local heritage organizations may also have knowledge that contributes to the identification of cultural heritage resources.

Archaeological Resources
It is understood from the Environmental Protection Plan that a Stage 1 archaeological assessment (AA) shall be undertaken by an archaeologist licenced under the *OHA*, who is responsible for submitting the report directly to MTCS for review. While construction is described as remaining entirely within the disturbed portion of the road allowance, we note that many of these corridors comprise original concession and early EuroCanadian settlement roads, built prior to archaeological assessments, and so may intersect as yet unregistered archaeological sites. The scope of soil disturbance related to the project also includes proposed regulating stations and may involve temporary staging and stockpiling areas and access routes which may be relatively undisturbed. As a result, we advise against presuming that there will be no impacts to archaeological resources and instead recommend including the weighting of actual or potential impacts in the evaluation of alternatives.

Built Heritage and Cultural Heritage Landscapes
The Environmental Protection Plan confirms that the study area will be screened for potential built heritage and cultural heritage landscapes. The MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* should be completed to help determine potential impacts to impact cultural heritage resources. The Clerks for the Municipality of Lambton Shores and County of Lambton can provide information on property registered or designated under the *Ontario Heritage Act*. Municipal Heritage Planners can also provide information to complete the checklist.

If potential or known heritage resources exist, MTCS recommends that a Heritage Impact Assessment (HIA), prepared by a qualified consultant, should be completed to assess potential project impacts. Our Ministry's *Info Sheet #5: Heritage Impact Assessments and Conservation Plans* outlines the scope of HIAs. Any HIA completed is to be sent to MTCS for review, and made available to local organizations or individuals who have expressed interest in heritage.

Environmental Assessment Reporting
All technical heritage studies and their recommendations are to be addressed and incorporated into EA projects. Technical heritage studies completed for the EA project are to be provided to MTCS before a Notice of Completion is issued. If screening has identified no known or potential cultural heritage resources, or no impacts to these resources, the completed checklists and supporting documentation should be included in the EA report or file.

MTCS requests continued circulation through the EA process: I may be contacted for any questions or clarification.

Sincerely,

Joseph Muller, RPP/MCIP
Heritage Planner
Joseph.Muller@Ontario.ca

Copied to: Ryan Park, Senior Environmental Planner, Union Gas

It is the sole responsibility of proponents to ensure that any information and documentation submitted as part of their EA report or file is accurate. MTCS makes no representation or warranty as to the completeness, accuracy or quality of the any checklists, reports or supporting documentation submitted as part of the EA process, and in no way shall MTCS be liable for any harm, damages, costs, expenses, losses, claims or actions that may result if any checklists, reports or supporting documents are discovered to be inaccurate, incomplete, misleading or fraudulent.

MTCS must be notified if archaeological resources are impacted by EA project work. All activities impacting archaeological resources must cease immediately, and a licensed archaeologist is required to carry out an archaeological assessment in accordance with the Ontario Heritage Act and the Standards and Guidelines for Consultant Archaeologists.

If human remains are encountered, all activities must cease immediately and the local police as well as the Cemeteries Regulation Unit of the Ministry of Government and Consumer Services must be contacted. In situations where human remains are associated with archaeological resources, MTCS should also be notified to ensure that the site is not subject to unlicensed alterations which would be a contravention of the Ontario Heritage Act.

Tomek, Evan

From:	Tomek, Evan
Sent:	November-23-15 12:42 PM
To:	'Joseph.Muller@Ontario.ca'
Subject:	Community Expansion Program Update
Attachments:	MTCS Moraviantown Update.pdf; MTCS Walpole Update.pdf; MTCS Milverton Update.pdf; MTCS KP LS Update.pdf

Good Afternoon Joseph,

Thank you for your reviews of Union Gas' Environmental Protection Plans for our Moraviantown, Walpole Island, Milverton, and Kettle Point / Lambton Shores Natural Gas Pipeline Projects.
I have attached four letters providing an update regarding our Archaeology and Cultural Heritage works for each project.
I appreciate your time with these reviews, and if you have any questions don't hesitate to ask.

Thanks,

Evan

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: etomek@uniongas.com

Canada's Top 100 Employers 2015

uniongas
A Spectra Energy Company

November 23, 2015 (VIA EMAIL)

Joseph Muller, Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto, ON M7A 0A7
Email: Joseph.Muller@Ontario.ca

RE: Kettle Point / Lambton Shores Natural Gas Pipeline Project

Dear Mr. Muller,

Thank you for your review of the report entitled, *Kettle Point / Lambton Shores Natural Gas Pipeline Project Environmental Protection Plan, May 2015,* and subsequent letter dated August 6, 2015. We appreciate you taking the time to review the report and provide important feedback.

Union Gas Limited (Union) retained the services of D.R. Poulton & Associates to complete a Stage 1 and 2 Archaeological Assessment of the proposed pipeline project area to identify potential impacts to archaeological resources. D.R. Poulton & Associates requested archaeological information from the Chippewas of Kettle and Stony Point First Nation (CKSPFN) during June 2015 and an opportunity to meet and tour the proposed pipeline route on June 26, 2015. Members of CKSPFN declined this opportunity however; archaeological monitors from CKSPFN, Delaware Nation at Moraviantown, and Walpole Island First Nation were present for a Stage 2 archaeological survey on October 26, 2015. Currently, the Stage 2 archaeological survey of the proposed pipeline route has been completed with no sites discovered. The Stage 1 and 2 Archaeological Assessment report is being finalized for submission to the Ministry.

Union retained the services of Stantec Consulting Ltd. (Stantec) to identify potential built heritage and cultural heritage landscapes in the project area. Stantec consulted the Ontario Heritage Trust, and worked with CKSPFN to identify such features and found no concerns. Stantec had also previously consulted the Municipality of Lambton Shores and confirmed that no protected resources are situated within the vicinity of the proposed pipeline. Currently, the *Overview of Heritage Resources* report is being finalized for submission to the Ministry and the Ministry's *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed.

Thank you again for your time and we will notify you of the submission of the aforementioned reports. If you have any questions do not hesitate to ask.

Yours Truly,

Evan Tomek
Environmental Planner
Union Gas Limited
Tel: 519.436.2460 ext 5236904
Email: etomek@uniongas.com

OPCC Review Summary

Milverton Natural Gas Pipeline Project

AGENCY	COMMENT	RESPONSE
Technical Standards and Safety Authority Email dated July 2, 2015	The design and piping specifications project meet the requirements of O. Reg. 210/01. However, if the project is constructed in the spring of 2016, the new Code Adoption Document (CAD) enforcing the CSA Z662-15 may be in effect at that time. Forwarding the EPP to Mike Davis, our regional manager for his knowledge and/or actions that may be required.	Not Required.
Upper Thames River Conservation Authority Email and letter dated July 9, 2015	Email containing a letter with comments: UTRCA Regulated Areas 1. Portions of the study area occur within areas regulated by the UTRCA. We note our mapping indicated two additional watercourses within the UTRCA portion of the study area that do not appear to be denoted on the screening report plans: one watercourse crossing the proposed pipeline route at Line 42 and one crossing at Line 52. Water Quality, Woodlands and Other Natural Heritage Features 2. Please refer to the latest (2012) edition of the Upper Thames River Watershed Report Cards for natural heritage information related to the Whirl Creek and Black Creek subwatersheds. Summary We have not received enough information to provide detailed comments regarding the project. However, we appreciate being	Email dated July 9, 2015: Thank you very much for you response and input on our Milverton Pipeline Project. I will work towards adding the two additional crossings our future plan drawings. We will be contacting UTRCA for pre-consultation in support of our future permit application under O. Reg. 157/06. Thank very much for your time spent reviewing and commenting on our report.

	contacted early in the process, are available to meet, and would like to be included in future circulations regarding the project to be able to provide timely comments.	
Township of Perth East Email dated July 10, 2015	Requested an electronic version of the EPP to circulate internally for comments.	Forwarded an electronic copy of the EPP on July 10, 2015.
Township of Perth East Email and letter dated July 23, 2015	Email containing a letter with comments: The comprehensive report generally addresses the necessary aspects of an undertaking such as this and the Township is confident that it deals with environmental issues appropriately. 1. The Gies subdivision is only in its draft stages – when/where is the 4" main planned to be installed in this area? If the main is required as part of the initial installation, the 4 inch could be installed along Mill Street East. If the main is to be installed in the future, consideration should be given to having it installed in co-ordination with the development and installation of services of the subdivision, wherever that occurs. 2. If there is potential for disruption of any natural features, the County's Planning and Development Department shall be contacted. 3. Respective CA's should be consulted on the project. 4. Any required disruption of trees shall be in compliance with the "County of Perth By-law Number 2927 – Being a By-Law to prohibit or regulate the destruction or injuring of trees, in woodlands and woodlots in the County of Perth". Questions on this issue should be referred to the County's Planning and Development Department.	Sent an email containing a response letter on September 28, 2015: 1. Union Gas is planning on installing the 4" PE pipeline within the subdivision as it is constructed. This section of pipeline is not required when Union Gas installs the initial distribution system in Milverton. Union Gas will work with the Township and the developer to determine the location and timing of installation of the pipeline within the subdivision. 2. All required environmental permits and approvals will be obtained prior to the initiation of works, including those issued by the County of Perth. The County's Planning and Development Department shall be consulted for permitting requirements if there is the potential for disruption of the natural feature identified in Section 3.2 of the Environmental Screening Report. 3. Respective CA's (Maitland Valley Conservation Authority, Grand River Conservation Authority and Upper Thames River Conservation Authority) have received copies of the Environmental Protection Plan and Environmental Screening Report. All required permits and approvals for the respective CA's will be obtained prior to the initiation of works within regulated

	5. *Comments 5-8 discuss roadways/ road allowances owned by the Township vs. the municipality vs. landowners and construction therein. Contact Glenn Schwendinger, CAO at gschwendinger@pertheast.ca or 519-595-2800 ext. 232 for more information.	lands. 4. Any required disruption of trees will be completed in consultation with and the approval of the County's Planning and Development Department. 5. Union will be conducting detailed surveys of the areas identified by the municipality in the near future to determine the exact location of the road allowance. After these studies have been completed Union will work with the municipality and adjacent landowners to determine the location of the proposed pipeline. 6. See Response #5. 7. See Response #5. 8. See Response #5.
Grand River Conservation Authority Letter dated July 27, 2015	A very small portion of the project is located within the GRCA watershed. A permit will be required for crossing the tributary of Smith Creek along Mill St. East (HDD method or otherwise). Other watercourse crossings or culvert installations in the GRCA watershed may require a permit. Attached a copy of the GRCA mapping for the portion of Milverton that is within the Watershed. Please advise when you are ready to proceed with the permit application for assistance.	Not Required.
Ministry of Tourism, Culture & Sport (MTCS) Email and letter dated August 6, 2015	Email containing a letter to Zora Crnojacki: Provide MTCS with any archaeological assessment and/or cultural heritage assessment reports and/or technical heritage study prior to issuance of a Notice of Completion. Engagement with Aboriginal communities should include a discussion about known or potential cultural heritage	Email containing a letter dated November 23, 2015: A Stage 1 Archaeological Assessment Report was submitted to the MTCS on November 17, 2015. A Stage 2 Archaeological Assessment will be conducted on portions of the proposed pipeline route. An *Overview of Heritage*

	resources and other local heritage organization should be consulted as required. Avoid assuming there will be no impacts to archaeological resources; recommend including the weighting of actual or potential impacts in the evaluation of alternatives. The MTCS Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes should be completed and included in the EA report or file. A Heritage Impact Assessment is recommended if potential or known heritage resources exist. MTCS requests continued circulation through the EA process.	*Resources* report is being finalized for submission to the MTCS and the MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed. The MTCS, Ontario Heritage Trust, and the Township of Perth East were consulted during the cultural heritage study.
Ministry of Natural Resources and Forestry Email dated September 3, 2015	Provided comments regarding Species at Risk (SAR): • If trees might be removed or damaged they should be identified to determine if they are listed under the *Endangered Species Act* (ESA). • If Butternut may be impacted, please refer to Section 23.7 of the ESA to determine whether the project may qualify for registration. • For any tree proposed for removal, it is recommended that a qualified individual assess the suitability of the tree for potential habitat/roosting habitat of endangered bats. • Prior to construction of the project, the project team may wish to apply for a Wildlife Scientific Collectors authorization under the *Fish and Wildlife Conservation Act* If Snapping Turtles are found nesting in the project area, the MNRF can be contacted for further direction.	Not Required.

	• If the project has the potential to impact Bobolink or Eastern Meadowlark habitat during the breeding bird season, the MNRF recommends that the project team refer to the exemption regulation under Section 23.6 of Ontario Regulation 242/08 to determine whether the project may qualify for registration.	

Tomek, Evan

From: Oscar Alonso <oalonso@tssa.org>
Sent: July-02-15 11:53 AM
To: Park, Ryan
Cc: Kourosh Manouchehri; Mike Davis; Zora Crnojacki
Subject: Union Gas Limited Community Expansion Program. Milverton Natural Gas Pipeline Project

Thanks Ryan for the information on the referenced project, dated May 2015. The design and piping specifications project meet the requirements of O. Reg. 210/01. However, if the project is constructed in the spring of 2016, the new Code Adoption Document (CAD) enforcing the CSA Z662-15 may be in effect at that time.

I'm passing the documentation submitted to Mike Davis, our regional manager for his knowledge and/or actions that may be required.

Regards,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

Tomek, Evan

From:	Park, Ryan
Sent:	July-09-15 4:20 PM
To:	'Karen Winfield'
Subject:	RE: Union Gas - Milverton Pipeline Project, Perth East

Hi Karen,

Thank you very much for you response and input on our Milverton Pipeline Project. I will work towards adding the two additional crossings our future plan drawings. We will be contacting UTRCA for pre-consultation in support of our future permit application under O.Reg. 157/06.

Thank very much for your time spent reviewing and commenting on our report.

Cheers,

Ryan Park, B.Sc., Can-CISEC
Senior Environmental Planner, Permitting & Environmental Planning
Union Gas Limited | A Spectra Energy Company
Ph: 519 436-2460 x5233007
Cell: 519 350-0289

From: Karen Winfield [mailto:winfieldk@thamesriver.on.ca]
Sent: July-09-15 3:52 PM
To: Park, Ryan
Subject: Union Gas - Milverton Pipeline Project, Perth East

Hi Ryan,

Please see attached UTRCA comments regarding the Union Gas Limited Community Expansion Program - Milverton Natural Gas Pipeline Project in the Township of Perth East.

Thank-you,

Karen Winfield
Land Use Regulations Officer
1424 Clarke Road London, Ontario, N5V 5B9
519.451.2800 Ext. 237 | Fax: 519.451.1188
winfieldk@thamesriver.on.ca

UPPER THAMES RIVER
CONSERVATION AUTHORITY

UPPER THAMES RIVER
CONSERVATION AUTHORITY

"Inspiring a Healthy Environment"

The Thames
A Canadian
Heritage River

July 9, 2015

Union Gas Limited
750 Richmond Street
Chatham, Ontario
N7M 5J5

Attention: **Ryan Park** – (via e-mail: rdpark@uniongas.com)

Dear Mr. Park:

Re: **Union Gas Limited Community Expansion Program**
Milverton Natural Gas Pipeline Project
Environmental Protection Plan
County of Perth, Township of Perth East (Ellice)

Upper Thames River Conservation Authority (UTRCA) staff are in receipt of the Environmental Protection Plan and associated letter regarding the Union Gas Limited Community Expansion Program: Milverton Natural Gas Pipeline Project in the Township of Perth East. We offer the following comments under Ontario Regulation 157/06 and our responsibilities as a commenting agency providing technical review and advisement related to natural heritage, water resources and natural hazard management pursuant to relevant legislation and policies set out in the UTRCA Planning Policy Manual (June 28, 2006):

UTRCA Regulated Areas

1) According to the enclosed project location mapping, portions of the study area occur within natural hazard and natural heritage areas regulated by the Conservation Authority. The UTRCA regulates development within the Regulation Limit in accordance with Ontario Regulation 157/06 made pursuant to Section 28 of the *Conservation Authorities Act*. This regulation requires proponents to obtain written approval from the UTRCA prior to undertaking any works in the regulated area including filling, grading, construction, alteration to a watercourse and/or interference with a wetland.

   We note our mapping indicates two additional watercourses within the UTRCA portion of the study area that do not appear to be denoted on the screening report plans: one watercourse crossing the proposed pipeline route at Line 42 and one crossing at Line 52.

Water Quality, Woodlands and Other Natural Heritage Features

2) The study area lies within a portion of the Whirl Creek and Black Creek subwatersheds. Please refer to our latest (2012) edition of the Upper Thames River Watershed Report Cards for information

related to water quality, woodlands and other natural heritage features in these subwatersheds, available on our website at:

http://thamesriver.on.ca/watershed-health/watershed-report-cards/

Summary

Please be advised that we have not yet received enough information to provide detailed comments regarding the project. However, we appreciate being contacted early in the process and are always open to meeting with you to discuss and work through any concerns or complications along the way.

Our office would like to be included in future circulations regarding this project. We would appreciate receiving information and reports as they become available in order to ensure that we can meet the project deadlines with our comments.

If you have any questions regarding the above information, please contact the undersigned.

Yours truly,
UPPER THAMES RIVER CONSERVATION AUTHORITY

Karen M. Winfield

Karen M. Winfield
Land Use Regulations Officer

1424 Clarke Road, London, Ont. N5V 5B9 · Phone: 519.451.2800 · Fax: 519.451.1188 · Email: infoline@thamesriver.on.ca · www.thamesriver.on.ca

Tomek, Evan

From: Glenn Schwendinger <gschwendinger@pertheast.ca>
Sent: July-10-15 1:39 PM
To: Park, Ryan
Subject: Re: Milverton Natural Gas Pipeline Project EPP

Yes I did. Thanks.

From: Park, Ryan
Sent: Friday, July 10, 2015 1:29 PM
To: Glenn Schwendinger
Subject: RE: Milverton Natural Gas Pipeline Project EPP

Hi Glenn,

Just confirming if your received the digital version of our reports from RJBurnside.

Let me know if you need anything else at this time.

Cheers,
Ryan

From: Glenn Schwendinger [mailto:gschwendinger@pertheast.ca]
Sent: July-10-15 9:26 AM
To: Park, Ryan
Subject: Milverton Natural Gas Pipeline Project EPP

Hi Ryan

Would it be possible to get an electronic version of the document that you provided to us for comment? It would be much easier for us to circulate it internally for comments and review.
Thanks in advance.

Glenn Schwendinger
Chief Administrative Officer
Township of Perth East
25 Mill Street East
Milverton, ON
N0K 1M0
Telephone 1-519-595-2800
Fax 1-519-595-2801
gschwendinger@pertheast.ca

Tomek, Evan

From:	Park, Ryan
Sent:	September-28-15 2:00 PM
To:	'Theresa Campbell'
Cc:	Glenn Schwendinger
Subject:	RE: Union Gas Limited Community Expansion Program - Milverton Natural Gas Pipeline Project - Comments
Attachments:	Milverton Natural Gas Pipeline Project Comments 2015 Jul 23.pdf; Milverton Natural Gas Pipline UG Response 2015 Sept 28.pdf

Hi Theresa,

My apologies for the late response, please see the attached for responses to your comment submitted on July 23, 2015. Please let me know if you have any additional comments or questions.

Regards,

Ryan

Ryan Park, B.Sc., Can-CISEC
Senior Environmental Planner, Permitting & Environmental Planning
Union Gas Limited | A Spectra Energy Company
Ph: 519 436-2460 x5233007
Cell: 519 350-0289

From: Theresa Campbell [mailto:tcampbell@pertheast.ca]
Sent: July-23-15 11:58 AM
To: Park, Ryan
Cc: Glenn Schwendinger
Subject: Union Gas Limited Community Expansion Program - Milverton Natural Gas Pipeline Project - Comments

Hello Ryan,

Re: Union Gas Limited Community Expansion Program
Milverton Natural Gas Pipeline Project

Attached please find comments in response to your correspondence and the Milverton Natural Gas Pipeline Project Environmental Protection Plan received by the Township of Perth East on June 5th, 2015.

Should you require additional information regarding this matter, please contact Glenn Schwendinger, CAO at gschwendinger@pertheast.ca or 519-595-2800 ext. 232.

Thank you,

Theresa

Theresa Campbell, CMO
Municipal Clerk

Township of Perth East
25 Mill Street E.
Milverton, ON
N0K 1M0

519-595-2800 ext. 223
519-595-2801 (fax)

Township of Perth East

P.O. Box 455, 25 Mill Street
Milverton, Ontario N0K 1M0

Phone- (519) 595-2800
Fax- (519) 595-2801

Theresa Campbell, CMO
Municipal Clerk

email – tcampbell@pertheast.ca

July 23, 2015

Ryan Park via email rdpark@uniongas.com
Senior Environmental Planner
Union Gas Limited
750 Richmond Street
Chatham, ON
N7M 5J5

Re: Union Gas Limited Community Expansion Program
Milverton Natural Gas Pipeline Project

In response to correspondence received by the Township of Perth East on June 5th, 2015 and review of the Milverton Natural Gas Pipeline Project Environmental Protection Plan the Township of Perth East has the following comments;

Staff from public works, planning, and administration has reviewed the comprehensive report and feel that it generally addresses the necessary aspects of an undertaking such as this and is confident that it deals with environmental issues appropriately.

The following comments, while not necessarily environmental concerns, are appropriate to raise at this time, before matters progress to the point which could make it more difficult to address.

1. A comment/question that was identified by staff pertains to the proposed 4 inch main that is shown going through the future Gies subdivision and then heads east along Mill Street (See attached air photo). While this is not an environmental concern, it does pertain to the layout/construction. The question pertains to the timing and location of this particular section of gas main as it is shown going through a subdivision that is essentially draft only, has no final design and will be developed in phases which timing is unknown at this point. Concerns are that as the design is not final, the grades and configuration are not finalized nor is the layout of other services. Additionally, the land which will be future roadways is still in private ownership and therefore is not a current municipal right of way. If the main is required as part of the initial installation, then perhaps the 4 inch could be installed along Mill Street East. If the main is to be installed in the future, consideration should be given to having it installed in co-ordination with the development and installation of services of the subdivision, whenever that occurs.
2. With regard to sub-section 3.2 (Natural Features) of the Environmental Screening Report, if there is a potential for disruption to any such feature(s), the County's Planning and Development Department shall be contacted.
3. With regard to sub-section 3.3 (CA Reg. Lands) of the Environmental Screening Report, the respective CA's should be consulted on the project.

4. With regard to Section 4.0, sub 1., (tree protection measures) of the Environmental Screening Report, any required disruption of trees shall be in compliance with the "County of Perth By-law Number 2927 - Being a By-Law to prohibit or regulate the destruction or injuring of trees, in woodlands and woodlots in the County of Perth", found: http://www.perthcounty.ca/fileBin/library/council/bylaws/2005/bl2927_Forest_Conservation_Bylaw.pdf Questions on this issue should be referred to the County's Planning and Development Department.
5. The following highlight areas of roadways not owned by the Township- this may not pose a significant issue or concern for the construction, but should be noted:
6. The route on Road 130 will pass Line 38, which has been determined to be a "blind line"/"forced road"- The routing of the gas line may be entirely within the municipally-owned ROW for Road 130, but it should be noted that the two properties bounded by Road 130 and Line 38 have not yet been resolved in terms of municipal ownership.
7. At the S-bend between properties at Lot 16, Concession 5 and South Part of Lot 15, Concession 6, is a similar situation- the gas line will need to cross privately-owned properties, it appears.
8. Line 59, which crosses Perth Road 131, is also a "blind line"/"forced road", however the process has yet to start for transferring ownership to the Township.

Should you require additional information, please contact Glenn Schwendinger, CAO at gschwendinger@pertheast.ca or 519-595-2800 ext. 232.

Yours truly,

Theresa Campbell

Theresa Campbell, CMO
Municipal Clerk

cc. G. Schwendinger, CAO

uniongas
A Spectra Energy Company

September 30, 2015

Theresa Campbell, CMO
Municipal Clerk
P.O. Box 455
25 Mill Street
Milverton, Ontario
N0K 1M0
tcampbell@perth East

SENT ELECTRONICALLY VIA EMAIL

Dear Ms. Campbell,

Subject: **Union Gas Limited Community Expansion Program**
Milverton Natural Gas Pipeline Project

Further to the letter dated July 23, 2015 which was received, we have prepared the following response for your consideration.

1. Union Gas is planning on installing the 4" PE pipeline within the subdivision as it is constructed. This section of pipeline is not required when Union Gas installs the initial distribution system in Milverton. Union Gas will work with the Township and the developer to determine the location and timing of installation the pipeline within the subdivision.

2. All required environmental permit and approval will be obtained prior to the initiation of works, including those issued by the County of Perth. The County's Planning and Development Department shall be consulted for permitting requirement if there is the potential for disruption of the natural feature identified in Section 3.2 of the Environmental Screening Report.

3. Respective CA's (Maitland Valley Conservation Authority, Grand River Conservation Authority and Upper Thames River Conservation Authority) have received copies of the Environmental Protection Plan and Environmental Screening Report. All required permits and approvals for the respective CA's will be obtained prior to the initiation of works within regulated lands.

4. Any required disruption of trees will be completed in consultation with and the approval of the County's Planning and Development Department.

5. Union will be conducing detailed surveys the areas identified by the municipality in the near future to determine the exact location of the road allowance. After these studies have been completed Union will work with the municipality and adjacent landowners to determine the location of the proposed pipeline.

6. See Response # 5

7. See Response # 5

8. See Response # 5

If you have further questions or comments related to the Milverton Natural Gas Project please do not hesitate to contact us.

Yours Truly,

Mr. Ryan Park,
Senior Environmental Planner
rdpark@uniongas.com
519 436-2460 x5233007

Grand River Conservation Authority
400 Clyde Road, P.O. Box 729 Cambridge, ON N1R 5W6
Phone: 519.621.2761 Toll free: 866.900.4722 Fax: 519.621.4844 Online: www.grandriver.ca

July 27, 2015

Ryan Park, Senior Environmental Planner
Union Gas Ltd.
750 Richmond Street,
Chatham, ON N7M 5J5

Dear Mr. Park,

Subject: Union Gas Limited Community Expansion Program, Milverton Natural Gas Pipeline Project, Environmental Protection Plan

The Milverton Natural Gas Pipeline Project, Environmental Protection Plan addressed to Joe Farwell at the GRCA, has recently been forwarded to my attention for a response. Having reviewed the Environmental Protection Plan and the Project Location Maps, I can advise you that a very small portion of the project, located in the eastern half of Milverton, is located within the GRCA Watershed. The balance of the project is located in the Maitland Valley C.A.'s Watershed and the Upper Thames River C.A.'s Watershed.

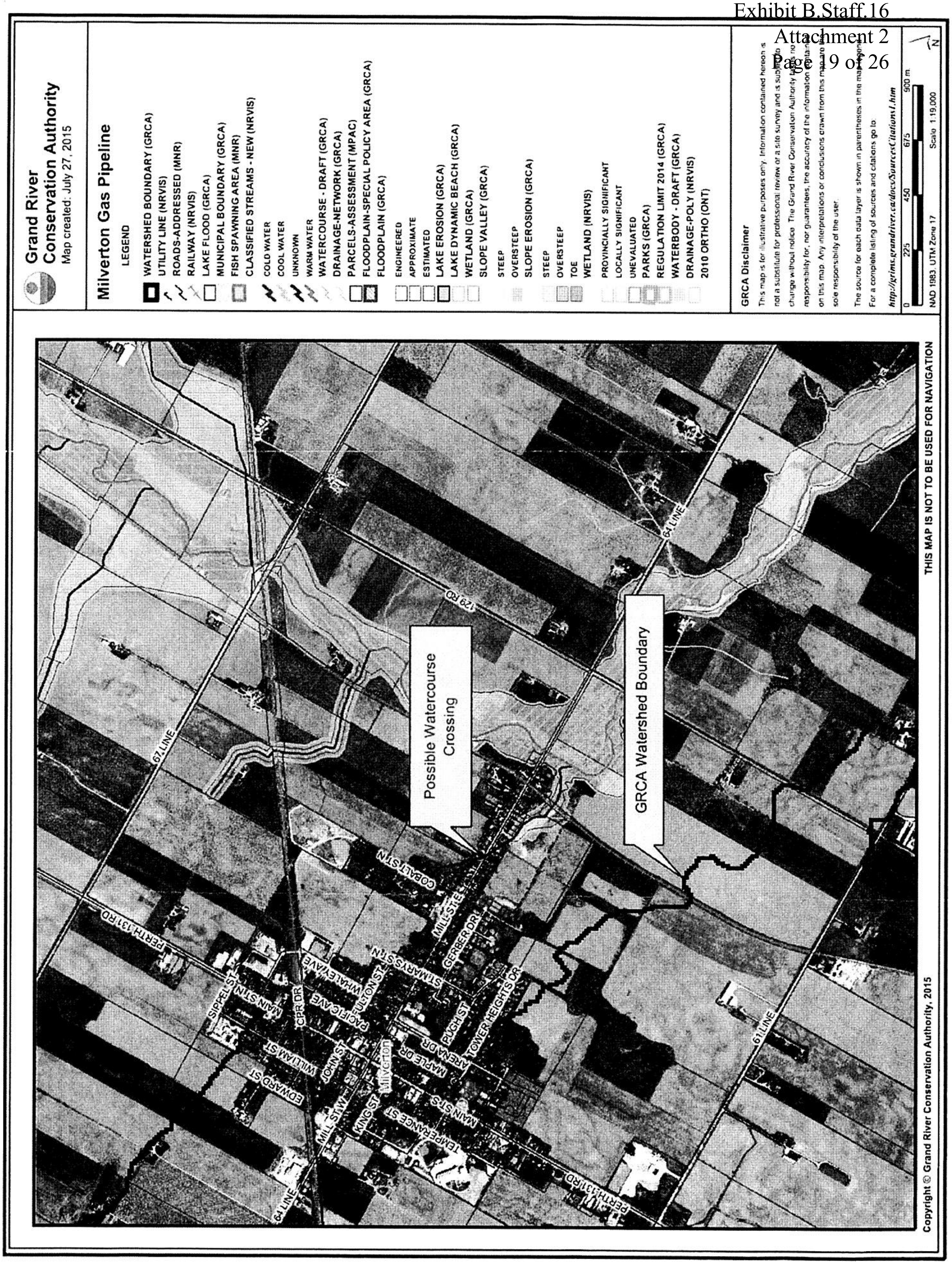
I have attached a copy of our GIS mapping for that portion of Milverton that is within our watershed. It would appear from the Project Location Maps that the only portion of the project that may affect our interests is the installation of the 2" plastic line along Mill St. East. It appears that this line crosses a tributary of Smith Creek. Although installation will be through Horizontal Directional Drilling, crossing a regulated watercourse is considered an alteration to that watercourse and would trigger the need for a permit. Similarly, any other watercourse crossings or culvert installations within the GRCA Watershed may require a permit.

Please advise when you are ready to proceed with the permit application and I can assist you.

Sincerely,

Drew Cherry

Drew Cherry
Resource Planner
Grand River Conservation Authority
519-621-2763 ext. 2237
dcherry@grandriver.ca


Grand River Conservation Authority
Map created: July 27, 2015
Milverton Gas Pipeline
LEGEND
WATERSHED BOUNDARY (GRCA)
UTILITY LINE (NRVIS)
ROADS-ADDRESSED (MNR)
RAILWAY (NRVIS)
LAKE FLOOD (GRCA)
MUNICIPAL BOUNDARY (GRCA)
FISH SPAWNING AREA (MNR)
CLASSIFIED STREAMS - NEW (NRVIS)
COLD WATER
COOL WATER
UNKNOWN
WARM WATER
WATERCOURSE - DRAFT (GRCA)
DRAINAGE-NETWORK (GRCA)
PARCELS-ASSESSMENT (MPAC)
FLOODPLAIN-SPECIAL POLICY AREA (GRCA)
FLOODPLAIN (GRCA)
ENGINEERED
APPROXIMATE
ESTIMATED
LAKE EROSION (GRCA)
LAKE DYNAMIC BEACH (GRCA)
WETLAND (GRCA)
SLOPE VALLEY (GRCA)
STEEP
OVERSTEEP
SLOPE EROSION (GRCA)
STEEP
OVERSTEEP
TOE
WETLAND (NRVIS)
PROVINCIALLY SIGNIFICANT
LOCALLY SIGNIFICANT
UNEVALUATED
PARKS (GRCA)
REGULATION LIMIT 2014 (GRCA)
WATERBODY - DRAFT (GRCA)
DRAINAGE-POLY (NRVIS)
2010 ORTHO (ONT)
GRCA Disclaimer
This map is for illustrative purposes only. Information contained hereon is not a substitute for professional review or a site survey and is subject to change without notice. The Grand River Conservation Authority takes no responsibility for, nor guarantees, the accuracy of the information contained on this map. Any interpretations or conclusions drawn from this map are the sole responsibility of the user.
The source for each data layer is shown in parentheses in the map legend.
For a complete listing of sources and citations go to:
http://grims.grandriver.ca/docs/SourcesCitations1.htm
0 225 450 675 900 m
NAD 1983 UTM Zone 17
Scale 1:19,000
Possible Watercourse Crossing
GRCA Watershed Boundary
67 LINE
64 LINE
61 LINE
129 RD
PERTH 131 RD
COBALT ST N
MILL ST E
GERBER DR
ST MARYS ST N
WHALEY AVE
FULTON ST
PACIFIC AVE
CPR DR
MAIN ST N
SIPPEL ST
WILLIAM ST
EDWARD ST
JOHN ST
Milverton
MAPLE DR
ARENA DR
PUGH ST
TOWER HEIGHTS DR
MILL ST W
KING ST
TEMPERANCE ST
MAIN ST S
THIS MAP IS NOT TO BE USED FOR NAVIGATION
Copyright © Grand River Conservation Authority, 2015

Tomek, Evan

From:	Muller, Joseph (MTCS) <Joseph.Muller@ontario.ca>
Sent:	August-06-15 4:09 PM
To:	zora.crnojacki@ontarioenergyboard.ca
Cc:	Park, Ryan
Subject:	Union Gas Limited Community Expansion Program
Attachments:	UG Kettle Point Lambton Shores 2015-08-06 CSU MTCS Comments.pdf; UG Milverton - Perth East - Perth 2015-08-06 CSU MTCS Comments.pdf

Hello Zora Crnojacki:

Please find attached our comments from the Culture Services Unit at the Ministry of Tourism, Culture and Sport on the following projects:

Kettle Point / Lambton Shores Natural Gas Pipeline Project; and,
Milverton Natural Gas Pipeline Project.

I may be contacted for any questions or discussion of our comments on these files. Thank-you for your assistance,

Joe

Joseph Muller, RPP, MCIP

Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Division | Programs and Services Branch | Culture Services Unit

401 Bay Street, Suite 1700
Toronto, Ontario M7A 0A7

Tel. 416.314.7145 | Fax. 416.314.7175

Ministry of Tourism, Culture and Sport

Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto ON M7A 0A7
Tel: 416 314 7145
Fax: 416 212 1802

Ministère du Tourisme, de la Culture et du Sport

Unité des services culturels
Direction des programmes et des services
401, rue Bay, Bureau 1700
Toronto ON M7A 0A7
Tél: 416 314 7145
Téléc: 416 212 1802

Ontario

August 6, 2015 (EMAIL ONLY)

Zora Crnojacki, Coordinator
Ontario Pipeline Coordination Committee
Ontario Energy Board
Suite 2601, 2300 Yonge Street
Toronto, ON M4P 1E4
E: zora.crnojacki@ontarioenergyboard.ca

RE:	**MTCS file #:**	**0002991**
	Proponent:	**Union Gas**
	Subject:	**Environmental Protection Plan Milverton Natural Gas Pipeline Project**
	Location:	**Municipality of Perth East, Perth County, Ontario**

Dear Zora Crnojacki:

The Ministry of Tourism, Culture and Sport (MTCS) is in receipt of the Environmental Protection Plan for the above project. MTCS's interest in this EA project relates to its mandate of conserving Ontario's cultural heritage, which includes:

- Archaeological resources, including land-based and marine;
- Built heritage resources, including bridges and monuments; and,
- Cultural heritage landscapes.

Under the ER process for Ontario Energy Board projects, the proponent is required to determine a project's potential impact on cultural heritage resources. MTCS should be provided with any archaeological assessment and/or cultural heritage assessment reports completed for the above project prior to issuance of a Notice of Completion.

While some cultural heritage resources may have already been formally identified, others may be identified through screening and evaluation. Aboriginal communities may have knowledge that can contribute to the identification of cultural heritage resources, and we suggest that any engagement with Aboriginal communities includes a discussion about known or potential cultural heritage resources that are of value to these communities. Municipal Heritage Committees, historical societies and other local heritage organizations may also have knowledge that contributes to the identification of cultural heritage resources.

Archaeological Resources
It is understood from the Environmental Protection Plan that a Stage 1 archaeological assessment (AA) shall be undertaken by an archaeologist licenced under the *OHA*, who is responsible for submitting the report directly to MTCS for review. While construction is described as remaining entirely within the disturbed portion of the road allowance, we note that this corridor comprises an original concession road, built prior to archaeological assessments, and so may intersect as yet unregistered archaeological sites. The scope of soil disturbance related to the project also includes proposed regulating stations and may involve temporary staging and stockpiling areas and access routes which may be relatively undisturbed. As a result, we advise against presuming that there will be no impacts to archaeological resources and instead recommend including the weighting of actual or potential impacts in the evaluation of alternatives.

Built Heritage and Cultural Heritage Landscapes
The Environmental Protection Plan confirms that the study area will be screened for potential built heritage and cultural heritage landscapes. The MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* should be completed to help determine potential impacts to impact cultural heritage resources. The Clerks for the Municipality of Perth East and Perth County can provide information on property registered or designated under the *Ontario Heritage Act*. Municipal Heritage Planners can also provide information to complete the checklist.

If potential or known heritage resources exist, MTCS recommends that a Heritage Impact Assessment (HIA), prepared by a qualified consultant, should be completed to assess potential project impacts. Our Ministry's *Info Sheet #5: Heritage Impact Assessments and Conservation Plans* outlines the scope of HIAs. Any HIA completed is to be sent to MTCS for review, and made available to local organizations or individuals who have expressed interest in heritage.

Environmental Assessment Reporting
All technical heritage studies and their recommendations are to be addressed and incorporated into EA projects. Technical heritage studies completed for the EA project are to be provided to MTCS before a Notice of Completion is issued. If screening has identified no known or potential cultural heritage resources, or no impacts to these resources, the completed checklists and supporting documentation should be included in the EA report or file.

MTCS requests continued circulation through the EA process: I may be contacted for any questions or clarification.

Sincerely,

Joseph Muller, RPP/MCIP
Heritage Planner
Joseph.Muller@Ontario.ca

Copied to: Ryan Park, Senior Environmental Planner, Union Gas

It is the sole responsibility of proponents to ensure that any information and documentation submitted as part of their EA report or file is accurate. MTCS makes no representation or warranty as to the completeness, accuracy or quality of the any checklists, reports or supporting documentation submitted as part of the EA process, and in no way shall MTCS be liable for any harm, damages, costs, expenses, losses, claims or actions that may result if any checklists, reports or supporting documents are discovered to be inaccurate, incomplete, misleading or fraudulent.

MTCS must be notified if archaeological resources are impacted by EA project work. All activities impacting archaeological resources must cease immediately, and a licensed archaeologist is required to carry out an archaeological assessment in accordance with the Ontario Heritage Act and the Standards and Guidelines for Consultant Archaeologists.

If human remains are encountered, all activities must cease immediately and the local police as well as the Cemeteries Regulation Unit of the Ministry of Government and Consumer Services must be contacted. In situations where human remains are associated with archaeological resources, MTCS should also be notified to ensure that the site is not subject to unlicensed alterations which would be a contravention of the Ontario Heritage Act.

Tomek, Evan

From:	Tomek, Evan
Sent:	November-23-15 12:42 PM
To:	'Joseph.Muller@Ontario.ca'
Subject:	Community Expansion Program Update
Attachments:	MTCS Moraviantown Update.pdf; MTCS Walpole Update.pdf; MTCS Milverton Update.pdf; MTCS KP LS Update.pdf

Good Afternoon Joseph,

Thank you for your reviews of Union Gas' Environmental Protection Plans for our Moraviantown, Walpole Island, Milverton, and Kettle Point / Lambton Shores Natural Gas Pipeline Projects.
I have attached four letters providing an update regarding our Archaeology and Cultural Heritage works for each project.
I appreciate your time with these reviews, and if you have any questions don't hesitate to ask.

Thanks,

Evan

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: etomek@uniongas.com

Canada's Top 100 Employers 2015

uniongas
A Spectra Energy Company

November 23, 2015 (VIA EMAIL)

Joseph Muller, Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto, ON M7A 0A7
Email: Joseph.Muller@Ontario.ca

RE: Milverton Natural Gas Pipeline Project

Dear Mr. Muller,

Thank you for your review of the report entitled, *Milverton Natural Gas Pipeline Project Environmental Protection Plan, May 2015,* and subsequent letter dated August 6, 2015. We appreciate you taking the time to review the report and provide important feedback.

Union Gas Limited (Union) retained the services of Stantec Consulting Ltd. (Stantec) to complete a Stage 1 and 2 Archaeological Assessment of the proposed pipeline project area to identify potential impacts to archaeological resources. The Stage 1 Archaeological Assessment report was completed and submitted to the Ministry on November 17, 2015. The Stage 1 report recommended that a Stage 2 Archaeological Assessment be conducted on portions of the project area that exhibit a moderate to high potential for the identification and recovery of archaeological resources. The Stage 2 surveys will be completed in the near future with the submission of the Stage 2 Archaeological Assessment report to follow.

Union retained the services of Stantec to identify potential built heritage and cultural heritage landscapes in the project area. Stantec consulted the Ministry, the Ontario Heritage Trust, and the Township of Perth East to identify such features. Currently, the *Overview of Heritage Resources* report is being finalized for submission to the Ministry and the Ministry's *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed.

Thank you again for your time and we will notify you of the submission of the aforementioned reports. If you have any questions do not hesitate to ask.

Yours Truly,

Evan Tomek
Environmental Planner
Union Gas Limited
Tel: 519.436.2460 ext 5236904
Email: etomek@uniongas.com

Tomek, Evan

From:	Marriott, David (MNRF) <David.Marriott@ontario.ca>
Sent:	September-03-15 9:22 AM
To:	Park, Ryan
Subject:	FW: Milverton Natural Gas Pipeline Project - MNRF Comments

Hi Ryan,

I apologize for the delay in responding.

The Ministry of Natural Resources and Forestry (MNRF) Guelph District Office is in receipt of the 'Milverton Natural Gas Pipeline Project' Environmental Protection Plan (EPP). It is understood that the project will include the installation of approx. 20 kilometers of new pipeline (NPS 4 inch diameter) along East Perth Road and Perth Road 131. A new distribution regulation station is also proposed near the Perth Road 131 and Line 61 intersection. The EPP is intended to support the project by defining the natural heritage features in the project area, and provide recommended mitigation measures to minimize any potential negative impacts to these features. MNRF staff have had an opportunity to review the EPP, and can offer the project team the following species at risk comments for consideration.

EPP Comments

Species at Risk Comments

- Section 4.0 of the EPP provides some direction for tree protection measures. The MNRF notes that Butternut is known for Perth County, and the species receives both individual and general habitat protection under the *Endangered Species Act* (ESA). If the project has the potential to remove or damage any trees, it is recommended that the trees first be identified to determine if they are listed under the ESA. Under Ontario Regulation 242/08, certain activities are allowed that would impact endangered and threatened species, provided the requirements of the exemption regulations are followed. Butternut is included in these exemption regulations under Section 23.7 If Butternut may be impacted, it is recommended that the project team refer to Section 23.7 to determine whether the project may qualify for registration.

  In addition to the above, for any tree proposed for removal, it is recommended that a qualified individual assess the suitability of the tree for potential habitat of endangered bats prior to removal. The MNRF notes that two endangered bat species (Little Brown Myotis and Northern Myotis) under the ESA are suspected to occur in Perth County. If a tree proposed for removal is identified as potential bat roosting habitat, it is recommended that a survey be undertaken by a qualified individual in accordance with MNRF's survey protocol to determine presence/absence of listed bats. This survey protocol can be provided on request.

- Records for Snapping Turtle (special concern) and Eastern Milksnake (special concern) are present in the vicinity of the project area. This is noted in Section 3.2.4 of the EPP. The EPP has identified that the potential for Milksnake habitat in the work area is low, but Snapping Turtles is likely to occur. Prior to construction of the project, the project team may wish to apply for a Wildlife Scientific Collectors authorization under the *Fish and Wildlife Conservation Act* in order to have the authority to capture and relocate any turtles or snakes (not listed as threatened or endangered species) moving through the construction area. If Snapping Turtles are found nesting in the project area, the MNRF can be contacted for further direction, as noted in the EPP.

- With respect to potential impacts on Bobolink (threatened) and Eastern Meadowlark (threatened) and their habitat, the EPP identifies that most of the farm fields in the area support more intensive row crop agricultural (e.g., soybeans, corn, wheat) and that the pipeline is to be installed within existing road right-of-ways as close as possible to the road edge. The EPP also states that if the pipeline must be installed within a fallow field or pasture, work should occur outside of the breeding bird season. If this is not possible, a nest survey by a qualified biologist prior to construction should be completed. If the project has the potential to impact Bobolink or Eastern Meadowlark habitat during the breeding bird season, the MNRF recommends that the project team refer to the exemption regulation under Section 23.6 of Ontario Regulation 242/08 to determine whether the project may qualify for registration.

Please contact the undersigned if further comment or clarification is required.

Thanks

Dave

Dave Marriott
District Planner
Ministry of Natural Resources and Forestry, Guelph District
1 Stone Road West
Guelph ON, N1G 4Y2
(P) 519-826-4926
(F) 519-826-6849
email: david.marriott@ontario.ca

OPCC Review Summary

Moraviantown Natural Gas Pipeline Project

AGENCY	COMMENT	RESPONSE
Technical Standards & Safety Authority (TSSA) Email dated June 19, 2015	The documentation submitted is compliant with our regulation and the documentation has been submitted to Mr. Mike Davis, Regional Supervisor, TSSA Inspection. The construction and/or commissioning of the extensions may be subject to an inspection.	Not Required.
Ministry of Tourism, Culture & Sport (MTCS) Email and letter dated August 6, 2015	Email containing a letter to Zora Crnojacki: Provide MTCS with any archaeological assessment and/or cultural heritage assessment reports and/or technical heritage study prior to issuance of a Notice of Completion. Engagement with Aboriginal communities should include a discussion about known or potential cultural heritage resources and other local heritage organization should be consulted as required. Avoid assuming there will be no impacts to archaeological resources; recommend including the weighting of actual or potential impacts in the evaluation of alternatives. The MTCS Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes should be completed and included in the EA report or file. A Heritage Impact Assessment is recommended if potential or known heritage resources exist. MTCS requests continued circulation through the EA process.	Email containing a letter dated November 23, 2015: Engagement with Delaware Nation at Moraviantown has been ongoing from the onset of the Stage 1 Archaeological Assessment and cultural heritage study. Archaeological monitors from Delaware Nation at Moraviantown, Walpole Island First Nation, and Chippewas of Kettle and Stony Point First Nation were involved in Stage 2 surveys. No sites have been discovered and the Stage 1 and 2 Archaeological Assessment Report is being finalized for submission to the MTCS. An *Overview of Heritage Resources* report is being finalized and the MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed.

Tomek, Evan

From: Oscar Alonso <oalonso@tssa.org>
Sent: June-19-15 4:00 PM
To: Tomek, Evan; Mike Davis
Cc: Zora Crnojacki
Subject: Community Expansion Program. Projects for Walpole Island and Township and Moraviantown.

Dear Mr. Tomek,

Thanks for the information on the Community Expansion Program for these two projects. The documentation submitted is compliant with our regulation and the documentation has been submitted to Mr. Mike Davis, Regional Supervisor, TSSA Inspection.

The construction and or commissioning of the extensions may be subject to an inspection.

Yours truly,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

Tomek, Evan

From:	Muller, Joseph (MTCS) <Joseph.Muller@ontario.ca>
Sent:	August-06-15 4:13 PM
To:	zora.crnojacki@ontarioenergyboard.ca
Cc:	Tomek, Evan
Subject:	Union Gas Limited Community Expansion Program
Attachments:	UG Moraviantown - Chatham-Kent 2015-08-06 CSU MTCS Comments.pdf; UG Walpole Island FN -2015-08-06 CSU MTCS Comments.pdf

Hello Zora Crnojacki:

Please find attached our comments from the Culture Services Unit at the Ministry of Tourism, Culture and Sport on the following projects:

> Moraviantown Natural Gas Pipeline Project; and,
> Walpole Island Natural Gas Pipeline Project.

I may be contacted for any questions or discussion of our comments on these files. Thank-you for your assistance,

Joe

Joseph Muller, RPP, MCIP

Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Division | Programs and Services Branch | Culture Services Unit

401 Bay Street, Suite 1700
Toronto, Ontario M7A 0A7

Tel. 416.314.7145 | Fax. 416.314.7175

Ministry of Tourism, Culture and Sport

Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto ON M7A 0A7
Tel: 416 314 7145
Fax: 416 212 1802

Ministère du Tourisme, de la Culture et du Sport

Unité des services culturels
Direction des programmes et des services
401, rue Bay, Bureau 1700
Toronto ON M7A 0A7
Tél: 416 314 7145
Téléc: 416 212 1802

Ontario

August 6, 2015 (EMAIL ONLY)

Zora Crnojacki, Coordinator
Ontario Pipeline Coordination Committee
Ontario Energy Board
Suite 2601, 2300 Yonge Street
Toronto, ON M4P 1E4
E: zora.crnojacki@ontarioenergyboard.ca

RE:	**MTCS file #:**	**0002992**
	Proponent:	**Union Gas**
	Subject:	**Environmental Protection Plan Moraviantown Natural Gas Pipeline Project**
	Location:	**Delaware Nation, Municipality of Chatham-Kent, Ontario**

Dear Zora Crnojacki:

The Ministry of Tourism, Culture and Sport (MTCS) is in receipt of the Environmental Protection Plan for the above project. MTCS's interest in this EA project relates to its mandate of conserving Ontario's cultural heritage, which includes:

- Archaeological resources, including land-based and marine;
- Built heritage resources, including bridges and monuments; and,
- Cultural heritage landscapes.

Under the ER process for Ontario Energy Board projects, the proponent is required to determine a project's potential impact on cultural heritage resources. MTCS should be provided with any archaeological assessment and/or cultural heritage assessment reports completed for the above project prior to issuance of a Notice of Completion.

While some cultural heritage resources may have already been formally identified, others may be identified through screening and evaluation. Aboriginal communities may have knowledge that can contribute to the identification of cultural heritage resources, and we suggest that any engagement with Aboriginal communities includes a discussion about known or potential cultural heritage resources that are of value to these communities. Municipal Heritage Committees, historical societies and other local heritage organizations may also have knowledge that contributes to the identification of cultural heritage resources.

Archaeological Resources
It is understood from the Environmental Protection Plan that a Stage 1 archaeological assessment (AA) shall be undertaken by an archaeologist licenced under the *OHA*, who is responsible for submitting the report directly to MTCS for review. While construction is described as remaining entirely within the disturbed portion of the road allowance, we note that many of these corridors comprise original concession and early settlement roads, built prior to archaeological assessments, and so may intersect as yet unregistered archaeological sites. The scope of soil disturbance related to the project also includes proposed regulating stations and may involve temporary staging and stockpiling areas and access routes which may be relatively undisturbed. As a result, we advise against presuming that there will be no impacts to archaeological resources and instead recommend including the weighting of actual or potential impacts in the evaluation of alternatives.

Built Heritage and Cultural Heritage Landscapes
The Environmental Protection Plan confirms that the study area will be screened for potential built heritage and cultural heritage landscapes. The MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* should be completed to help determine potential impacts to impact cultural heritage resources. Delaware Nation and the Clerk for the Municipality of Chatham-Kent can provide information on property registered or designated under the *Ontario Heritage Act*. Municipal Heritage Planners can also provide information to complete the checklist.

If potential or known heritage resources exist, MTCS recommends that a Heritage Impact Assessment (HIA), prepared by a qualified consultant, should be completed to assess potential project impacts. Our Ministry's *Info Sheet #5: Heritage Impact Assessments and Conservation Plans* outlines the scope of HIAs. Any HIA completed is to be sent to MTCS for review, and made available to local organizations or individuals who have expressed interest in heritage.

Environmental Assessment Reporting
All technical heritage studies and their recommendations are to be addressed and incorporated into EA projects. Technical heritage studies completed for the EA project are to be provided to MTCS before a Notice of Completion is issued. If screening has identified no known or potential cultural heritage resources, or no impacts to these resources, the completed checklists and supporting documentation should be included in the EA report or file.

MTCS requests continued circulation through the EA process: I may be contacted for any questions or clarification.

Sincerely,

Joseph Muller, RPP/MCIP
Heritage Planner
Joseph.Muller@Ontario.ca

Copied to: Ryan Park, Senior Environmental Planner, Union Gas

It is the sole responsibility of proponents to ensure that any information and documentation submitted as part of their EA report or file is accurate. MTCS makes no representation or warranty as to the completeness, accuracy or quality of the any checklists, reports or supporting documentation submitted as part of the EA process, and in no way shall MTCS be liable for any harm, damages, costs, expenses, losses, claims or actions that may result if any checklists, reports or supporting documents are discovered to be inaccurate, incomplete, misleading or fraudulent.

MTCS must be notified if archaeological resources are impacted by EA project work. All activities impacting archaeological resources must cease immediately, and a licensed archaeologist is required to carry out an archaeological assessment in accordance with the Ontario Heritage Act and the Standards and Guidelines for Consultant Archaeologists.

If human remains are encountered, all activities must cease immediately and the local police as well as the Cemeteries Regulation Unit of the Ministry of Government and Consumer Services must be contacted. In situations where human remains are associated with archaeological resources, MTCS should also be notified to ensure that the site is not subject to unlicensed alterations which would be a contravention of the Ontario Heritage Act.

Tomek, Evan

From:	Tomek, Evan
Sent:	November-23-15 12:42 PM
To:	'Joseph.Muller@Ontario.ca'
Subject:	Community Expansion Program Update
Attachments:	MTCS Moraviantown Update.pdf; MTCS Walpole Update.pdf; MTCS Milverton Update.pdf; MTCS KP LS Update.pdf

Good Afternoon Joseph,

Thank you for your reviews of Union Gas' Environmental Protection Plans for our Moraviantown, Walpole Island, Milverton, and Kettle Point / Lambton Shores Natural Gas Pipeline Projects.
I have attached four letters providing an update regarding our Archaeology and Cultural Heritage works for each project.
I appreciate your time with these reviews, and if you have any questions don't hesitate to ask.

Thanks,

Evan

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: etomek@uniongas.com

uniongas
A Spectra Energy Company

November 23, 2015 (VIA EMAIL)

Joseph Muller, Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto, ON M7A 0A7
Email: Joseph.Muller@Ontario.ca

RE: Moraviantown Natural Gas Pipeline Project

Dear Mr. Muller,

Thank you for your review of the report entitled, *Moraviantown Natural Gas Pipeline Project Environmental Protection Plan, May 2015,* and subsequent letter dated August 6, 2015. We appreciate you taking the time to review the report and provide important feedback.

Union Gas Limited (Union) retained the services of D.R. Poulton & Associates to complete a Stage 1 and 2 Archaeological Assessment of the proposed pipeline project area to identify potential impacts to archaeological resources. Members of Delaware Nation at Moraviantown were involved from the onset of the Stage 1 archaeological survey to contribute to the identification of potential archaeological resources on June 26, 2015 during a meeting and tour of the proposed pipeline route. Archaeological monitors from Delaware Nation at Moraviantown, Walpole Island First Nation, and Chippewas of Kettle and Stony Point were also present for a Stage 2 archaeological survey on October 16, 2015. Currently, the Stage 2 archaeological survey of the proposed pipeline route has been completed with no sites discovered. The Stage 1 and 2 Archaeological Assessment report is being finalized for submission to the Ministry.

Union retained the services of Stantec Consulting Ltd. (Stantec) to identify potential built heritage and cultural heritage landscapes in the project area. Stantec has consulted the Municipality of Chatham-Kent, the Ontario Heritage Trust, and worked with Delaware Nation at Moraviantown to identify such features. Currently, the *Overview of Heritage Resources* report is being finalized for submission to the Ministry and the Ministry's *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed.

Thank you again for your time and we will notify you of the submission of the aforementioned reports. If you have any questions do not hesitate to ask.

Yours Truly,

Evan Tomek
Environmental Planner
Union Gas Limited
Tel: 519.436.2460 ext 5236904
Email: etomek@uniongas.com

OPCC Review Summary

Prince Township Natural Gas Pipeline Project

AGENCY	COMMENT	RESPONSE
Ministry of Environment and Climate Change Email dated June 8, 2015	Requested an electronic copy of the Environmental Protection Plan to circulate internally for comments.	Forwarded an electronic copy of the EPP on June 8, 2015.
Prince Township Phone Call from Peggy Greco on June 11, 2015	Asked if there was a plan to install piping on Marshall Drive. Requested an electronic copy of EPP to forward to councilors.	Union is proposing to service the first two houses on Marshall Drive. The other houses are too far apart and would have to pay to extend gas service down the road. Forwarded an electronic copy of the EPP on June 11, 2015.
Ministry of Tourism, Culture and Sport Email and letter Dated June 12, 2015	Email containing a letter to Zora Crnojacki: Archaeological Assessment and Heritage Impact Assessment should be undertaken by a licensed consultant archaeologist and qualified heritage consultant prior to any construction activity being undertaken. Suggestion to consult the Township and its municipal heritage committee, if one exists, concerning built heritage and cultural heritage landscapes. Notify MTCS if any of these buildings or landscapes have potential provincial significance.	Email containing a letter dated November 23, 2015: A Stage 1 Archaeological Assessment report was submitted on September 16, 2015 with no Stage 2 recommendation. A Cultural Heritage Assessment report is being finalized for submission to the MTCS and the MTCS *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes* has been completed. The MTCS, Ontario Heritage Trust, and Prince Township was consulted during the cultural heritage study.
Technical Standards & Safety Authority (TSSA) Email dated June 19, 2015	The documentation submitted is compliant with our regulation and the documentation has been submitted to Mr. Mike Davis, Regional Supervisor, TSSA Inspection. The construction and/or commissioning of the extensions may be subject to an inspection.	Not required.
Ministry of Environment and Climate Change Email dated June 22, 2015	No internal feedback received yet, but the data seems okay. If feedback or concerns from others in the MOECC is received you will be notified.	Not required.
Technical Standards & Safety	Reviewed the EPP and the	Not required.

Authority (TSSA) Email dated July 6, 2015	pipeline specifications. The polyethylene pipe specs meet the present code requirements. Although the pipeline is scheduled to be constructed in the summer of 2016, when the new CSA Z662-15 is expected to be in effect, we don't see any requirements in the new code that would impose changes in the pipe design, installation or operation.	
Ministry of Natural Resources and Forestry (MNRF), Sault Ste. Marie Region Email dated August 5, 2015	Reviewed the EPP and provided the following comments: 1. Please identify the EA Act coverage in relation to the project and the process to be followed. Also, clearly demonstrate any requirements under the EA Act that will apply to all components of the project. 2. A work permit may be required to conduct work on Crown land and water crossings. Further information regarding the location of any Crown land and water crossing within the project area is required. 3. If tree clearing is required, it is recommend that the qualified ornithologist contact/consult the MNRF District prior to conducting surveys. Recommended that you contact the MNRF district concerning potentially endangered bat species if tree clearing is required. 4. An permit under the *Endangered Species Act, 2007 (ESA)* may be required. The consultant should contact the MNRF district office to discuss the *Endangered Species Act 2007* and the proposed works. The *Endangered*	Email response on August 14, 2015: 1. The Prince Township Natural Gas Pipeline Project will be subject to the Ontario Energy Board Act and approval from the OEB is required before the project can proceed. An Environmental Protection Plan (EPP) has been completed to meet the intent of the Ontario Energy Board Environmental Guidelines for the Location Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 6th Edition 2011. 2. At this time all work is proposed within in the road allowance. Union or its Consultant will be in contact to discuss permit requirements. 3. Noted. Thank you. Noted. Thank you. Also, a qualified terrestrial biologist has completed a review of the Natural Heritage Information Centre database that did not reveal any records of at risk bat species in the vicinity of the project. Union or its Consultant will contact MNRF for further discussion. 4. Noted. Thank you.

	Species Act, 2007 applies on both Crown and private lands.	

Tomek, Evan

From:	Shields, Walter (MOECC) <Walter.Shields@ontario.ca>
Sent:	June-22-15 9:06 AM
To:	Tomek, Evan
Subject:	FW: Prince Township Natural Gas Pipeline Project

Hi Evan

Still no feedback yet, however I looked over your data and it seems okay, if I get feedback or concerns from others in the MOECC as noted below I will let you know.

Walter

Walter Shields
Tel: 705-942-6348
E-Mail: walter.shields@ontario.ca

From: Shields, Walter (MOECC)
Sent: June-17-15 1:55 PM
To: Shields, Walter (MOECC)
Subject: RE: Prince Township Natural Gas Pipeline Project

Hi Carrie
Any feedback yet.
Walter

Walter Shields
Tel: 705-942-6348
E-Mail: walter.shields@ontario.ca

From: Shields, Walter (MOECC)
Sent: June-08-15 3:49 PM
To: Hutchison, Carrie (MOECC); Tomek, Evan
Subject: FW: Prince Township Natural Gas Pipeline Project

Hi Carrie

How do we handle the attached request as noted in the cover letter.

Thanks Walter

Walter Shields
Tel: 705-942-6348
E-Mail: walter.shields@ontario.ca

From: Tomek, Evan [mailto:ETomek@spectraenergy.com]
Sent: June-08-15 3:26 PM
To: Shields, Walter (MOECC)
Subject: RE: Prince Township Natural Gas Pipeline Project

Hi Walter,

Here is the digital copy of the Environmental Protection Plan, and the Generic Sediment Control Plan for Horizontal Directional Drill (Appendix 3 of the EPP).

Thank you for your review of the EPP. Please contact me if you have any questions.

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: ETomek@spectraenergy.com

Canada's Top 100 Employers 2015

From: Shields, Walter (MOECC) [mailto:Walter.Shields@ontario.ca]
Sent: June-08-15 3:21 PM
To: Tomek, Evan
Subject: Prince Township Natural Gas Pipeline Project

Hi Evan
Can you send me a digital copy of the Environmental Protection Plan, so I can send it for comments.

Thanks

Walter Shields
Senior Environmental Officer
Ministry of the Environment
70 Foster Drive, Suite 110
Sault Ste. Marie ON, P6A 6V4
Tel: 705-942-6348
Fax: 705-942-6327
E-Mail: walter.shields@ontario.ca

Tomek, Evan

From: Kirzati, Katherine (MTCS) [mailto:Katherine.Kirzati@ontario.ca]
Sent: June-12-15 9:54 AM
To: Tomek, Evan
Subject: 0002989 -Prince Twp -Union Gas Pipeline Project

Good morning:

Please find attached MTCS' acknowledgement letter on the above-noted file.

If you have any questions, do not hesitate to contact me.

Regards, Katherine

Katherine Kirzati
[illegible]
Culture Services Unit
Ministry of Tourism, Culture and Sport
401 Bay Street, Suite 1700

Ministry of Tourism, Culture and Sport

Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto ON M7A 0A7
Tel: 416 314 7265
Fax: 416 314 7175

Ministère du Tourisme, de la Culture et du Sport

Unité des services culturels
Direction des programmes et des services
401, rue Bay, Bureau 1700
Toronto ON M7A 0A7
Tél: 416 314 7265
Téléc: 416 314 7175

Ontario

12 June 2015

Zora Crnojacki
Coordinator
Ontario Pipeline Coordination Committee
Ontario Energy Board
2300 Yonge Street
26th Floor, Suite 2601
Toronto, ON M4P 1E4

Via E-mail

Dear Ms. Crnojacki:

Our File No. : 00002989
Proponent : Union Gas Limited
Subject : Prince Township Natural Gas Pipeline Project
Location : Township of Prince, District of Algoma

The Ministry of Tourism, Culture and Sport's interest in the above-noted project relates to our mandate of conserving, protecting and preserving Ontario's heritage, including archaeological resources, built heritage resources and cultural heritage landscapes.

Project Summary

This undertaking involves the construction of a lateral pipeline (approximately 22.3 km in length) from an existing 4-inch plastic pipeline in Sault Ste Marie to service 14 specific locations in Prince Township.

Comments

We note in the Environmental Protection Plan report, dated May 2015, that Union Gas will undertake an archaeological assessment and a heritage impact assessment. These should be conducted by a licensed consultant archaeologist and a qualified heritage consultant prior to any construction activity being initiated.

With respect to built heritage and cultural heritage landscapes, we suggest that the applicant also consult the Township and its municipal heritage committee, if one exists. Our office should be notified if any of these buildings or landscapes are identified as being of potential provincial significance.

If you have any questions, please do not hesitate to contact the undersigned.

Yours truly,
Katherine Kirzati
Heritage Planner
416.314.7643
katherine.kirzati@ontario.ca

c: Evan Tomek, Union Gas Limited

Tomek, Evan

From:	Tomek, Evan
Sent:	November-23-15 12:44 PM
To:	'Kirzati, Katherine (MTCS)'
Subject:	Prince Township Update
Attachments:	MTCS PT Update.pdf

Hi Katherine,

Thank you for your review of the Prince Township Natural Gas Pipeline Project Environmental Protection Plan.
I have attached a letter containing an update regarding the archaeology and cultural heritage works associated with this project.
I appreciate your review, and if you have any questions don't hesitate to ask.

Thanks,

Evan

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: etomek@uniongas.com

uniongas
A Spectra Energy Company

November 23, 2015 (VIA EMAIL)

Katherine Kirzati, Heritage Planner
Ministry of Tourism, Culture and Sport
Culture Services Unit
Programs and Services Branch
401 Bay Street, Suite 1700
Toronto, ON M7A 0A7
Email: katherine.kirzati@ontario.ca

RE: Prince Township Natural Gas Pipeline Project

Dear Ms. Kirzati,

Thank you for your review of the report entitled, *Prince Township Natural Gas Pipeline Project Environmental Protection Plan, May 2015,* and subsequent letter dated June 12, 2015. We appreciate you taking the time to review the report and provide important feedback.

Union Gas Limited (Union) retained the services of Woodland Heritage Services to complete a Stage 1 Archaeological Assessment of the proposed pipeline project area to identify potential impacts to archaeological resources. The Stage 1 Archaeological Assessment report was completed and submitted to the Ministry on September 16, 2015. The Stage 1 report determined that no archaeological potential was found to exist along the proposed pipeline route.

Union retained the services of Unterman McPhail Heritage Resource Management Consultants (Unterman McPhail) to identify potential built heritage and cultural heritage landscapes in the project area. Unterman McPhail consulted the Ministry, the Ontario Heritage Trust, and Prince Township to identify such features. Currently, Unterman McPhail is finalizing a report on the potential impacts to built heritage and cultural heritage landscapes in the project area for submission to the Ministry and has completed the Ministry's *Criteria for Evaluating Potential for Built Heritage Resources and Cultural Heritage Landscapes.*

Thank you again for your time and we will notify you of the submission of the aforementioned cultural heritage report. If you have any questions do not hesitate to ask.

Yours Truly,

Evan Tomek
Environmental Planner
Union Gas Limited
Tel: 519.436.2460 ext 5236904
Email: etomek@uniongas.com

Tomek, Evan

From:	Oscar Alonso <oalonso@tssa.org>
Sent:	June-19-15 4:00 PM
To:	Tomek, Evan; Mike Davis
Cc:	Zora Crnojacki
Subject:	Community Expansion Program. Projects for Walpole Island and Township and Moraviantown.

Dear Mr. Tomek,

Thanks for the information on the Community Expansion Program for these two projects. The documentation submitted is compliant with our regulation and the documentation has been submitted to Mr. Mike Davis, Regional Supervisor, TSSA Inspection.

The construction and or commissioning of the extensions may be subject to an inspection.

Yours truly,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

Tomek, Evan

From:	Oscar Alonso <oalonso@tssa.org>
Sent:	July-06-15 9:27 AM
To:	Tomek, Evan
Cc:	Mike Goldberg; Kourosh Manouchehri; Zora Crnojacki
Subject:	Union Gas Community Expansion Program. Prince Township NG Pipeline Project

Thanks Evan for the information.

We reviewed the Prince Township Natural Gas Pipeline Project, Environmental Protection Plan dated May 2015 and the pipeline specifications.

The polyethylene pipe specs meet the present code requirements. Although the pipeline is scheduled to be constructed in the summer of 2016, when the new CSA Z662-15 is expected to be in effect, we don't see any requirements in the new code that would impose changes in the pipe design, installation or operation.

Regards,

Oscar Alonso, P.Eng.,
Fuels Safety Engineer

Tomek, Evan

From: Tomek, Evan
Sent: August-14-15 7:39 AM
To: 'Becker, Megan (MNRF)'
Subject: RE: Prince Township natural Gas Pipeline Project - Environmental Protection Plan

Hi Megan,

Thank you for your review and comments regarding the Prince Township Natural Gas Pipeline Project Environmental Protection Plan.
Please see my responses to your questions below in red.

If you have any questions don't hesitate to ask.

Thanks,

Evan Tomek, BES
Environmental Planner *on behalf of*
Union Gas Limited | A Spectra Energy Company
745 Richmond Street | Chatham, ON N7M 5J5
Tel: 519.436.2460 ext 5236904
Cell: 226.229.9598
email: etomek@spectraenergy.com

From: Becker, Megan (MNRF) [mailto:Megan.Becker@ontario.ca]
Sent: August-05-15 4:25 PM
To: Tomek, Evan
Subject: Prince Township natural Gas Pipeline Project - Environmental Protection Plan

Hi Evan,

Thank you for your correspondence, dated June 1, 2015, providing the Ministry of Natural Resources and Forestry (MNRF) with an opportunity to review the Environmental Protection Plan report for the Prince Township Natural Gase Pipeline Project. The Ministry has reviewed the report to determine potential impact to Crown land and/or Crown resources as well as to assess whether or not MNRF permits and/or approvals are required for the proposed project. The following comments are based on the review:

1. Please identify the Environmental Assessment Act (EA Act) coverage in relation to the project and the process to be followed. Also, clearly demonstrate any requirements under the EA Act that will apply to all components of the project. This information allows the Ministry to determine the applicability of MNRF's Resources Stewardship and Facility Development Class Environment Assessment.

   - Union's Community Expansion Program is a direct response to the Ontario Energy Board's (OEB) initiative to address the Ontario government's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas. The Prince Township Natural Gas Pipeline Project will be subject to the Ontario Energy Board Act and approval from the OEB is required before the project can proceed. Union Gas has applied to the OEB for a 'leave to construct' pursuant to section 90(1) of the Ontario Energy Board Act. As part of the application, an Environmental Protection Plan (EPP) has been completed to meet the intent of the Ontario Energy Board Environmental Guidelines for the Location Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 6th Edition 2011. Currently the EPP is being reviewed by the Ontario Pipeline Coordinating Committee (OPCC). The OPCC is chaired by a staff member of the OEB and currently includes representation from the following ministries and agencies: Technical Standards and Safety Authority, Ministry of Environment and Climate Change, Ministry of Agriculture, Food and Rural Affairs, Ministry of Tourism, Culture and Sport, Ministry of Municipal Affairs and Housing, Ministry of Natural Resources and Forestry, and the Ministry of Transportation. This review also includes the local conservation authority, municipalities, landowners and other interested parties. All comments received from the OPCC review will be shared with the OEB as part of the approval process.

2. A work permit may be required to conduct work on Crown land and water crossings. In order for the Ministry to determine whether or not a work permit is required further information regarding the location of any Crown land and water crossing within the project area is required. Further information on work permits and application forms can be found on the Ontario website at the following link: http://www.ontario.ca/rural-and-north/crown-land-work-permits

   - At this time all work is proposed within in the road allowance. Union or its Consultant will be in contact to discuss permit requirements.

3. If tree clearing is required, it is recommend that the qualified ornithologist obtained to assess the project area contact MNRF District office for values information on the area and consult with MNRF's management biologists prior to conducting surveys.

   - Noted. Thank you.

   Please keep in mind, that birds are not the only species at utilize trees. Bats utilize standing trees as maternity roosting sites between April 1st and August 31st. As various bat species have recently been listed as endangered under the *Endangered Species Act*, 2007 it is recommended that you contact the MNRF District office should tree clearing be scheduled for the project to discuss any requirements and/or mitigation options for the proposed works.

   - Noted. Thank you. Also, a qualified terrestrial biologist has completed a review of the Natural Heritage Information Centre database that did not reveal any records of at risk bat species in the vicinity of the project. Union or its Consultant will contact MNRF for further discussion.

4. An permit under the *Endangered Species Act, 2007 (ESA)* may be required for the proposed work in there will be impacts to any species at risk and/or their habitat. In order for the Ministry to determine whether or not a ESA permit is required further information is required. At your earliest convenience, have the consultant obtained to review and determine the potential for impacts to species at risk for the project contact the MNRF district office to acquire known values information as well as to discuss and confirm all *Endangered Species Act, 2007* requirements for the proposed work. Please keep in mind that the *Endangered Species Act, 2007* applies on both Crown and private lands. For information on how species at risk are protected, please refer to www.ontario.ca/speciesatrisk .

   - Noted. Thank you.

Please do not hesitate to contact me throughout the project planning process to discuss the permit and approvals that may be required to conduct the proposed work.. Also, should you have any questions regarding the above information, feel free to contact me.

Regards,
Megan

Megan Becker | A/District Planner | Ministry of Natural Resources and Forestry | Sault Ste. Marie District

64 Church Street | Sault Ste. Marie, Ontario P6A 3H3|

(705) 941-5127| (705) 9496450 | megan.becker@ontario.ca |

In order for us to serve you better, please call ahead to make an appointment.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Exhibit A, Tab 2, Section A, B, C, D and E

Union has proposed five construction projects in the different communities.

a) Which communities require easement from private landowners, crown corporations or other entities?

b) Please provide the status and prospects of Union's negotiations with the concerned parties?

Response:

a) Land rights for pipeline easements or stations are required for the Milverton and Kettle and Stony Point First Nations/Lambton Shores Projects.

b) Union has had initial discussions with the directly affected landowners who have not identified any concerns with granting Union the necessary land rights to complete construction of the Projects. Land rights will only be finalized following Board approval of the Projects.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Please comment on the attached draft conditions of approval that are proposed by OEB staff.

Please note that these conditions are draft version and may be subject to additions or changes by the OEB.

Leave to Construct Conditions of Approval
Application under Sections 90 of the OEB Act

Union Gas Limited

EB-2015-0179

1. Union Gas Limited (Union) shall construct the facilities and restore the land in accordance with the Board's Decision and Order in EB-2015-0179 and these Conditions of Approval.

2. (a) Authorization for leave to construct shall terminate 12 months after the decision is issued, unless construction has commenced prior to that date.

   (b) Union shall give the Board notice in writing:

   i. of the commencement of construction, at least ten days prior to the date construction commences;
   ii. of the planned in-service date, at least ten days prior to the date the facilities go into service;
   iii. of the date on which construction was completed, no later than 10 days following the completion of construction; and
   iv. of the in-service date, no later than 10 days after the facilities go into service.

3. Union shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee review.

4. Union shall advise the Board of any proposed change to Board-approved construction or restoration procedures. Except in an emergency, Union shall not make any such change without prior notice to and written approval of the Board. In the event of an emergency, the Board shall be informed immediately after the fact.

5. Both during and after construction, Union shall monitor the impacts of construction, and shall file with the Board one paper copy and one electronic (searchable PDF) version of each of the following reports:

    a) a post construction report, within three months of the in-service date, which shall:

        i. provide a certification, by a senior executive of the company, of Union's adherence to Condition 1;
        ii. describe any impacts and outstanding concerns identified during construction;
        iii. describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction;
        iv. include a log of all complaints received by Union, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions; and
        v. provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project.

    b) a final monitoring report, no later than fifteen months after the in-service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:

        i. provide a certification, by a senior executive of the company, of Union's adherence to Condition 3;
        ii. describe the condition of any rehabilitated land;
        iii. describe the effectiveness of any actions taken to prevent or mitigate any identified impacts of construction;
        iv. include the results of analyses and monitoring programs and any recommendations arising therefrom; and
        v. include a log of all complaints received by Union, including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions.

Response:

a) Union can accept the draft conditions of approval.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 1

The evidence states that, "The Ontario government's desire to expand natural gas distribution systems, which will increase natural gas use, is inconsistent with their recently announced intent to implement a cap and trade program whose objective is to significantly reduce the use of natural gas." Please explain how the implementation of a cap and trade program would impact Union's proposals as set out in this application. Has Union done any sensitivity analyses regarding its proposals, assuming the implementation of an Ontario cap and trade program? If so, please provide that analysis.

Response:

Union has not conducted a sensitivity analysis of its proposal assuming the implementation of an Ontario cap and trade program. The Province has not finalized a framework and is currently undertaking consultations on its development. Any framework that ultimately causes a dramatic reduction in the use of natural gas in the province will have investment and depreciation impacts on Union that extend far beyond the Community Expansion Proposal. However, Union continues to believe that the Government will find an appropriate balance between the economic, environmental and social needs of the Province that would support further infrastructure expansion. If they do not, Union may not use the regulatory flexibility granted through this proposal.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, pp. 3- 4

The evidence asserts at page 3 that the parameters of Union's proposals have been set to limit the rate impacts on existing customers to a maximum approximating $2 per month ($24 per year) over the multi-year expansion program; the evidence further asserts at page 4 that the bill impacts across existing residential customers will be less then $4 per year. Please reconcile these two assertions.

Response:

Approval to proceed with the first five[1] Projects filed in Exhibit A, Tab 2, is an initial step in a broader program. Union has filed the potential ratepayer cost impacts in order to inform the Board of the implications of this broader program.

The "less than $4" bill impact is in reference to the estimated impact of proceeding with all 30 Projects for a typical existing residential customer after considering the impact on rates as well as the offsetting TES/ITE deferral[2]. When the TES/ITE period expires, there will no longer be a revenue offset, so the bill impact will increase for the same customer by the amount of the TES/ITE deferral credits.

Union has set a maximum rate impact of $24 per year to allow for additional future Projects which may become feasible either through:

- Improved circumstances for other Projects listed in Exhibit A, Tab 1, Appendix D (for example additional customers or reduced costs),
- New Projects that Union was unaware of at the time of filing Exhibit A, Tab 1, Appendix D that may be feasible, or
- Funding from the Province of Ontario. At this time, details on the provincial funding[3] are not available, so consequently Union could not predict how much of that funding might support additional Projects undertaken by Union.

A maximum rate impact of $24 per year would provide reasonable capacity for other Projects to occur. Union will seek Board approval for the recovery associated with the net revenue requirements for the projects as noted at Exhibit B.Staff.4 a).

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.
[2] The Community Expansion Contribution Deferral Account ("CECDA") referenced at Exhibit A, Tab 1, Table 1, p. 33.
[3] Reference: Exhibit A, Tab 1, p. 43

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 4

Union's evidence is that under its proposal it could complete approximately 30 projects to provide service to approximately 20,000 homes and businesses in 34 communities. Is Union seeking approval to pursue those 30 projects through this application or is it only seeking approval of the five proposed projects at this time? Please explain the specific relief Union is seeking through its application. For projects beyond the five included in the application would Union be filing further applications?

Response:

Union is seeking approval to proceed with the 5[1] projects outlined in Exhibit A, Tab 2, along with recovery of the resulting revenue deficiency from those projects. Union is not seeking approval to proceed with any other projects outlined in Exhibit A, Tab 1, Appendix D. In addition to the 5 projects, Union is seeking approval to apply new funding mechanisms and feasibility criteria as outlined in Exhibit A, Tab 1, to future Community Expansion projects.

For any additional Projects, Union will conduct detailed costing and market analysis to determine project feasibility, and apply to the Board for approval for recovery of the resulting revenue deficiency, and Leave-to-Construct where required, for each project.

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 5

The evidence discusses how "parties" were invited by the Board to file proposals designed to support its "*expansion of natural gas distribution*" initiative. Does Union understand "parties" to potentially include entities that are not currently providing natural gas distribution service in Ontario? If not, why not? With respect to the proposals discussed in this application are there any projects that Union believes only it, based on its existing infrastructure and/or the existing regulatory framework (including for example the scope of Union's licenses, approvals, etc.) can undertake? If so please provide details underpinning that apparent exclusivity. With respect to the total projected costs of approximately $150 million for the identified 30 projects, please provide an analysis that splits that total cost between a) costs that would incurred by Union with respect to its existing assets in order to enable connection of new communities, regardless of which party ultimately undertakes the actual expansion, and b) the costs of building the required new infrastructure. Put another way, if a party other than Union were to propose an identical plan with identical forecast costs, how much of the proposed $150 million would be spent on existing Union assets to enable connection (assuming that the proposal does not bypass Union's existing system) and how much would be spent to create the new system?

Response:

Union believes that the existing gas distributors in Ontario are best positioned to expand natural gas infrastructure in the province at the lowest cost to consumers.

However, Union understands "parties" to include those with the appropriate financial and technical expertise, as noted in the Board's invitation for proposals[1]. As such, "parties" could include entities that are currently not providing natural gas service in Ontario. Union also notes that the Minister of Energy's letter[2] to the Board dated February 17, 2015 indicated a commitment to work with gas distributors and municipalities to expand natural gas infrastructure. It does not indicate a commitment to work with entities that are not gas distributors.

Union currently has franchise agreements and Certificates of Public Convenience and Necessity for approximately 80% of the 30 potential Projects identified. However, a municipality can have franchise agreements with several gas distributors. For example, the area near the border of Union's service area and that of NRG is in the same municipality and as a result the local

[1] Exhibit A, Tab 1, Appendix A, page 2
[2] Exhibit A, Tab 1, Appendix A, page 1

municipality has franchise agreements with both utilities. In contrast, the Certificate of Public Convenience and Necessity provides for gas LDC exclusivity, but Union is aware that the certificates could be amended through an application to the Board.

Consequently, Union does not believe that there are any projects that only it could undertake. However, Union continues to believe existing gas LDC's are best positioned to complete these projects because they already have the necessary support infrastructure in place, have the necessary experience, skills and knowledge, have proven long term histories as effective, reliable and safe distributors, and have the best opportunity to deliver the projects at the lowest long term costs for Ontario consumers through economics of scale. Union has over the longer term proven its capability to effectively respond to emergencies, leveraging skilled staff from across the province to provide local emergency response resources when necessary. Union's response to the 2014 tornado that touched down in downtown Goderich provides an example of this capability. Union has a strong reputation for safety and reliability of supply that a new entrant is unlikely to match.

Union does not have an accurate cost figure of Union assets to connect other LDC's that might serve these communities. There are several projects that would require reinforcement or result in advancement of future reinforcement, but the high level costing analysis did not split the cost up appropriately for this type of analysis.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 5

The evidence states that Union's Community Expansion proposal supports the provincial policy goal of providing customers in the underserved communities with more energy choices. Beyond the direct customers that will have access to natural gas service under Union's program, who else will benefit from the program, and in what way will they benefit?

Response:

A number of parties will benefit beyond the consumers in the new communities who connect to the natural gas system.

Within those communities, even those that do not directly connect will benefit through the increased spending resulting from the annual energy savings of those who connect. This will boost economic activity in the community. Additional jobs may result from the conversion or replacement of heating systems, water heaters, and other natural gas appliances. Aside from this, the broader community can further benefit by being more competitive in attracting new businesses, or enabling growth in existing businesses, since the barrier of not having access to the lowest cost energy choice, natural gas, is removed.

Union's proposal will also benefit ratepayers over the longer term. There are likely to be future attachments to the new systems installed as part of the projects, beyond the 10 year customer attachment forecast period, that are excluded from the economic feasibility analysis. Assuming current price comparisons to other forms of energy remain similar to today, it is likely that attachment rates will climb from around 45% to close to 90%[1] of the homes and businesses adjacent to the new systems in the 11 to 25 year period after the project is put into service. These future attachments will be much more profitable (P.I.'s well over 1.0) as they will not likely require any main to be installed; they will only require the service line and meter set-up.

Existing ratepayers will benefit from these profitable future attachments as they generate incremental revenue. Existing ratepayers will also benefit from economies of scale as the fixed costs of operating the gas distribution utility, which are included in the pre-existing rates for existing ratepayers, are spread over a larger customer base.

[1] Union's current penetration of single family homes that are adjacent to the natural gas system is 90% based on Union Gas 2011 market Share study, provided at Exhibit B.SEC.9, Attachment 1, p.3

Evidence of this future benefit is the fact that Unions Rolling Project Portfolio ("RPP"), as shown at Exhibit A, Tab 1, p. 37, Table C, indicates a most recent annual average P.I. of 1.48[2], and an average positive NPV of $14.6 million each year. This trend of positive NPV's has been well established over the past decade. This trend suggests that new customers have actually been subsidizing existing ratepayers, through a period where very few Community Expansion Projects occurred.

Existing ratepayers will also benefit from economies of scale as the fixed costs of operating the gas distribution utility, which are included in the rates for existing ratepayers, are spread over a larger customer base and increased throughput. For example, Union already has offices located across the franchise area in which additional staff to service Community Expansion areas can be located. Union already has two centralized call centres and four centralized billing centres with all the required technologies to provide service. Union already has trained and skilled field personnel who can provide required services, including emergency response, to many of the potential project areas, along with a state-of-the-art training facility for those resources.

In addition to the above, there are provincial and national economic benefits of expanding natural gas infrastructure. The Canadian Gas Association recently released a report completed by ICF that quantifies the macro economic benefits of expansion. Please see Attachment 1 for ICF's Report[3]. The report, although national in scale, indicates that an investment of $1.3 billion in natural gas expansion to new communities will generate $1.7 billion in direct, indirect and induced Canadian GDP benefits[4]. Based on these figures, Union's potential investment of $150 million for 30 Projects would generate Canadian GDP benefits of almost $200 million.[5]

Expansion of natural gas infrastructure will also lead to significant environmental benefits. The ICF study referenced above indicates that the infrastructure investment would lead to "a decrease in annual GHG emissions equivalent to over 75,000 tonnes of CO2 per year, equivalent to removing approximately 16,000 passenger vehicles from the road. Over the 25 year study period; this represents a cumulative reduction in CO2 of 1.88 million tonnes, equivalent to the annual CO2 production of almost 400,000 passenger vehicles."[6] Based on these figures, Union's potential investment of $150 million would result in greenhouse gas emission reductions of almost 7,700 tonnes of CO2 equivalent each year.[7]

---

[2] A 3 year average from RPP results for 2012, 2013, and 2014.
[3] ICF International Report -Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers; http://www.cga.ca/publications/.
[4] ICF International Report -Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers, page iii.
[5] Based on: 150/1307.3 x 1,730 (all figures in millions), sourced from above noted ICF report, Exhibit 8 and Exhibit 17.
[6] ICF International Report -Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers, page ii.
[7] Based on 150/778.8 x 39,827 sourced from above noted ICF report, Exhibit 8 and Exhibit 21.

Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers

November 2015

Submitted by:
ICF International
300-222 Somerset Street West
Ottawa, Ontario K2P 2G3

Submitted to:
Canadian Gas Association

ICF Contact
Harry Vidas
703-218-2745

Other ICF Contributors
Peter Narbaitz
Bansari Saha
Katie Segal

Executive Summary

Project Background and Approach

In many parts of Canada, the natural gas distribution utility industry is examining measures that would support pipeline connection opportunities to new communities. Natural gas would be used as a replacement fuel for homes, businesses, and industrial facilities. These communities currently rely on higher cost, and in many cases higher emitting, fuels for heat and power. Across Canada, the average annual cost of heating with electricity, propane, and heating oil are two to three times higher than with natural gas. As a result, there exists significant potential cost and emissions benefits to homeowners, businesses, and industries that gain access to the natural gas pipeline system.

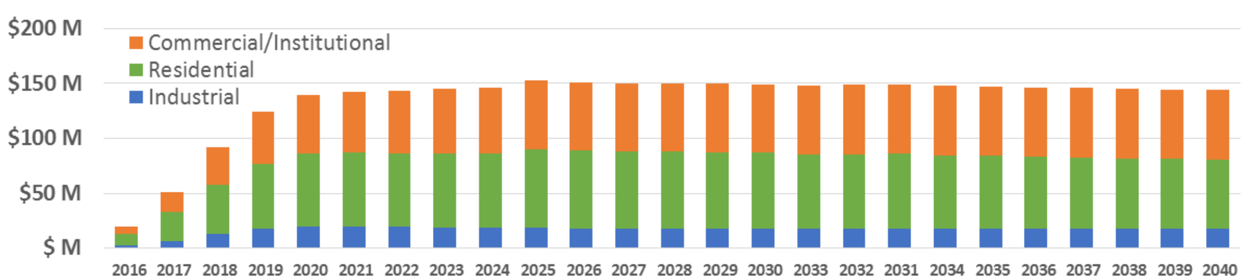
To properly consider the merits of expanding natural gas distribution pipelines, economic regulators, governments, and other decision makers need a clear understanding of the costs and benefits for new gas customers, as well as the impacts on the broader Canadian economy and environment. This study assesses these costs and benefits, and presents key metrics that demonstrate the net impacts.

ICF worked with the CGA and Canadian distribution utilities to define the scope of expansions and type of customers that would be reached, ultimately settling on projects representing an investment of CDN$ 1.3 billion, to install roughly 6,000 km of pipeline and service lines. Key parameters such as fuel cost savings and equipment costs were then analysed to assess the viability of such projects from the customer's perspective and to serve as inputs to the economic model. The economic modeling then assessed the effects on Canadian GDP, jobs, and government revenues from such projects. Finally, analysis was carried out to assess the consumer impacts of $15 and $100 per tonne CO2 equivalent prices.

Study Results

Exhibit ES 1 presents the annual customer fuel cost savings over the study period, broken down by customer type. Savings ramp up between 2016 and 2020, when the bulk of new customers considered in this study become connected to gas supplies, reaching around $150 million per year. **The average new residential customer would achieve annual fuel cost savings of $1,619 per year, or more than $25,000 over the life of the gas heating equipment.**

Exhibit ES 1 Annual Fuel Cost Savings of New Natural Gas Customers (2015$ Million)[1]



Overall, these conversions represent a decrease in annual emissions equivalent to over 75,000 tonnes of CO2 per year, equivalent to removing approximately 16,000 passenger vehicles from the road.[2] **Over the 25 year study period, this represents a cumulative reduction in CO2 of 1.88 million tonnes, equivalent to the annual CO2 production of almost 400,000 passenger vehicles.**

[1] Values in this chart represent the annual net fuel cost savings, in real 2015 Canadian dollars, for all new natural gas customers. This takes into account delivered fuel costs and relative equipment efficiency. These savings do not include costs to buy new gas burning equipment, costs for CO2 emissions, or all the costs for distribution system expansions.
[2] United States Environmental Protection Agency, Greenhouse Gas Equivalencies Calculator, 2014.

The impact of a price on CO_2 emissions is strongly dependent on the fuel-mix being displaced by natural gas. The business case for replacing heating oil, propane, and heavy oil with gas is better when a tax is levied for CO_2 emissions, whereas the business case is not as strong when converting from electricity (in many jurisdictions) or biomass.

In addition to the annual fuel cost savings, this study calculates[3] all of the incremental customer costs (including equipment upgrades to burn natural gas and customer contributions to system expansion).

Exhibit ES 2 shows that for the **consumers in this study there are over $1.4 billion in total customer benefits on a present value basis from gaining access to natural gas. The largest savings are in the residential sector, at $631 million[3], followed by the commercial/institutional and industrial sectors, at $593 and $213 million[3], respectively.**

Exhibit ES 2 Net Present Value of Total Net Savings for New Customers (2015$ Million)[4]

Residential	Commercial / Institutional	Industrial	Canada Total
631	**593**	**213**	**1,437**

The total cost of the investment to connect the new communities in this report is estimated to be $1.3 billion. To unlock the savings potential, it is estimated that utilities would require $486 million[3] of incremental funding support (either through revised community connection economic test parameters set out by provincial regulators or through government programs). **Combining this distributor funding shortfall of $486 million[3] with the customer savings of $1.4 billion[3], shows that there remains a net benefit of $950 million[3] for society as a whole.**

The benefits of investing in pipeline expansion to new consumers extend beyond just the new customers (lower energy costs) and emission levels (lower CO_2 production). There are also significant impacts for Canada's GDP, employment, and government taxes and revenues.

Exhibit ES 3 summarizes the economic modeling results, which detail the broader macro-economic implications of investing in new pipelines. The primary drivers of economic impacts are the re-spending of customer fuel cost savings[5], along with utility pipeline infrastructure spending. **It is expected that over a 25 year period, these expansion projects would add $1.7 billion to Canada's GDP, contribute support of 31,500 net job-years, increase government revenues by over $600 million, and reduce CO_2 emissions by nearly 1.9 million tonnes.**

Exhibit ES 3 Summary of Economic Impacts from Pipeline Distribution Expansion over Study Period

Type of Economic Benefit	Direct & Indirect Impacts	Induced Impacts	Total Impacts (2016-2040)
GDP ($Million)	1,104	626	**1,730**
Employment (Job-years)	23,732	7,777	**31,509**
Government Taxes and Revenues ($Million)	395	224	**619**

[3] On a Net Present Value basis.
[4] Values in this table represent the Net Present Value of the conversions, in real 2015 Canadian dollars, for new natural gas customers. This takes into account delivered fuel costs, some customer contributions for distributor system expansion costs, and additional costs to buy and install new gas burning equipment. This NPV does not include costs for CO_2 emissions or costs for distribution system expansions beyond those recovered from gas customers.
[5] As reduced by the distributor expansion cost shortfall. In accounting for this shortfall, the economic impact modeling was agnostic as to the source of capital (gas rate payers, the general tax base, etc.) to support the pipeline expansions. For the purposes of estimating net macro-economic impacts, the shortfall is covered ('paid for') through reducing the amount of consumer spending.

Table of Contents

Executive Summary .... **ii**

1 Overview of Natural Gas in Canada **1**

Introduction 1
Natural Gas Pipelines and Storage 3
Natural Gas Price Outlook 4

2 Project Background **5**

3 Project Approach **7**

4 Study Results **8**

Customer Impacts 8
Macro-Economic Impacts 14
CO2 Emission Price Sensitivity 17

Appendix A Methodology and Assumptions **A-1**

Distributor Surveys A-1
Customer Impact Calculations A-1
IMPLAN Scenarios A-6
Macro-Economic Modeling A-6
General Assumptions A-9
IMPLAN Background A-10

Appendix B Provincial Fuel Cost Savings **B-1**

List of Exhibits

Exhibit 1 Canada's Natural Gas Resource Base 1
Exhibit 2 Geographic Coverage of the Natural Gas Distribution Sector across Canada 2
Exhibit 3 Natural Gas Distribution System Details 3
Exhibit 4 Average Delivered Energy Costs for Canadian Residential Customers 4
Exhibit 5 Comparison of Heating Fuel Costs and Market Share 5
Exhibit 6 Project Approach and Stages 7
Exhibit 7 Historical Level of Investment in the Natural Gas Sector 9
Exhibit 8 Distributor Expenditures for Natural Gas Expansion Projects, by Year 9
Exhibit 9 Number of New Natural Gas Customers, by Province (2016-2025) 10
Exhibit 10 Number of New Natural Gas Customers, by Fuel Type (2016-2025) 10
Exhibit 11 Annual Natural Gas Consumption from New Customers (GJ p.a. in 2025) 11
Exhibit 12 Annual Fuel Cost Savings of New Customers (2015 $Million) 11
Exhibit 13 Average Annual Fuel Cost Savings, by Province (2016-2040) 12
Exhibit 14 Average Annual Fuel Cost Savings, by Fuel Type (2016-2040) 12
Exhibit 15 Customer Expenditures for New Natural Gas Equipment 13
Exhibit 16 Net Present Value of Total Net Savings for New Customers 13
Exhibit 17 Summary of Economic Impacts from Pipeline Distribution Expansion 14
Exhibit 18 Annual Increase in Canadian Gross Domestic Product 15
Exhibit 19 Annual Increase in Canadian Employment 16
Exhibit 20 Annual Increase in Government Taxes and Revenues 16
Exhibit 21 Net Annual GHG Emission Reductions, by Province 17
Exhibit 22 Net Annual GHG Emission Reductions, by Fuel Type 18
Exhibit 23 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040) 18
Exhibit 24 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040) 19
Exhibit 25 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040) 19
Exhibit 26 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040) 20
Exhibit 27 Low CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective 20
Exhibit 28 High CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective 21
Exhibit 29 GHG Emission Factors A-5
Exhibit 30 Ontario - Annual Fuel Cost Savings of New Customers ($ Million) B-1
Exhibit 31 British Columbia - Annual Fuel Cost Savings of New Customers ($ Million) B-1
Exhibit 32 Manitoba - Annual Fuel Cost Savings of New Customers ($ Million) B-2
Exhibit 33 Quebec - Annual Fuel Cost Savings of New Customers ($ Million) B-2

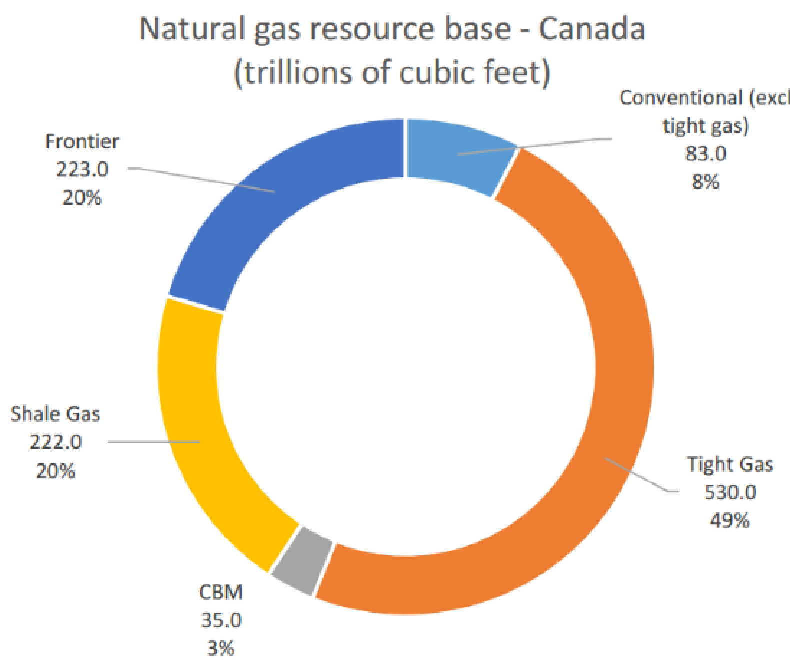
1 Overview of Natural Gas in Canada

Introduction

The integrated North American natural gas market has undergone a dramatic supply side change in the past two decades. In the 1990s and early 2000s, natural gas production was flat to declining while consumption continued to trend upward in both Canada and the U.S. As a result, periods of high and volatile commodity prices were common.

This period of high prices and volatility began to come to a close around 2007, as producers began to economically produce large quantities of tight gas and shale gas by employing technological developments related to horizontal drilling and multi-stage hydraulic fracturing. These new techniques unlocked significant new supplies of natural gas across North America. In Canada alone, the natural gas resource base has doubled since the year 2000 and is estimated at over 1,000 trillion cubic feet,[6] equal to 200 years of supply at current production levels.[7] The impact of tight gas and shale gas is highlighted in Exhibit 1, which shows that they represent almost 70% of Canada's natural gas resource base.

Exhibit 1 Canada's Natural Gas Resource Base



Source: National Energy Board, US Geological Survey

Additionally, the ongoing development of new U.S. supply capacity, which can be delivered at affordable prices, particularly from the Marcellus Shale and Utica Shale plays in the U.S. northeast, is putting pressure on traditional supplies of natural gas delivered from Western Canada to markets in Eastern Canada.

Forecasts suggest that large quantities of low cost shale gas will be available to the market well into the future and, as a result, will have a moderating impact on the commodity price of natural gas. The

[6] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/05/Chart-9-Natural-Gas-Resources-Canada.pdf
[7] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/05/Chart-7-Natural-Gas-Production.pdf

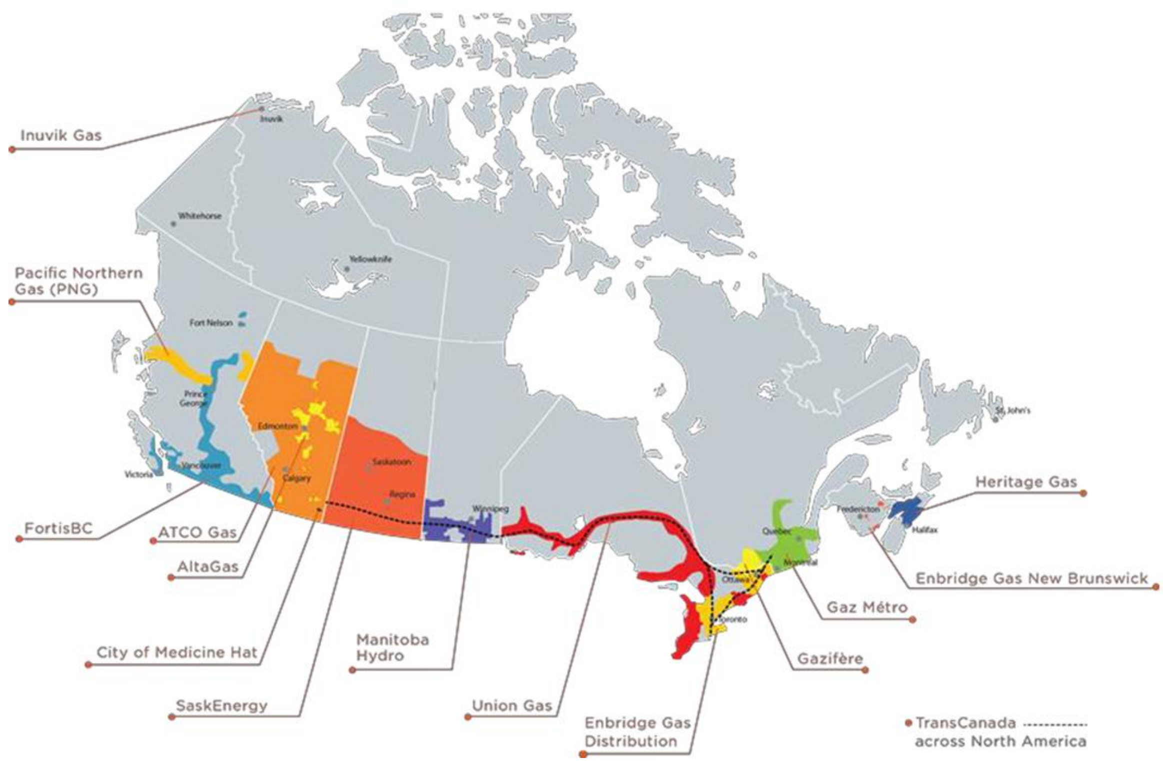
National Energy Board (NEB) forecasts that Canadian natural gas prices will remain below $USD 6.48 per million British thermal units (MMBtu) to 2035.[8] For comparison, the price for natural gas in Canada at AECO in Alberta, which is the primary pricing point in Canada, averaged around $USD 5/MMBtu between January 2001 and June 2015.[9]

Complementing expectations for stable prices is the growing recognition of natural gas' environmental benefits. On a CO2 equivalent basis, natural gas emissions are lower than other fossil fuels. Further, natural gas produces very little criteria air contaminants such as nitrous oxides, sulfur dioxides, and other smog-producing pollutants.

On its price and environmental merits, the use of natural gas continues to advance with overall domestic demand in Canada, increasing by close to 11 percent since the 2009 recession, mainly driven by power generation and oil sands markets. Significant new markets for natural gas exist in Canada, including new power generation (via highly efficient combined heat and power), on- and off-road transportation markets, northern communities and mines (using trucked liquefied natural gas as a fuel source), and through deployment of new gas pipelines to rural Canadian communities not served by natural gas.

Increased demand for natural gas has led to growth in Canada's natural gas distribution system, which had expanded to just over 450,000 kilometres of pipeline by the end of 2014. The geographic areas served by Canada's natural gas distribution companies are shown in Exhibit 2. The provinces of Newfoundland and Prince Edward Island do not have pipeline natural gas distribution infrastructure. In addition, outside of a small distribution network in Inuvik, none of the territories have pipeline natural gas distribution infrastructure.

Exhibit 2 Geographic Coverage of the Natural Gas Distribution Sector across Canada



[8] National Energy Board, Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035, 2013.
[9] Based on historical data tracked in ICF's Gas Market Model.

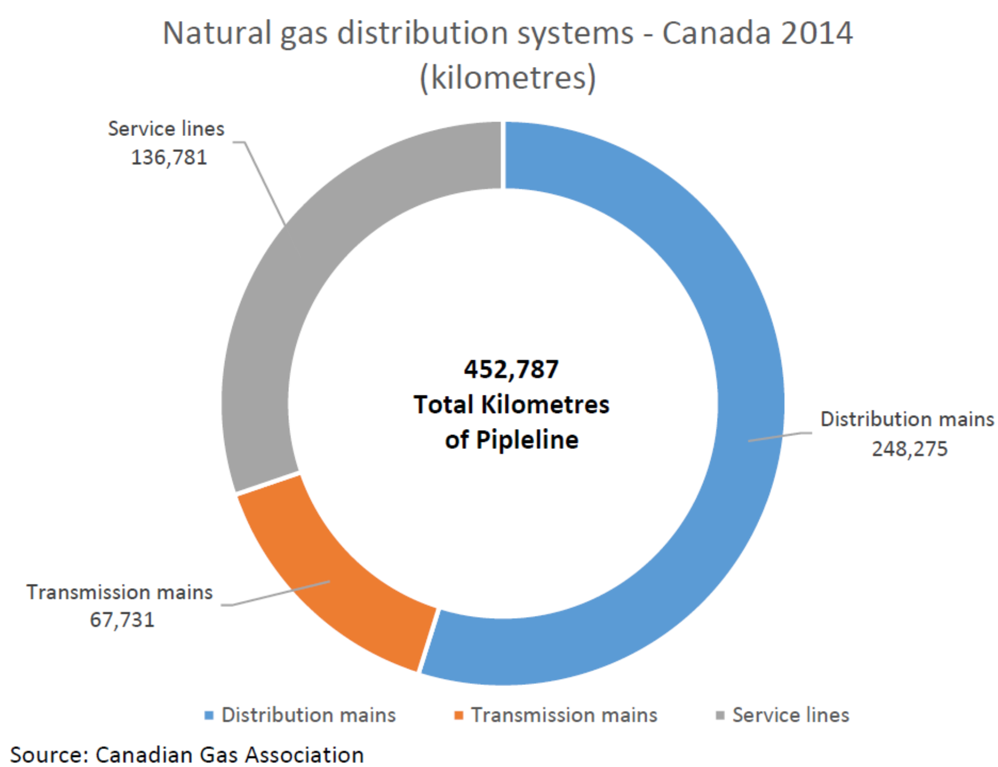
The natural gas distribution sector invested more than $2.6 billion[10] in new and upgraded infrastructure in 2014[11], and provided employment for just over 15,500 full-time-equivalent persons.[12] The natural gas distribution sector GDP continues to increase, rising to just over $5.2 billion ($2007 base year).[13]

Natural Gas Pipelines and Storage

Canada's natural gas pipeline and storage infrastructure is vast and robust. The network of pipelines in 2014 totalled 452,000 kilometres.[14] As shown in Exhibit 3, more than half of this total are distribution main lines that bring natural gas into neighbourhoods and along city streets. An additional 136,000 kilometres are service lines that carry gas directly to homes and businesses of the final customer. The remaining infrastructure consists of large transmission lines that move natural gas from production areas to local markets.

Natural gas storage capacity in Canada continues to expand with over 820 billion cubic feet of capacity available. Low prices and average demand has left storage facilities relatively full in recent years. Continued additional supply from new shale basins is supporting this trend. Storage provides flexibility to respond to changes in demand and allows stockpiling of supply for peak winter demand periods. Canada has approximately 60 days of natural gas demand available in its storage reservoirs at the beginning of every heating season. This storage assists in moderating prices for consumers.

Exhibit 3 Natural Gas Distribution System Details



[10] All dollar amounts in this report are expressed in Canadian dollars unless stated otherwise.
[11] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/06/Chart-15-Natural-Gas-Investment.pdf
[12] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/06/Chart-13-Natural-Gas-Employment.pdf
[13] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/06/Chart-14-Natural-Gas-GDP.pdf
[14] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/06/Chart-16-Natural-Gas-Distribution-System.pdf

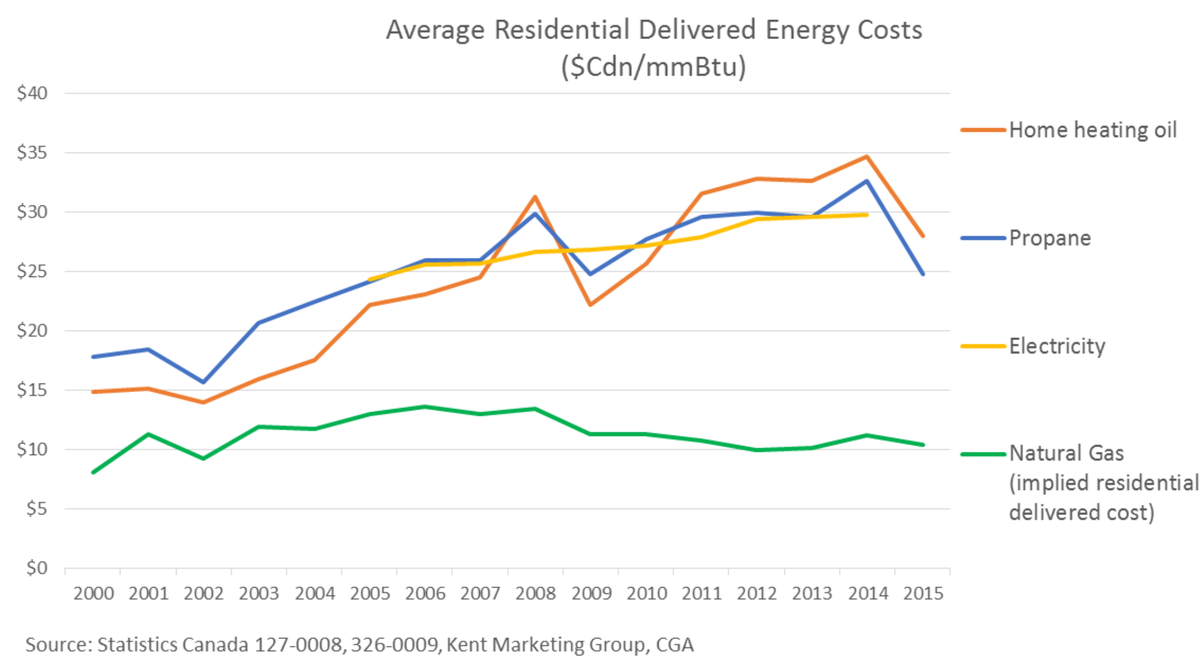
Natural Gas Price Outlook

Natural gas enjoys a wide price advantage over other energy commodities. The extensive North American natural gas supply base continues to put downward pressure on natural gas prices in Canada and in the U.S. In addition, the emergence of significant U.S. imports into the major Eastern Canadian market area has reduced demand for Canadian natural gas, which has resulted in even lower domestic natural gas pricing.

In a recent Short Term Energy Outlook, the U.S. Energy Information Administration (EIA) projects Henry Hub (the major pricing point for natural gas in the United States) will average $USD 2.98/MMBtu in 2015 and $USD 3.31/MMBtu in 2016.[15] A longer term forecast from the EIA contains scenarios where 2040 Henry Hub prices range from $USD 4.38/MMBtu to $USD 10.63/MMBtu, with a 2040 reference case price of $USD 7.85/MMBtu.[16]

While natural gas commodity price forecasts contain significant variability, it is important to keep the range of these fluctuations in perspective. Exhibit 4 compares historical average delivered energy costs for Canadian residential customers, highlighting the significant gap in costs between fuels, and showing that even rising natural gas prices should maintain a significant cost advantage over the other fuels.[17]

Exhibit 4 Average Delivered Energy Costs for Canadian Residential Customers



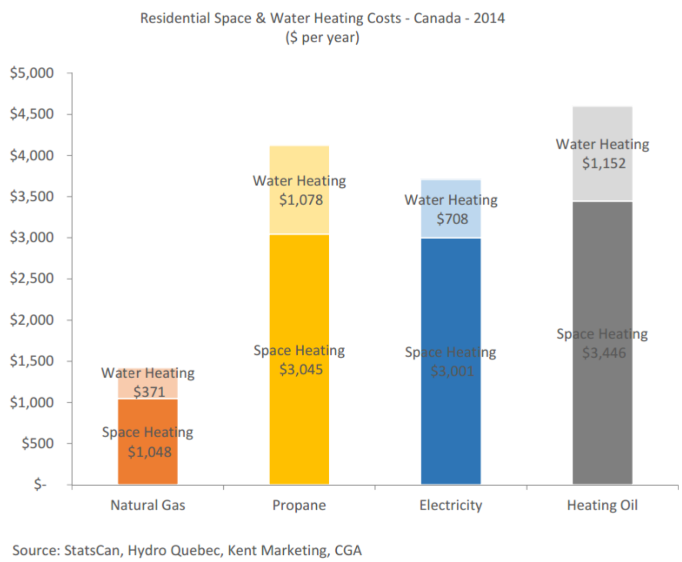
[15] U.S. Energy Information Administration, Short-Term Energy Outlook, August 2015. http://www.eia.gov/forecasts/steo/report/natgas.cfm
[16] U.S. Energy Information Administration, Annual Energy Outlook 2015 with projections to 2040, April 2015. http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf
[17] CGA, personal communication, November 17, 2015.

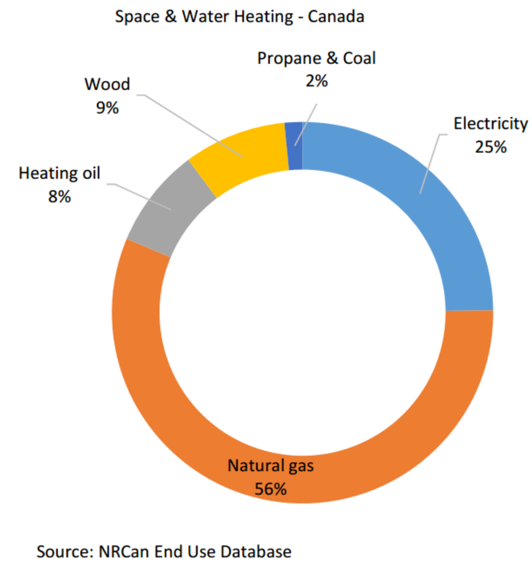
2 Project Background

In many parts of Canada, the natural gas distribution utility industry is examining measures that would support pipeline connection opportunities to new communities where natural gas would be used as a replacement fuel for homes, businesses, and industrial facilities, which currently rely on higher cost fuels for heat and power.

Past research from the Canadian Gas Association (CGA) has shown that average Canadian heating costs are significantly lower with natural gas. While fuel costs vary significantly among provinces, on average, annual costs for heating with electricity, propane, and heating oil are two to three times higher than with natural gas. For this reason, 56% of Canada's homes are already heated with natural gas. In terms of other heating fuels, electricity is used by 28% of homes, followed by heating oil (8%), wood (9%), and propane (2%). This data is presented below in Exhibit 5.[18,19]

Exhibit 5 Comparison of Heating Fuel Costs and Market Share





This highlights that there are significant potential benefits to homeowners, businesses, and industries to access the natural gas pipeline system, and that there remains a large portion of Canada without access to natural gas. The map in Exhibit 2 showed the current areas in Canada served by the natural gas pipeline system. Across Canada, there are 6.5 million natural gas meters – each serving a home, business, or industry. It is estimated that 20 million Canadians use natural gas as a fuel source. Therefore, there are approximately 15 million Canadians who rely on alternative fuels for heating.

In addition to fuel cost savings, another potential driver for natural gas adoption is increasing efforts to limit greenhouse gas (GHG) emissions through price-setting regimes on those emissions. The combustion of natural gas produces lower GHG emissions than heating oil, propane, or heavy oil, reducing the impact of any CO2 emission price on the consumer. Conversely, heating with electricity means lower CO2 emissions levels than natural gas,[20] so any CO2 emission price impacts will depend on the customer types being targeted for conversion to natural gas.

[18] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/05/Chart-19-Residential-Heating-Costs.pdf
[19] CGA, 2015. http://www.cga.ca/wp-content/uploads/2015/05/Chart-20-Residential-Heating-Types.pdf
[20] GHG emission factors for electricity vary significantly by province, but on average are lower than natural gas.

To properly consider the merits of expanding natural gas distribution pipelines, economic regulators, governments, and other decision makers need a clear understanding of the costs and benefits for new gas customers, as well as the costs and benefits for the broader Canadian economy. This study assesses these costs and benefits, and presents key metrics that demonstrate the net benefit of providing natural gas distribution pipeline access to new customers.

More specifically, this study provides an understanding of the macro-economic implications and benefits (GDP, jobs, government revenues) of expanding the natural gas distribution pipeline to new communities and industry in Canada. Some of the key areas into which this study provides insight include:

- the economic impacts of a $1.3 billion investment to connect the communities to local distribution company networks;
- the energy cost savings achieved by switching to natural gas from the incumbent energy sources;
- the total (direct, indirect and induced) economic benefits to the Canadian economy in terms of contribution to GDP, support of jobs, and provincial and federal tax revenues; and
- the sensitivity of natural gas pipeline expansion projects to CO2 emission prices.

The primary driver of overall economic benefits is the re-spending of customer fuel cost savings, which is calculated by comparing fuel price forecasts. However, it is important to consider all macro-economic implications, as natural gas conversions will lower domestic consumption of some other fuels, and hence have negative economic impacts in some areas.

Through the findings in this report, the CGA and its member company utilities work to educate and inform stakeholders as to the consumer and broader economic benefits of supporting regulatory flexibility or policy support to achieve greater investment in new natural gas pipeline infrastructure.

While this study shows significant impacts for both new customers and the broader Canadian economy, it is required that either customers (the rate base) or the broader tax base (through government programs), or a combination of both measures, would be required to make the necessary investments to fund pipeline expansion projects. Given that expansion costs are concentrated with the distributors, but the benefits are concentrated with the consumers, the distributors would be required, by regulatory rule, to connect and recover the full costs for such expansions. For most of the communities prohibitive up-front financial contributions would be required from the customers to make the projects feasible. As noted, there are a number of potential business models/solutions to support the capital needs to connect communities, including modification of regulatory economic tests for connecting new customers (e.g., approval of lower profitability index, monthly consumer payback programs to support high pipeline construction and related costs, etc.) or government-backed funding programs (e.g., programs to support transitions from higher cost or higher emitting fuels to natural gas), or a combination of both measures.

In addition to pipeline gas supply expansions, there are a number of off-pipeline mines and communities that could benefit from natural gas as an alternative fuel source. For these more remote regions, the use of compressed or liquefied natural gas (CNG or LNG) could represent a more cost-effective approach. A separate ICF report assessing the benefits from LNG infrastructure expansion for remote communities will be available through the CGA in early 2016. That study will examine the consumer and economic impacts of an investment in new LNG plants and related infrastructure (LNG storage, transport trucks, vaporizers, etc.). For the purposes of the study herein, the focus and scope includes only the results from natural gas distribution pipeline expansions.

3 Project Approach

This section provides an overview of ICF's approach to assessing the benefits to consumers, and the economic impacts on the Canadian economy from natural gas distribution pipeline expansion. A detailed discussion of the project's methodology and key assumptions is provided later, in Appendix A. The three main stages of this project are outlined in Exhibit 6, and are summarized below.

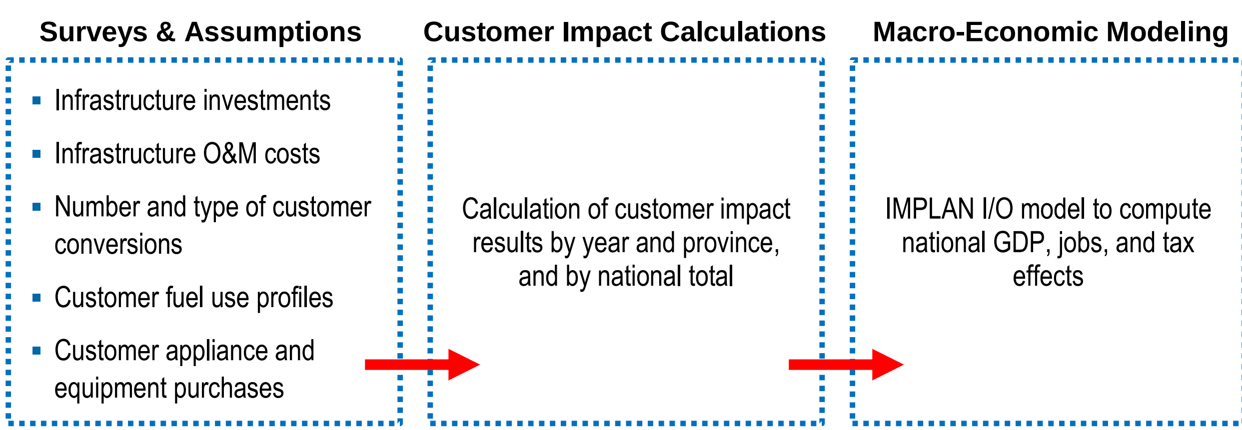
The first stage of the work involved data collection, which included surveys of Canadian natural gas distributors, independent research, and the collection of institutional knowledge from experts at both ICF and the CGA.

The second stage of the project, customer impact calculations, involved an analysis of key parameters that could be used to judge the favourability of pipeline expansion projects. The outputs of this stage provide important metrics on the viability of such projects from the customer's perspective and serve as inputs to the economic model. This stage also assessed the sensitivity of new customer benefits to hypothetical low and high CO2 emission price scenarios.

The third stage of the project focused on economic modeling, and provides additional metrics to assess the impact of distribution pipeline projects on the broader Canadian economy. This stage assesses the effects on GDP, jobs, and government revenues from such projects. This modeling is based on IMPLAN input/output matrices. IMPLAN tracks different types of Canadian economic impacts from expenditures in 103 sectors of the economy. By determining how the expenditures associated with natural gas distribution pipeline expansion align with the categories in IMPLAN, it was possible to establish their impacts.

The IMPLAN model differentiates between spending impacts for the Canadian economy and impacts 'leaked' to imports. All of the results in this study present impacts to the Canadian economy, and have been adjusted to remove the effect on imports.

Exhibit 6 Project Approach and Stages



Appendix A discusses the steps in the study process in more detail, provides information on some key assumptions driving the analysis, and describes the IMPLAN model.

4 Study Results

In this section the results of the customer impact calculations are presented first, followed by the economic modeling results, and then a look at the sensitivity of customer impacts to CO2 emission prices.

The customer impact calculation results showcase the benefits from the consumer's perspective, and include Net Present Value calculations demonstrating that the fuel cost savings will outweigh the requirement for customers to invest in new equipment and appliances. This first set of results also highlights the capital expenditures the natural gas distributors would be required to invest in order connect these customers to pipelines.

The economic modeling results then quantify the benefits these projects would bring to the broader Canadian economy. These results focus on value added (GDP), increased employment, and increased government revenues.

The CO2 emission price sensitivity results first show the expected net changes to GHG emissions from the customers targeted in these expansion projects. Low and high price scenarios then demonstrate how customer fuel cost savings and NPV could be affected by existing or future CO2 emission prices.

Customer Impacts

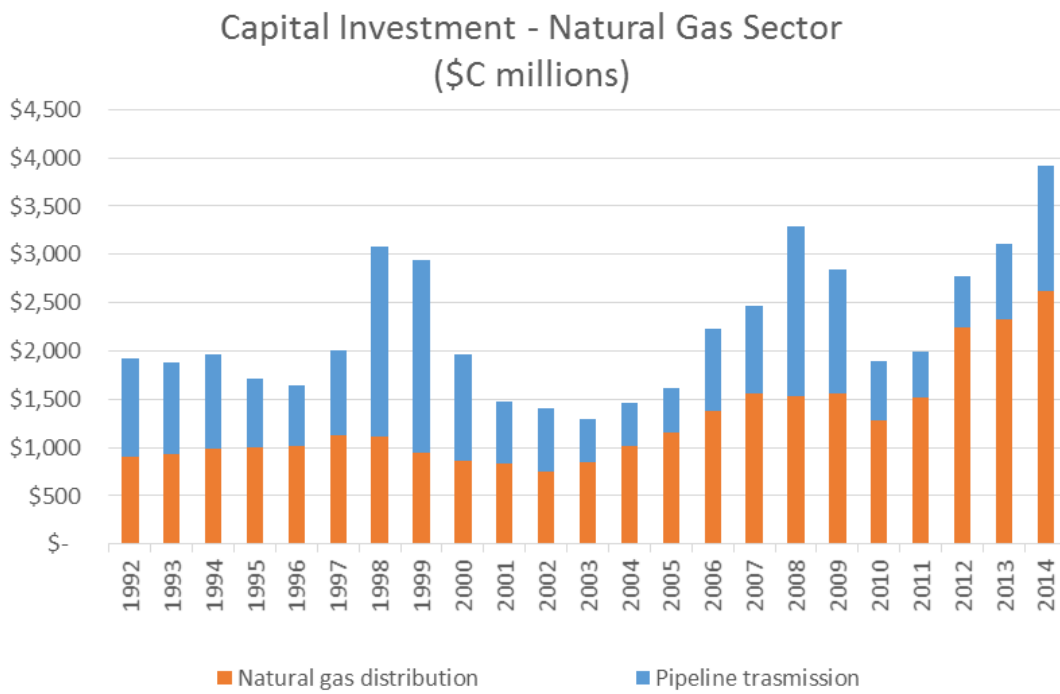
The customer impact calculations were conducted at a provincial level, and these results are presented separately for each of the provinces where the utility companies has information pertaining to potential pipeline expansion projects. In sum, the overall results are intended to broadly represent the potential for such projects and the benefit to Canada.

Exhibit 8 presents the potential distributor pipeline expansion expenditures for the provinces of Ontario, British Columbia, Quebec, and Manitoba. In terms of other provinces, Saskatchewan and Alberta are not included because access to and use of natural gas in these provinces is close to or surpasses 95%, leaving very few opportunities to connect further customers. New Brunswick and Nova Scotia are not included at this point due to the infancy of the utilities in those provinces, and the fact that the commodity price of natural gas in these regions lowers in some cases the value proposition for certain community expansions. Finally, Prince Edward Island, Newfoundland and Labrador, and the territories are not included as there is currently no natural gas pipeline/distribution in these regions.[21]

The pipeline expansion investments considered here are expected to occur in a five-year period, from 2016 to 2020. This means that all new pipelines and related facilities, totalling $1.3 billion, would be spent/capitalized out over this five-year term, averaging around $260 million per annum. For comparison, Exhibit 7 shows historical pipeline capital investments by gas utilities. Looking just at the last five years of data, from 2009-2013, the total investment by distribution utilities has been approximately $10 billion, or $2 billion per annum.

[21] However, there is a small natural gas distribution system in the town of Inuvik, NWT in addition to a natural gas fuel power plant in the town which obtains natural gas in LNG form via truck delivery from British Columbia.

Exhibit 7 Historical Level of Investment in the Natural Gas Sector



Source: StatCan 031-0002, CGA

It is important to note that while the pipelines would be built to the communities in a five-year period, not all newly eligible customers are expected to convert immediately, so some household or commercial service line costs are also included from 2021 to 2025. The national total distributor capital expenditures required to expand pipeline access to the customers considered in this study is just over $CDN 1.3 billion, spread out annually as shown in Exhibit 8. This represents full project costs to install roughly 6,000 km of pipeline and service lines.

Exhibit 8 Distributor Expenditures for Natural Gas Expansion Projects, by Year

Province	Distributor Capital Expenditures by Year ($ Million)							
	2016	2017	2018	2019	2020	2016-2020 Sub-Total	2021-2025 Sub-Total	Total
Ontario	92.1	171.9	229.6	183.6	88.2	**765.3**	**13.4**	**778.8**
BC	63.8	63.8	63.8	63.8	63.8	**319.1**	**19.1**	**338.2**
Quebec	15.0	37.5	45.0	37.5	15.0	**150.1**	**2.3**	**152.4**
Manitoba	3.7	9.3	11.2	9.3	3.7	**37.3**	**0.7**	**37.9**
Canada	**174.6**	**282.6**	**349.6**	**294.2**	**170.7**	**1,271.8**	**35.5**	**1,307.3**

Exhibit 9 presents the national total of new customers expected to switch to natural gas in each province, based on the above investments in pipeline infrastructure. This study only considers the benefit of customers converting fuels between 2016 and 2025, with the expectation that roughly 45% of eligible residential and commercial customers would have converted within 10 years of natural gas being made available to them. Further adoption of natural gas, beyond the number of customers included here, would represent additional economic benefits above and beyond what is presented in this study. Note that none of the natural gas distributors anticipate the conversion of any power generation facilities to natural gas as a result of these expansions. However, there always remains the opportunity for cogeneration or combined cycle plants if natural gas is brought into new regions.

Exhibit 9 Number of New Natural Gas Customers, by Province (2016-2025)

Province	New Customers by Type			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	25,080	2,056	53	**27,190**
BC	11,602	438	2	**12,041**
Quebec	3,870	108	16	**3,994**
Manitoba	4,105	785	2	**4,892**
Canada	**44,657**	**3,387**	**73**	**48,117**

Where the above exhibit highlights how the new customers are assumed to be distributed between provinces, Exhibit 10 shows the distribution of fuel types from which new customers are expected to convert.

Exhibit 10 Number of New Natural Gas Customers, by Fuel Type (2016-2025)

Previous Heating Fuel	New Customers by Type			
	Residential	Commercial / Institutional	Industrial	Total
Heating Oil	20,240	1,211	27	**21,478**
Propane	16,440	1,104	26	**17,570**
Electricity	7,738	1,066	17	**8,820**
Biomass	239	5	1	**245**
Heavy Oil	-	-	3	**3**
Total	**44,657**	**3,387**	**73**	**48,117**

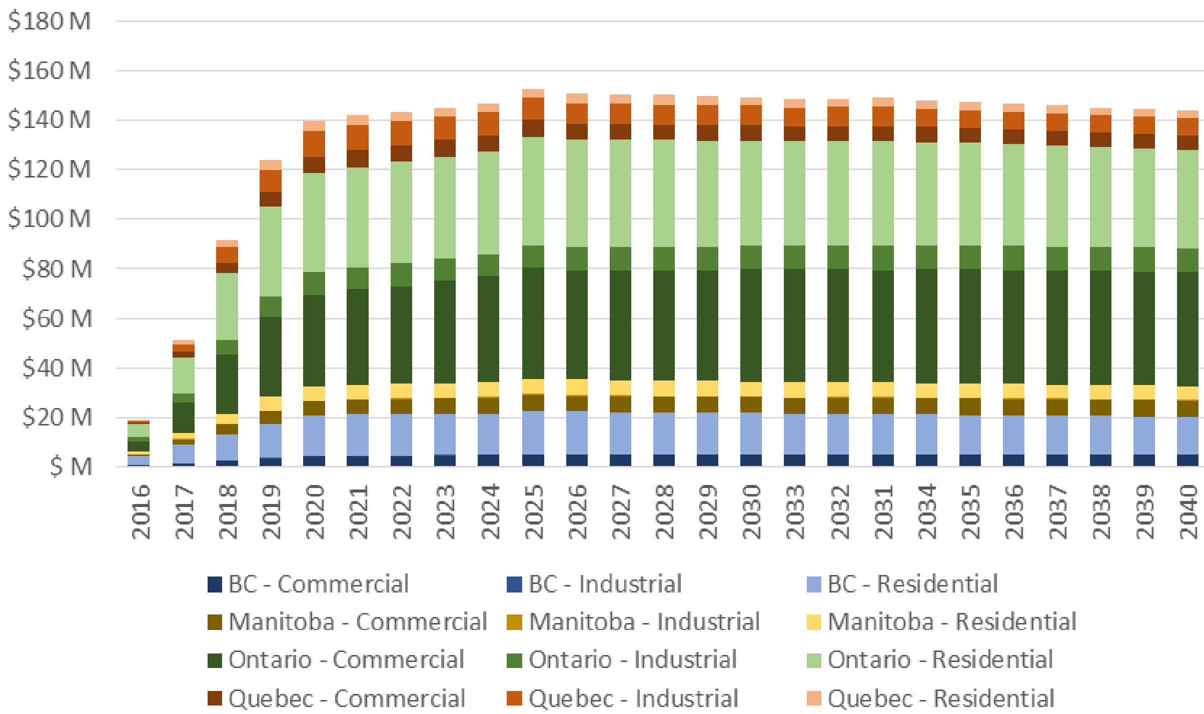
Exhibit 11 presents the national total of annual gas consumption from new customers in 2025, which captures all of the customers assumed to be connected in this study. While the previous exhibit showed that most new customers are in the residential sector, higher commercial and industrial consumption per facility results in significant annual consumption in these sectors as well. The residential sector represents around 45% of new gas consumption, followed by commercial (35%), and industrial (20%).

Exhibit 11 Annual Natural Gas Consumption from New Customers (GJ p.a. in 2025)

Province	New Annual Gas Consumption by Customer Type (GJ p.a.)			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	2,146,615	1,751,900	589,722	**4,488,237**
BC	992,967	259,438	20,000	**1,272,405**
Quebec	331,230	569,928	1,093,295	**1,994,453**
Manitoba	351,330	353,250	20,000	**724,580**
Canada	**3,822,142**	**2,934,515**	**1,723,017**	**8,479,674**

Exhibit 12 presents the annual customer fuel cost savings[22] over time, broken down by province and customer type. For example, Ontario is represented by the green shaded sections in each bar, highlighting that the majority of the cost savings will be in this province. It is also the province with the highest pipeline expansion expenditures. This exhibit also shows that Ontario's residential sector (lightest green) and commercial sector (darkest green) make up the majority of this province's fuel cost savings, with significantly less industrial savings in Ontario. Finally, the exhibit also shows that the relative cost savings of different sectors varies between provinces.

Exhibit 12 Annual Fuel Cost Savings of New Customers (2015 $Million)[22]



In the above exhibit, fuel cost savings ramp up between 2016 and 2020, as the bulk of new customers considered in this study become connected to natural gas supplies. From 2021 to 2025, savings

[22] These values represent the annual net fuel cost savings, in real 2015 Canadian dollars, for all new natural gas customers. This takes into account delivered fuel costs and relative equipment efficiency. These savings do not include costs to buy and install new gas burning equipment, costs for CO2 emissions, or all the costs for distribution system expansions.

continue to climb, as a smaller number of customers continue to connect to the pipeline infrastructure. From 2026 onwards savings remain relatively stable, decreasing only slightly as gas prices creep up and residential building envelopes are considered to improve their thermal integrity. Provincial versions of the above combined exhibit can be found in Appendix B of this report. Additionally, the average per customer savings are presented below in Exhibit 13. [23]

Exhibit 13 Average Annual Fuel Cost Savings, by Province (2016-2040)

Province	Average Annual Fuel Cost Savings, per Customer ($2015)			
	Residential	Commercial / Institutional [23]	Industrial [23]	2016-2040 Average
Ontario	1,773	22,115	177,072	**3,707**
BC	1,526	11,261	103,120	**1,905**
Quebec	976	60,276	520,981	**4,860**
Manitoba	1,549	8,413	150,764	**2,735**
Canada	**1,619**	**18,764**	**249,722**	**3,253**

Inter-provincial differences are driven by variances in fuel prices and by different expectations in each province for the fuel types from which new natural gas customers would convert. To compare their differences, Exhibit 14 presents the average per customer savings broken down by fuel type. [23]

Exhibit 14 Average Annual Fuel Cost Savings, by Fuel Type (2016-2040)

Previous Fuel Type	Average Annual Fuel Cost Savings, per Customer ($2015)			
	Residential	Commercial / Institutional [23]	Industrial [23]	2016-2040 Average
Heating Oil	1,758	19,426	137,829	**2,956**
Propane	1,544	11,969	342,275	**2,757**
Electricity	1,453	25,046	314,833	**4,988**
Biomass	454	19,736	321,752	**2,009**
Heavy Oil	-	-	18,792	**18,792**
Average	**1,619**	**18,764**	**249,722**	**3,253**

Exhibit 15 presents the national total expenditures of new customers on natural burning gas equipment and appliances. These costs are above and beyond the distributor pipeline expenditures presented earlier in Exhibit 8. These costs are somewhat mitigated in the model by the assumption that on average the existing heating equipment was at the mid-way point in its useful life, giving some value to the early replacement (methodology refers to net expenditures).

[23] Note that the annual fuel savings for industrial and commercial/institutional customers can be highly variable. The size and scale of a facility will greatly impact the annual fuel savings.

Exhibit 15 Customer Expenditures for New Natural Gas Equipment

Province	Customer Expenses for New Natural Gas Equipment by Customer Type ($)			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	125,402,344	46,251,250	2,410,000	**174,063,594**
BC	58,007,813	8,750,000	100,000	**66,857,813**
Quebec	19,350,000	2,160,000	1,920,000	**23,430,000**
Manitoba	20,524,219	15,700,000	100,000	**36,324,219**
Canada	**223,284,375**	**72,861,250**	**4,530,000**	**300,675,625**

In addition to the annual fuel costs savings, a Net Present Value calculation is used to compare all of the increased customer costs to the savings, and show what the net benefit would be for new customers today (2015 dollars).

Exhibit 16 presents the NPV of the total net savings for fuel conversions from the customer's perspective. This combines the present value (in constant 2015 dollars) of fuel cost savings (2016-2040) with the net costs for early replacement of appliances and equipment, as well as the increased expansion surcharge customer fees for residential and commercial customers in Ontario. The Canada-wide present value of new customer benefits is shown here to be over $1.4 billion. It is important to keep in mind that since this present value is taken from the customer perspective, it does not directly include the distributors' full costs for pipeline expansion infrastructure.

Exhibit 16 Net Present Value of Total Net Savings for New Customers

Province	Net Present Value of Total Net Customer Savings by Customer Type ($2015)			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	356,623,670	403,260,620	107,247,946	**867,132,236**
BC	175,526,579	50,404,468	2,368,920	**228,299,968**
Quebec	36,210,623	73,243,412	100,032,954	**209,486,988**
Manitoba	62,883,609	65,941,314	3,459,784	**132,284,707**
Canada	**631,244,481**	**592,849,814**	**213,109,604**	**1,437,203,899**

To account for the distributors' full pipeline expansion costs, the macro-economic modelling estimated the 'shortfall' in distributor revenues. This shortfall highlights that the maximum service rates distributors stand to receive from new customers, based on the current price forecast, are less than the capital costs for expansion. The present value of the distributors' funding shortfall was estimated to be $486 million, for the projects considered in this study. Combining this shortfall with the customer NPV from above shows that large benefits still remain for society as a whole, even taking into account the full shortfall, with an aggregate NPV of the expansion benefits around $950 million.

Macro-Economic Impacts

This section starts with a summary of the economic benefits from the expansion of natural gas distribution pipelines, followed by a closer look at each of the economic indicators considered here. The economic modeling was conducted at a national level, so these results are presented for Canada as a whole. It is important to keep in mind that all of the results represent impacts specific to the Canadian economy, and have already been adjusted to remove any increased spending on imports.

Exhibit 17 summarizes the results of the economic modelling, presenting the three primary economic indicators targeted in this project. It is expected that over a 25-year period these expansion projects would add $1.7 billion to Canada's GDP, contribute support of 31,500 net job-years, and increase government revenues by over $600 million. The results are also provided separately for direct/indirect benefits and induced benefits, and are also presented both as the national total impacts over the study period and the average annual impacts.

Exhibit 17 Summary of Economic Impacts from Pipeline Distribution Expansion

Type of Economic Benefit	Total Impacts over Study Period (2016-2040)			Average Annual Impacts		
	Direct & Indirect Impacts	Induced Impacts	Total Impacts (2016-2040)	Direct & Indirect Impacts	Induced Impacts	Average Annual Impacts
GDP ($Million)	1,104	626	**1,730**	44	25	**69**
Employment (Job-years)	23,732	7,777	**31,509**	949	311	**1,260**
Government Taxes and Revenues ($Million)	395	224	**619**	16	9	**25**

Although the upfront capital expenditures for natural gas distributors are large, at around $1.3 billion, these pipeline expansion projects offer significant benefits to consumers and the Canadian economy. The benefits found in this study are primarily for the new natural gas consumers, who achieve significant fuel cost savings. Despite the large annual energy cost savings, the ability of utilities to connect these consumers is limited by regulations that set out the rules and economic parameters for community connection. In British Columbia and Ontario, measures are being examined that could improve the economics of connecting communities by making changes to the regulated economic tests.

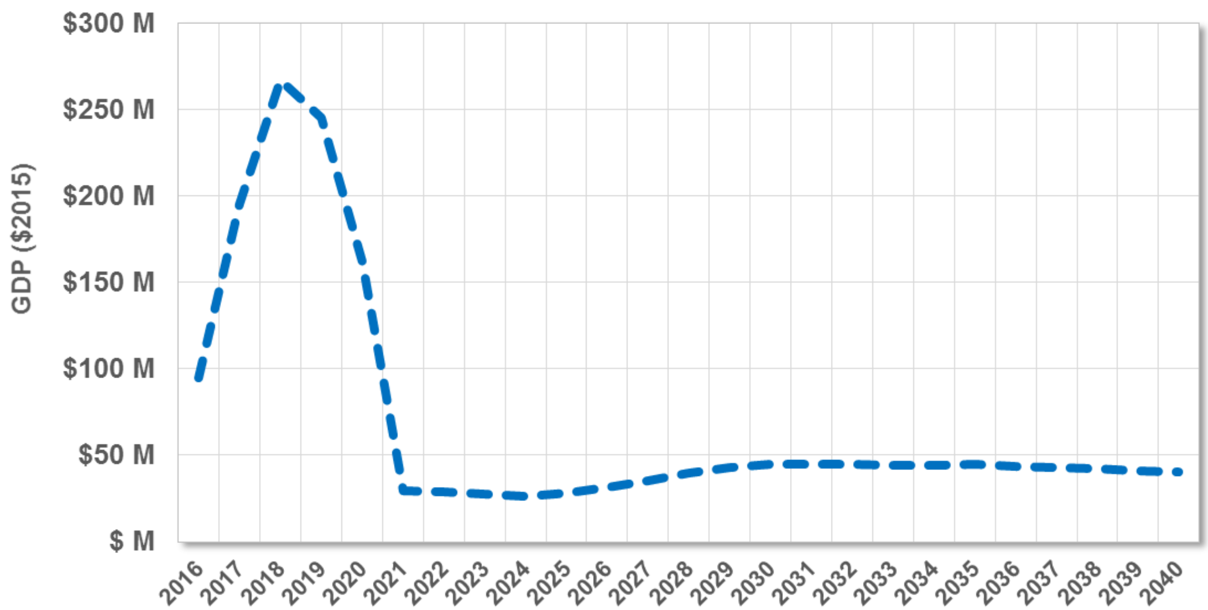
As noted earlier, the present value of the distributors' funding shortfall was estimated to be $486 million, when comparing expected increases to distributor revenues against increased costs (infrastructure, commodity, maintenance, etc.). In accounting for this shortfall, the study was agnostic to the specific mechanism for meeting additional funding requirements for such expansions. It was assumed that in all cases consumers would fund the expansion one way or another, so this shortfall is balanced through reduced consumer spending, allowing the report to focus on the overall benefits to the economy. It is however noteworthy that government revenue increases over this 25 year period would represent a significant portion of the overall investment requirement.

It is also important to keep in mind that although we have limited the study period to 25 years, a certain level of economic impact can reasonably be expected to continue within the Canadian economy after 2040. However, this study needed to draw a line somewhere, and with the vast majority of the infrastructure investment being anticipated between 2016 and 2020, accounting for the benefits until 20 years after this point was considered to strike a reasonable balance.

Annual impacts for each of the three economic indicators are shown separately in the following three exhibits.

Exhibit 18 shows how the national total value added (GDP) changes over the study period. Annual GDP impacts spike in the early years, peaking around $260 million, since almost all of the distributor capital expenditures occur between 2015 and 2020. During that same period most of the customers are connected as well, and start to achieve fuel cost savings, which in turn drives customer re-spending GDP impacts. In the remaining years, annual GDP impacts remain relatively steady, with some adjustments as a smaller number of customers continue to become connected, as the 10-year period for expansion surcharges expires, as baseline equipment efficiencies were assumed to rise, and as fuel prices change.

Exhibit 18 Annual Increase in Canadian Gross Domestic Product



It is important to note that these GDP results, as well as the other economic modeling results, represent impacts for Canada and already factor out leakages (economic effects in other countries attributed to imported goods or services).

Exhibit 19 presents the annual Canadian job impacts of the pipeline expansion projects. As with the previous GDP exhibit, pipeline capital expenditures and customer equipment purchases create a spike in employment impacts early in the study period, while customer re-spending of fuel cost savings forms a steady baseline of annual impacts in later years.

Exhibit 19 Annual Increase in Canadian Employment

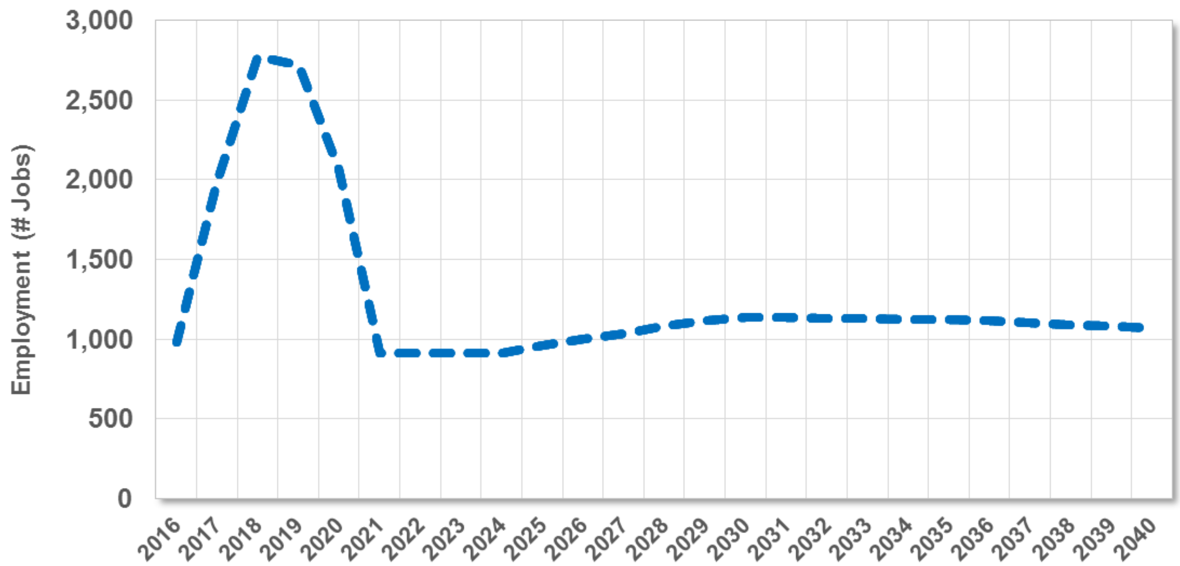
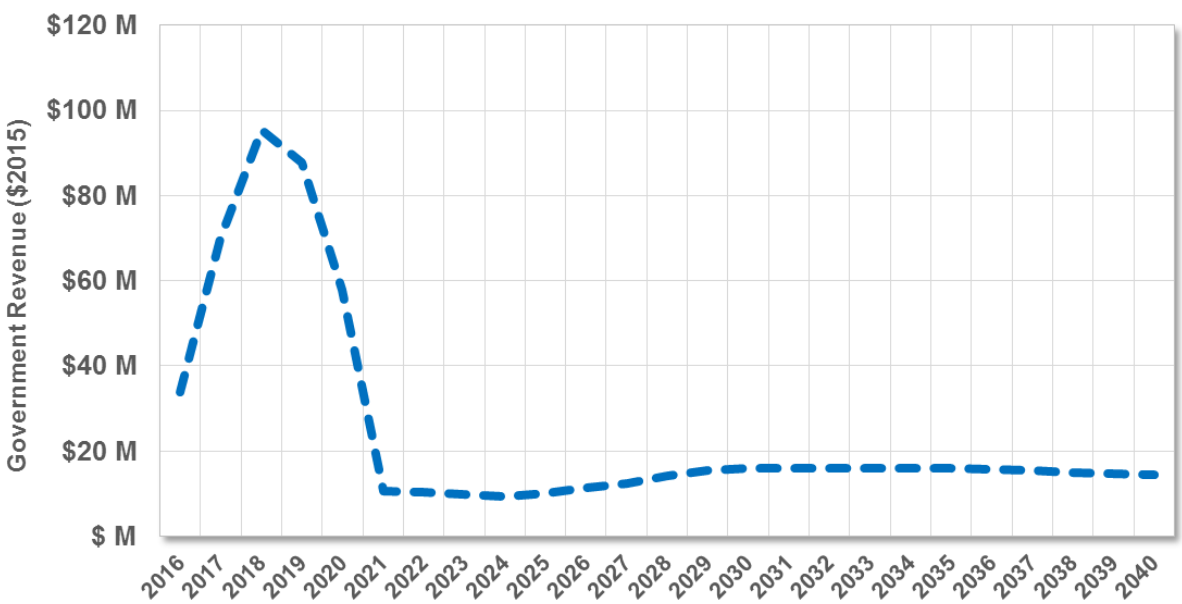


Exhibit 20 estimates the annual impacts on Canadian government taxes and revenues from the pipeline expansion projects. This is presented as a combined total for federal, provincial, and municipal governments, and follows the same profile as GDP impacts.

Exhibit 20 Annual Increase in Government Taxes and Revenues



CO2 Emission Price Sensitivity

It is important to understand how the customer impacts calculated in this study would be affected by existing or future CO2 emission prices. The NEB fuel price forecasts used in this study do not include any CO2 emission prices,[24] and results before this section have not accounted for any CO2 emission prices. To establish the sensitivity of results to GHG prices, emission factors were used to calculate the net changes to GHG emissions from the natural gas conversions, and two CO2 emission price scenarios were considered.

- The low CO2 emission price scenario is reflective of existing or anticipated CO2 emission prices in various provinces.
- The high price scenario highlights potential impacts from CO2 emission prices significantly higher than what is currently planned.

Along with the net changes to annual (2025) GHG emissions, presented below in Exhibit 21 and Exhibit 22, subsequent exhibits in this section highlight the impact of CO2 emission prices on the new natural gas customers considered in this study.

Overall, the conversions considered in this study would result in a decrease in annual GHG emissions equivalent to over 75,000 tonnes of CO2 per year. This information shows that CO2 emission price impacts are strongly dependent on the fuel-mix being displaced by natural gas.

The business case for replacing heating oil, propane, and heavy oil with natural gas is improved by CO2 emission prices, as these fuels are more carbon-intensive than natural gas. However, the merit for converting electric and biomass heating is reduced by the increased costs of CO2 emission prices.

Exhibit 21 Net Annual GHG Emission Reductions, by Province

Province	Net Annual GHG Emission Reductions by Province (tCO2e), 2025			
	Residential	Commercial / Institutional	Industrial	Total
Ontario	24,703	10,267	4,857	**39,827**
BC	7,257	905	591	**8,753**
Quebec	3,179	5,379	9,251	**17,809**
Manitoba	5,464	4,958	259	**10,680**
Canada	**40,602**	**21,509**	**14,958**	**77,069**

[24] The NEB Energy Futures study accounts for CO2 emission prices at large industrial sites in Quebec when estimating impacts on consumption growth in the province, but no CO2 emission prices are included in the fuel price forecasts referenced here.

Exhibit 22 Net Annual GHG Emission Reductions, by Fuel Type

Previous Heating Fuel	Net Annual GHG Emission Reductions by Previous Fuel Type (tCO2e), 2025			
	Residential	Commercial / Institutional	Industrial	Total
Heating Oil	48,451	31,922	14,449	**94,822**
Propane	16,153	15,431	12,714	**44,297**
Electricity	(23,671)	(24,451)	(9,708)	**(57,830)**
Biomass	(331)	(1,393)	(2,685)	**(4,408)**
Heavy Oil	-	-	188	**188**
Total	**40,602**	**21,509**	**14,958**	**77,069**

The low CO2 emission price scenario considers a price frozen at $15 per tonne of CO2 equivalent emissions throughout the entire study period (2016-2040), for Quebec, Ontario, and Manitoba.[25] For British Columbia, this scenario initially considers $30 / tCO2e, and rises to $40 / tCO2e in 2020. The high price scenario considers a price of $100 / tCO2e for all provinces, through-out the entire study period.

Exhibit 23 and Exhibit 24 demonstrate how the inclusion of low and high CO2 emission prices would impact the average annual fuel cost savings of new natural gas customers, respectively. Along with the cost savings under each scenario, the percent increase to the net cost savings from the inclusion of CO2 emission prices is included. These exhibits show that, on average, residential customer net fuel cost savings would increase by 1.3% and 6.5% under the low and high CO2 emission price scenarios, respectively, compared to not accounting for any GHG price. It is important to keep in mind that CO2 emission prices will cause natural gas fuel costs to rise substantially, in absolute terms, and customers will be paying larger heating bills under these scenarios. However, the increased net fuel cost savings under these scenarios highlights that average customer costs would have increased even more if they were still using their previous fuels. The equivalent annual cost savings without consideration of a CO2 emission price were presented earlier, in Exhibit 13.

Exhibit 23 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040)

Province	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [26]	Net Cost Savings ($)	CO2 Change (%) [26]	Net Cost Savings ($)	CO2 Change (%) [26]
Ontario	1,790	1.0%	22,194	0.4%	178,501	0.8%
BC	1,555	1.9%	11,348	0.8%	114,837	11.4%
Quebec	991	1.5%	61,060	1.3%	529,997	1.7%
Manitoba	1,572	1.4%	8,510	1.2%	152,758	1.3%
Canada	**1,640**	**1.3%**	**18,871**	**0.6%**	**253,112**	**1.4%**

[25] The study authors are not aware of plans for a CO2 emission price in Manitoba, but the province is included here to highlight potential impacts.
[26] Percent change from case with no CO2 emission price.

Exhibit 24 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Province (2016-2040)

Province	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]
Ontario	1,886	6.4%	22,640	2.4%	186,600	5.4%
BC	1,602	5.0%	11,489	2.0%	133,180	29.2%
Quebec	1,074	10.1%	65,507	8.7%	581,090	11.5%
Manitoba	1,698	9.6%	9,065	7.8%	164,060	8.8%
Canada	**1,725**	**6.5%**	**19,431**	**3.6%**	**271,005**	**8.5%**

As with the overall changes to GHG emission levels, the exhibits above show significant differences between provinces, driven by the differences in the fuel-mixes expected to be converted to natural gas.

To better understand the impact of provincial fuel-mixes, Exhibit 25 and Exhibit 26 present the annual fuel cost savings under the two CO2 emission price scenarios, separated by fuel type. While the average increase to residential customer fuel cost savings are the same, at 1.3% and 6.5%, the changes between fuel types are significant. Once again, it is important to keep in mind that CO2 emission prices will cause natural gas fuel costs to rise substantially, in absolute terms, and customers will be paying larger heating bills under these scenarios. However, the changes to net fuel cost savings under these scenarios highlight which previous fuel types would have smaller cost increases from a CO2 emission price. For example, residential customers converting from heating oil to natural gas will see their annual cost savings increase by 14.5% under the high CO2 emission price scenario, while on average customers converting from electric heating will see their savings decreased by 20.1% from the same GHG prices. The equivalent annual cost savings by fuel type, without consideration of a GHG price, were presented earlier, in Exhibit 15.

Exhibit 25 Low CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040)

Previous Fuel Type	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]	Net Cost Savings ($)	CO2 Change (%) [27]
Heating Oil	1,821	3.6%	19,910	2.5%	146,494	6.3%
Propane	1,561	1.1%	12,204	2.0%	349,703	2.2%
Electricity	1,373	-5.5%	24,613	-1.7%	306,079	-2.8%
Biomass	338	-25.6%	15,868	-19.6%	271,416	-15.6%
Heavy Oil	-	-	-	-	21,310	13.4%
Average	**1,640**	**1.3%**	**18,871**	**0.6%**	**253,112**	**1.4%**

[27] Percent change from case with no CO2 emission price.

Exhibit 26 High CO2 Emission Price - Average Annual Fuel Cost Savings, by Fuel Type (2016-2040)

Previous Fuel Type	Average Annual Fuel Cost Savings, per Customer ($2015)					
	Residential		Commercial/Institutional		Industrial	
	Net Cost Savings ($)	CO2 Change (%) [28]	Net Cost Savings ($)	CO2 Change (%) [28]	Net Cost Savings ($)	CO2 Change (%) [28]
Heating Oil	2,013	14.5%	22,106	13.8%	192,859	39.9%
Propane	1,658	7.4%	13,420	12.1%	391,798	14.5%
Electricity	1,160	-20.1%	22,749	-9.2%	256,476	-18.5%
Biomass	158	-65.3%	(6,053)	-130.7%	(13,823)	-104.3%
Heavy Oil	-	-	-	-	26,389	40.4%
Average	**1,725**	**6.5%**	**19,431**	**3.6%**	**271,005**	**8.5%**

It is notable from the exhibits above that in the low CO2 emission price scenario, even though cost savings are reduced for customers converting from some fuel types, all customers can still achieve cost savings through natural gas conversions. Only in the high CO2 emission price scenario do some conversions no longer achieve cost savings for customers, more specifically biomass conversions.

Exhibit 27 and Exhibit 28 present the NPV of the fuel conversions from the customer's perspective, for the low and high CO2 emission price scenarios, respectively. Overall, CO2 emission prices do not cause large changes to the Canada-wide customer NPV, from the $1.44 billion calculated without a GHG price. For example, the overall customer NPV in the high price scenario is 7.1% higher. Again, CO2 emission prices will cause natural gas fuel costs to rise substantially; however, the increased NPV highlights that the average customer would see a smaller cost increase than if they were still reliant on their previous fuels. The equivalent NPVs without consideration of a GHG price were presented earlier, in Exhibit 16. It is important to keep in mind that since this present value is taken from the customer perspective, it does not directly include the distributor's full costs for pipeline expansion infrastructure; as noted earlier, the present value of this shortfall was estimated to be $486 million.

Exhibit 27 Low CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective

Province	Net Present Value from New Customer Perspective by Customer Type ($2015)				
	Residential	Commercial / Institutional	Industrial	Total	CO2 Change (%) [28]
Ontario	361,634,294	405,175,381	108,171,510	**874,981,185**	**0.9%**
BC	179,559,865	50,881,874	2,642,222	**233,083,962**	**2.1%**
Quebec	36,889,217	74,251,196	101,794,558	**212,934,971**	**1.6%**
Manitoba	63,949,986	66,823,199	3,507,837	**134,281,022**	**1.5%**
Canada	**642,033,362**	**597,131,650**	**216,116,127**	**1,455,281,139**	**1.3%**

[28] Percent change from case with no CO2 emission price.

Exhibit 28 High CO2 Emission Price - NPV of Fuel Conversion from New Customer Perspective

Province	Net Present Value from New Customer Perspective by Customer Type ($2015)				
	Residential	Commercial / Institutional	Industrial	Total	CO2 Change (%) [29]
Ontario	390,027,828	416,025,691	113,405,042	**919,458,560**	**6.0%**
BC	186,377,989	51,685,389	3,081,911	**241,145,289**	**5.6%**
Quebec	40,734,584	79,961,971	111,776,981	**232,473,537**	**11.0%**
Manitoba	69,992,786	71,820,549	3,780,141	**145,593,477**	**10.1%**
Canada	**687,133,187**	**619,493,601**	**232,044,075**	**1,538,670,863**	**7.1%**

[29] Percent change from case with no CO2 emission price.

Appendix A Methodology and Assumptions

The next sections discuss key steps in the study process in more detail, provide information on some key assumptions driving the analysis, and describe the IMPLAN model in more detail.

Distributor Surveys

The basis for this analysis is information provided by Canadian natural gas distribution utilities, with regards to their understanding of potential natural gas distribution pipeline expansion projects and associated cost and consumer connection opportunities. An excel-based data collection template was sent out to the distributors by the CGA, providing ICF with information on the number of new customers (by type), the previous fuel types used by these customers, expectations for the level of natural gas consumption by new customers, and the breakdown of capital investments for these expansion projects. Some distributors provided information on potential projects in other formats, or left certain areas of the survey blank, so ICF filled any gaps with information from other similar respondents, or with conservative assumptions.

Customer Impact Calculations

The customer impact calculations took the results of the distributor surveys, and processed this information with several other key data sources to establish the metrics from which the merit of projects can be assessed, including the total costs and fuel cost savings.

Some of the outputs of the customer impact calculations came directly from the distributor surveys, such as the project costs for pipeline expansion. For other calculations, such as the fuel cost savings, the customer impact calculations brought together several pieces of information to compute the required results. The two primary calculations are as follows:

- **Fuel Cost Savings:** The customer impact calculations computed the total natural gas consumption (GJ) from new customers, and then estimated the equivalent consumption (GJ) from previous fuels, based on assumed relative fuel and equipment efficiencies. The price forecasts for both natural gas and the previous fuels were then used to establish the net fuel cost savings.
- **Customer Net Present Value:** The NPV from the customer's perspective was calculated from computing the present values of fuel cost savings, net equipment purchase expenditures, and the expansion surcharge customer fees.

The sub-sections below describe the data sources and key assumptions in more detail.

Number of Customer Conversions
In their survey responses, natural gas distributors provided the number of customer conversions they would anticipate in the initial 5 year period. The distributors also expressed their expectations that if the pipeline infrastructure was built, more customers would continue to convert to natural gas after the first 5 year period, with a lower barrier to entry (only service line required). So it was agreed upon with the distributor working group that based on their past experiences the study should consider 45% of eligible customers would convert within 10 years of gaining distribution access, with 70% of those conversions occurring in the first 5 years. These expectations were used to estimate the additional customers connecting beyond the initial 5 year period, which had been provided by the distributors.

Customer Natural Gas Use

All new residential customers are assumed to consume 90 GJ/year of natural gas until 2020, with an annual 1% decrease thereafter, from efficiency measures such as building envelope improvements. It is important to note that these 'new' residential customers are primarily expected to be older homes, in regions without access to natural gas (newly built housing stock would on average have lower heating requirements).

Commercial and institutional consumption per customer ranges from 450 GJ/year to 5,277 GJ/year, depending on the province, and is based on information provided in response to the gas distributor surveys. Industrial consumption per customer ranges from 10,000 GJ/year to 110,388 GJ/year, and is also based on survey responses.

Fuel Use Profiles

The customer fuel consumption prior to converting to natural gas is calculated based on the assumed new customer natural gas use, and the relative efficiencies of the two heating methods. Calculating the baseline heating requirements directly from the assumed levels of new customer gas consumption ensures that the heating loads before and after the conversion match, allowing for the natural gas heating costs to be compared with the previous fuel costs. Ranges of the assumed levels of efficiency for each heating method are listed below, based on efficiencies presented for a variety of heating fuels and equipment vintages in a Natural Resources Canada guide[30] to heating with natural gas. Internal ICF expertise and an Environmental Protection Agency (EPA) biomass report[31] were also used in establishing how these efficiency levels varied for the non-residential sectors.

- Natural gas heating equipment: 85-95%
- Electric heating equipment: 100%
- Propane, heating oil, and heavy fuel oil equipment: 60-97%
- Wood / biomass equipment: 45-75%

It was assumed that existing equipment in these older vintage buildings was of conventional efficiency, but that equipment was on average about half-way through its life, so the heating equipment would have been replaced anyway in 8 to 10 years. It was also assumed that if this natural gas expansion project had not occurred, the older heating equipment would have been replaced by more efficient equipment using the same fuel-type when it reached its end of life, with an even split between standard (minimum required) efficiency and high-efficiency equipment. The result of this shifting baseline is a more conservative estimate of customer savings through natural gas heating, since the savings from efficient new natural gas equipment gradually decrease over time, as the baseline efficiency of other types of heating equipment rises.

Fuel Prices

- Prices for natural gas, electricity, and heating oil were taken from a National Energy Board (NEB) forecast, using their 'Low Price Scenario'.[32] This forecast provides delivered fuel prices up to 2035 by province and customer type (residential, commercial, industrial), and prices thereafter were frozen at 2035 levels until 2040. While this November 2013 forecast does not capture the most recent shifts in the energy market, the use of the 'low price scenario' was considered to provide a comprehensive (includes province and customer-type specific data) and conservative benchmark of different price categories.[33]

[30] Natural Resources Canada, Heating with Gas, 2012. http://www.nrcan.gc.ca/sites/oee.nrcan.gc.ca/files/pdf/publications/infosource/pub/home/Heating_With_Gas.pdf
[31] EPA, Biomass Combined Heat and Power Catalog of Technologies, 2007. http://www.epa.gov/chp/documents/biomass_chp_catalog_part5.pdf
[32] National Energy Board, Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035, 2013.
[33] This analysis considers real dollars. However, the 2012 real dollars from the NEB forecast have not been increased based on inflation to 2015, since these forecasts already overestimate current fuel prices (even in the low scenario).

- It is important to note that the economic impacts highlighted in this study would be higher if fuel prices were based on the NEB forecast's 'reference case scenario' or 'high price scenario'. Even though natural gas prices are higher in those forecasts than in the 'low price scenario', the prices for other fuels (heating oil, etc.) to be displaced by natural gas are also higher, resulting in greater savings and making the 'low price scenario' used in this study the more conservative option.
- While the NEB oil price forecasts were prepared before the recent drop in world oil prices, the NEB low price scenario is based on an average WTI oil benchmark price of $USD 76 / barrel, from 2016 to 2035. This average NEB price is slightly lower than the equivalent average from the current EIA forecast for WTI prices over this period ($USD 88 / barrel).[34] In fact the average WTI prices from 2016 to 2025 are less than 5% different in these two forecasts, with greater discrepancies emerging after 2025 when price growth accelerates in the EIA forecast, but grows more slowly in this NEB scenario.
- Propane and heavy oil prices have historically been correlated to crude oil prices. The same NEB forecast included the price expectations for crude oil up to 2035 that were used in their assessment. Using monthly historical data from the U.S. Energy Information Administration (EIA), ICF established that the 10-year average ratio of crude oil[35] to heavy oil[36] prices (per GJ) was 85%, and residential delivered propane[37] was 205% of crude oil. EIA data[38] was also used to estimate commercial and industrial propane costs to be 77% and 70% of residential prices, respectively. These ratios were used to calculate the propane and heavy oil prices used over the study period, based on the NEB crude oil price forecast.
- The biomass price was established as $12/GJ in 2016, based on information provided to the CGA by natural gas distributors, and is assumed to rise by 1% annually.

Infrastructure Investments

The expected project costs for natural gas distribution pipeline expansion were provided by distributors in their survey responses. In addition, it was assumed in the customer impact calculations that annual distributor operations and maintenance (O&M) costs would be increased by the equivalent of 0.5% of the new project capital expenditures.

Net Customer Appliance and Equipment Purchases

The net cost to new customers for natural gas appliance and equipment purchases was calculated from the expected cost of new equipment, less the value of foregone replacements that equipment would have needed. The appliance and equipment expenditures per customer were based on data collected from the distributor surveys and estimates from ICF to fill gaps in certain regions. The value to customers from the foregone costs of eventually replacing existing equipment represents that even if customers were not converting to natural gas, over time their equipment and appliances would breakdown and need replacing. Some considerations about the treatment of these foregone costs through early replacement include:

- Calculations assume on average equipment is currently half-way through its useful life (i.e., equal distribution of equipment ages), and that equipment lives are 15-20 years.
- Calculations take the present value of this average future equipment replacement, and annualize the cost over the respective equipment life.
- In the overall economic modeling the decision about whether or not to include foregone costs has little impact. This is because reducing customer expenditures on new equipment lowers the equipment cost inputs for GDP impacts, but increases the customer spending inputs by the same amount. So this re-classification of costs balances out and has little overall impact.

[34] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2015 with projections to 2040, April 2015. http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf
[35] EIA, Cushing OK WTI Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M
[36] EIA, Refiner Petroleum Product Prices by Sales Type, http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm
[37] EIA, Weekly Heating Oil and Propane Prices (October-March), http://www.eia.gov/dnav/pet/pet_pri_wfr_a_epllpa_prs_dpgal_m.htm
[38] EIA, Propane (Consumer Grade) Prices by Sales Type, http://www.eia.gov/dnav/pet/pet_pri_prop_dcu_r10_a.htm

Customer Connection Fees

An expansion surcharge customer fee is included for new residential and commercial customers in Ontario only. This customer fee is envisioned as one way to offset the high distributor expansion costs. The expansion surcharge has only been included for Ontario, since to the CGA's knowledge, this is the only Canadian jurisdiction where it has been formally requested by distributors.

The hypothetical residential and commercial expansion surcharge fees are calculated based on the customer's delivered gas volumes, for a period of 10 years. These fees are based on a rate of $0.23/m^3.

Output to Economic Model

The final step of the customer impact calculations involved adding up all provincial results for use in economic model at a national level. These customer impact calculations have already computed the expenditure (price x quantity) calculations which serve as the inputs for assessing economic impacts. The economic model was developed to pull in the appropriate expenditures by category, and will apply the relevant factors to determine economic impacts.

Net GHG Emissions

Emission factors were used to calculate the net changes to GHG emissions from the natural gas conversions. First, emissions from the new natural gas customers were calculated, based on their assumed consumption. Then emissions were calculated for those same customers, based on emission factors for their previous heating fuel types. The new emissions were subtracted from the baseline emission levels to establish the net GHG savings. This means that while absolute impacts from CO2 emission prices on customer costs may be large, the net impact may remain small, if both the new and old fuel types result in similar levels of GHG emissions.

The emission factors used in this section to assess the CO2 emission price impacts are shown in Exhibit 29. These are established from Environment Canada's National Inventory Report, using Global Warming Potentials of 25 grams of CO2e per gram of CH4, and 298 grams of CO2e per gram of N2O. Biomass calculations also assume an energy content of 15 GJ / ton for wood fuel.[39] Note that CO2 prices were not considered to apply to GHG emissions from residential biomass (wood used for heating in homes).

[39] NC State University, Conversion Factors for Bioenergy. http://content.ces.ncsu.edu/conversion-factors-for-bioenergy.pdf

Exhibit 29 GHG Emission Factors

Fuel Type	GHG Emission Factors				
	Ontario	BC	Quebec	Manitoba	Units
Natural Gas	1,890.4	1,927.4	1,889.4	1,888.4	g CO2e/m^3 [40]
Electricity	110.0	9.1	3.4	4.0	g CO2e/kWh [41]
Heating Oil	2,727.4	2,727.4	2,727.4	2,727.4	g CO2e/L [42]
Heavy Oil	3,146.1	3,146.1	3,146.1	3,146.1	g CO2e/L [43]
Propane	1,539.9	1,539.9	1,539.9	1,539.9	g CO2e/L [44]
Biomass (Industrial/Commercial)	20.1	20.1	20.1	20.1	g CO2e/kg [45] (excluding CO2)
Biomass (Residential)	422.7	422.7	422.7	422.7	g CO2e/kg [46] (excluding CO2)

[40] Environment Canada, National Inventory Report, 2014, Section A8 (marketable natural gas)
[41] Environment Canada, National Inventory Report, 2014, Section A13 (consumption intensity from 2012)
[42] Environment Canada, National Inventory Report, 2014, Section A8 (light fuel oil - residential)
[43] Environment Canada, National Inventory Report, 2014, Section A8 (heavy fuel oil - industrial)
[44] Environment Canada, National Inventory Report, 2014, Section A8 (propane)
[45] Environment Canada, National Inventory Report, 2015, Section A8 (biomass - industrial combustion)
[46] Environment Canada, National Inventory Report, 2015, Section A8 (biomass - residential combustion)

IMPLAN Scenarios

The core of the economic modeling, which is discussed in the following section, is driven by the IMPLAN model. ICF used the Canadian version of the IMPLAN model to estimate the macro-economic impacts of expanding the natural gas distribution pipeline for Canadian customers, focusing on the national-level impacts. IMPLAN is a commonly used model for such analyses and produces results that are regularly used to evaluate economic outcomes (jobs, economic output, labour income, tax revenues, etc.).

An IMPLAN scenario was developed for each type of expenditure that needed to be factored into the economic modeling, with a total of 21 unique scenarios being considered in this project. IMPLAN's Canadian model contains impacts for 103 different sectors. So each IMPLAN expenditure scenario that ICF developed allocated the spending among the model's 103 core sectors.

For each IMPLAN scenario, ICF modeled the economic impacts from a nominal $100 million expenditure, with this total value divided between sectors according to the breakdown developed for that expenditure scenario. This modeling established the Canada-specific economic impacts (GDP, jobs, labour income, and induced benefits) resulting from $100 million of investment in each type of expenditure relevant to the distribution pipeline expansion. These results were then brought into an economic model spreadsheet, where the impacts are scaled, according to the ratio of the actual expenditures in each category to the $100 million nominal input.

Macro-Economic Modeling

The economic model organized expenditures from the customer impact calculations to enable application of the appropriate economic impact factors from IMPLAN. The model first calculates direct and indirect effects on the Canadian economy, which exclude the impacts to imports (leakages). The model then assesses the induced economic impacts that will result from these direct and indirect changes, as people who earn income through the direct and indirect activity spend that income.

While most of the required expenditures came directly from the customer impact calculations, some other data sources were required to provide a comprehensive breakdown of the impacts from increased natural gas deliveries. Assessing natural gas related impacts required sub-categories to more accurately distinguish between expenditures related to pipeline expansion, gas production, gas transportation, distributor O&M, and distributor revenue shortfalls. This more detailed breakdown of natural gas expenditures allowed the model to use more specific IMPLAN factors for each sub-category, and more realistically distributed the economic impacts over the study period (timeline reflects when major spending occurs, instead of when customers are charged for gas). The division of natural gas expenditures into sub-components was also important because the model needed to account for a 'shortfall' in distributor revenues, as the maximum revenues distributors stand to receive based on the current price forecast was found to be less than the sum of other natural gas expenditure categories.[47]

The three primary calculations in the economic model are as follows:

- **Gross Domestic Product:** The first step of calculations for value added or GDP impacts was reducing expenditures by factors from IMPLAN to remove leakages, as well as some other adjustments representing the sale of replaced fuel types into new markets. Each of the natural gas

[47] As discussed later in this section, the 'shortfall' reduces consumer spending impacts, to balance the investment requirements for expansion and the estimated increase in utility revenues.

expenditure sub-categories also had leakages removed, including an assessment of the percentage of natural gas sourced from Canada.

Next, the shortfall in distributor revenue was calculated. A net present value was taken of the 2016 to 2040 distributor revenues and expenditures. This present value was then amortized over a 25 year period, to establish an annual value that would reduce consumer spending in order to finance the pipeline expansion.

Finally, the induced and total impacts were calculated, again using factors from IMPLAN.

- **Employment:** Employment calculations followed a similar format to GDP, with expenditures brought in by category, and corresponding IMPLAN factors used to calculated direct and indirect job-year impacts, while removing any leakages. Some other adjustments were again made to the replaced fuel types, assuming most fuels would be re-sold into new markets with no net job impacts. The consumer spending impacts from the distributor shortfall in GDP calculations were also included here. Finally the corresponding IMPLAN induced employment ratio was applied to each category, to determine the additional jobs from these knock-on effects.

- **Government Revenue:** Increased government taxes and revenues were estimated based historical ratios of government revenue to GDP. These ratios were applied to the GDP impacts calculated above, to determine the revenue impacts. Separate ratios were used for federal, provincial, and municipal revenue to GDP, the total of which is presented with this study's results.

The sub-sections below describe the data sources and key assumptions in more detail.

Source of Natural Gas

Where natural gas used in each province is produced is important in determining whether the commodity costs from increased gas consumption will contribute to increased Canadian economic activity. This study captures economic impacts from the portion of gas considered to be produced in Canada, but includes no commodity cost impacts from gas produced in the U.S. (other impacts such as from distribution are still included for this gas).

ICF's natural gas market forecast was used to estimate the source of gas used in Canadian provinces over the study period. The resulting assumption used in the economic model is that 56% of the gas is expected to be produced in Canada, with the remaining 44% imported from the United States. [48]

Reduced Fuel Consumption

This study considers the expansion of natural gas distribution pipelines to enable natural gas to replace other heating fuels. The displacement of those previous fuels will have negative economic impacts. The approach in accounting for these impacts varies for different fuels, and is presented below.

- It is assumed that in most provinces, electricity that is replaced as a heating fuel is no longer generated. The exceptions to this are expected to be Quebec and Manitoba, where electricity consumption reductions could lead to greater power exports. For this reason 95% of the displaced electricity expenditures are counted towards negative GDP impacts, with the remaining 5% reflective of Quebec and Manitoba's portion of the national drop in electricity consumption. The same percentages are used to calculate job impacts from reduced electricity consumption.
- For other fuels (heating oil, heavy fuel oil, propane, and biomass) it is assumed that the decreased consumption will not be significant enough to lower production of these fuels. It is expected that the fuels will instead be sold into new markets, minimizing economic impacts. GDP calculations for these fuels include a negative impact corresponding to 15% of the original delivered costs, to

[48] Data is based on a "supply-source" analysis of results from ICF's Q3 (July) 2015 natural gas market forecast (GMM0715, run date 7/16/2015)

reflect that the new markets may be farther away and less profitable. This negative impact is increased to 30% for biomass, where there is more uncertainty about the market. Changes in the markets for these fuels are considered to have negligible job impacts, given that any price drops are likely offset by increased transportation costs (and corresponding jobs) to bring the fuel to more distant markets.[49]

Infrastructure Investments
The expenditures for pipeline and distribution system expansions were taken directly from the customer impact calculations.

Natural Gas Production Costs
The same NEB forecast that is relied upon for delivered fuel prices also included the price expectations for natural gas (Henry Hub) up to 2035 that were used in their assessment. To establish a commodity price for the portion of gas sourced from Canada, ICF multiplied this Henry Hub forecast by a typical ratio to AECO prices. A ratio of 87.4% was used between the two gas price benchmarks, based on the average of 5 years of historical data from ICF's Gas Market Model.

The above commodity prices were used to compute increases in expenditures for gas production, which were further split into three categories (capital spending on wells; O&M for wells; and production return on capital, royalties, and taxes). The portion of the total commodity costs directed towards capital spending and O&M were estimated by ICF, based on typical well installation and lifecycle costs. The remainder of the commodity costs were categorized as return on capital, royalties, and taxes.

Distributor O&M Costs and Pipeline Transportation Tolls
The annual increase in distributor O&M costs from the pipeline and distribution system expansion were estimated at 0.5% of the total project costs in the customer impact calculations, and the same costs were used in the economic modeling.

Additionally, the breakdown of natural gas expenditures needed to account for the pipeline transmission costs to deliver the gas, purchased at commodity prices, to the distributors' networks. These costs are assumed to be $1/GJ. This was found to be an appropriate average, while it is expected that the transportation tolls would be higher for gas transported to eastern Canada from the west, but lower for gas shipped there from the U.S.'s Marcellus region and for gas produced and shipped within western Canada.

Distributor Shortfall
As part of the economic impact calculations, the potential increase in natural gas distributor revenues was compared to their increased costs. The concept here was that since the capital investments required for pipeline expansion are higher than the default increases to utility revenues, consumers would have to fund this 'shortfall', and so the economic impacts from re-spending of fuel cost savings by new customers was reduced accordingly. This conservative approach avoids overestimating economic benefits, and is detailed below.

The increased distributor costs are represented by the infrastructure investments, natural gas production (commodity) costs, distributor O&M costs, and pipeline transportation tolls. The increased distributor revenues are represented by the delivered gas volumes multiplied by the weighted average of NEB prices, plus the expansion surcharge fees collected. The average NEB delivered price over the study period is $10.7/GJ. This compares to increased distributor costs amounting to $13.1/GJ. This implies a shortfall of $2.4/GJ, which would partly be recouped directly from consumers in the form of the expansion surcharge customer fees ($1.3/GJ).

[49] This assumption represents a maximum potential error of about 34 jobs/year, if all the jobs were lost and none offset by transportation increases.

However, the above comparison does not take into account the time-value of money. The increased revenues would be fairly evenly distributed between 2016 and 2040, based on natural gas consumption. But a large portion of the increased costs are from pipeline infrastructure investments, which will all assumed to be incurred by 2020. This means that these infrastructure costs have a larger impact on the NPV of the shortfall. The total sum of this shortfall is also increased when amortizing the shortfall over a 25 year period, to establish the annual value that would reduce consumer spending in order to finance the pipeline expansion.

This shortfall could be covered in different ways, including rate modification, expansion surcharge fees, government support, etc. Either way, the shortfall has been counted as a negative to consumer spending, since even a government subsidy would need to be repaid through taxes on consumers. The inclusion of the shortfall in this way allows the study to show the net economic impacts for the Canadian economy, while remaining undecided regarding potential funding sources.

Consumer Spending
The increase in consumer spending is taken from the customer impact calculations, where it is derived from the fuel cost savings, net equipment purchase expenditures, and increased expansion surcharge customer fees. Before modeling the economic impacts, the consumer spending is also decreased by the annualized distributor shortfall, as discussed above.

Government Revenues
Government tax and revenue impacts were estimated based on the GDP impacts from the economic model, using historical ratios of GDP to government revenue. Government revenue was estimated to increase by a total of 35.8% of GDP. This is based on contributions of 14.4% for the federal government[50], 17.7% for provincial governments[51], and 3.7% for municipal governments.[51]

General Assumptions

Some other general assumptions that are important to the results of this study include:

- **Discount Rate:** A discount rate of 5.5% was used throughout this study, based on average values used in planning by the CGA's membership.

- **Study Period:** The study considers the 2016 to 2040 timeframe, and benefits are captured from equipment installation up until the end of the study period.

- **Exchange Rate:** In the select instances where currency conversions were required, which was in conjunction with benchmark prices used in the NEB fuel price forecast, the corresponding USD/CAD exchange rates from the NEB study's 'low price scenario' were used, to maintain consistency.[52]

[50] Department of Finance, Annual Financial Report of the Government of Canada, Fiscal Year 2013–2014. http://www.fin.gc.ca/afr-rfa/2014/report-rapport-eng.asp
[51] Calculated from Statistics Canada, CANSIM, tables 385-0024 and 385-0001
[52] National Energy Board, Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035, 2013.

IMPLAN Background

The following section provides a brief overview of the IMPLAN model. The economic modeling was conducted using IMPLAN v.3.1 model and 2012 data. IMPLAN is a static input-output model that is extensively used to analyze the economic impacts of any infrastructure development scenario, including various energy infrastructure improvement scenarios. The impacts produced by IMPLAN can be assessed annually and job impacts can be reported in annual job-years. The baseline data used (i.e., multipliers) are for a snapshot/historical year, in this case 2012, and hence projected results for future years are an approximation based on historical relationships.

The IMPLAN modeling framework used by ICF consists of two components – the descriptive model and the predictive model. The descriptive model defines the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region". It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region. In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments. The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. These multipliers are thus coefficients that "describe the response of the (local) economy to a stimulus (a change in demand or production)."

Three types of multipliers are used in IMPLAN:

- **Direct** – represents the impacts (e.g., employment or output changes) due to the direct changes being modeled, such as the higher demand for goods and services for the directly affected sectors, which benefit from the additional spending from the reduced energy costs.
- **Indirect** – represents the impacts due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands. These are commonly referred to as the "upstream" impacts.
- **Induced** – represents the impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

One of the biggest advantages of IMPLAN is the finer level of sectoral detail than is available in other competing models. The latest version of the Canadian IMPLAN model provides data on 103 industry sectors, including several institutional sectors such as households by income categories and various government sectors (federal, provincial, and local). These industry sectors are based on the North American Industry Classification System (NAICS). The detailed breakdown of the impacts by sector allows the user to analyze impacts specific to individual sectors of interest.

There are two main types of impact results that are often reported from IMPLAN – changes in value added output and employment. IMPLAN can also model impacts in labour income.

- **Total Value Added** – represents the commonly used metric for measuring economic output for a given scenario. It represents a "catch-all" for payments made by individual industry sectors to workers, interests, profits, and indirect business taxes. These are commonly referred to as "Gross Domestic Product" (GDP) impacts.
- **Employment** – represents the jobs supported by industry, based on the output per worker and output impacts for each industry.
- **Labour Income** – is part of the value added, and consists of all forms of employment income. Consistent with I/O terminology, IMPLAN defines this as the sum of the employee compensation and proprietor's income.

Appendix B Provincial Fuel Cost Savings

The annual fuel cost savings for Ontario, British Columbia, Manitoba, and Quebec are presented in Exhibit 30, Exhibit 31, Exhibit 32, and Exhibit 33, respectively.

Exhibit 30 Ontario - Annual Fuel Cost Savings of New Customers ($ Million)

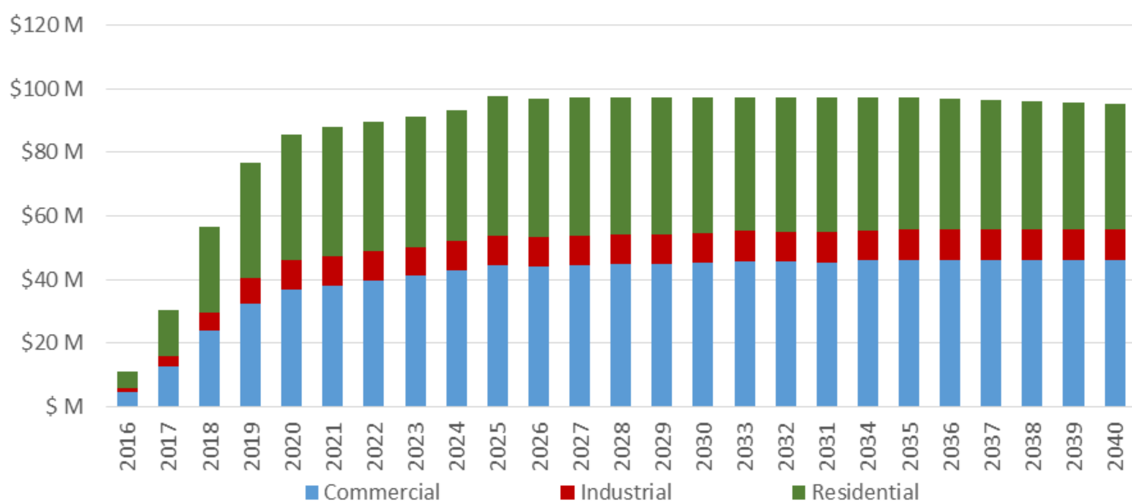


Exhibit 31 British Columbia - Annual Fuel Cost Savings of New Customers ($ Million)

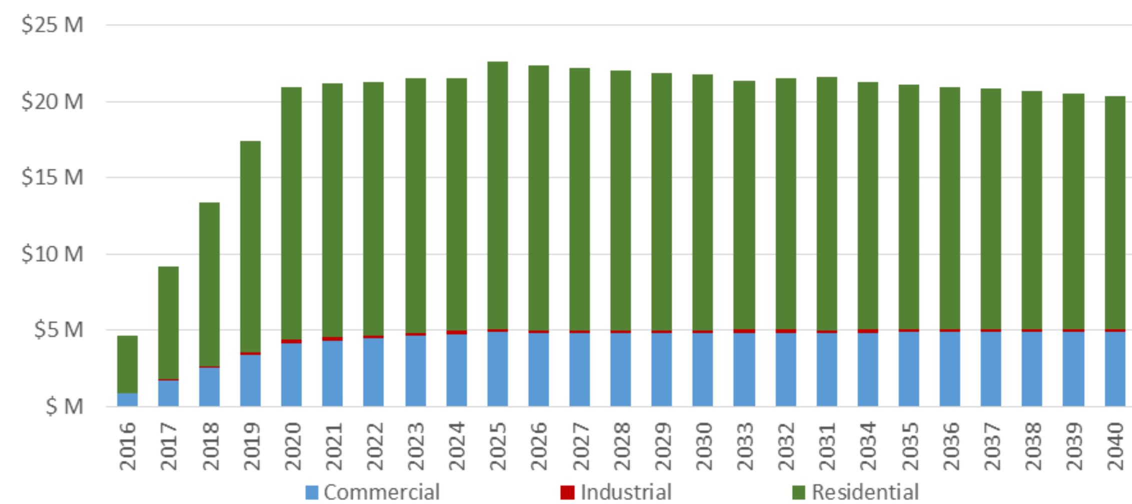


Exhibit 32 Manitoba - Annual Fuel Cost Savings of New Customers ($ Million)

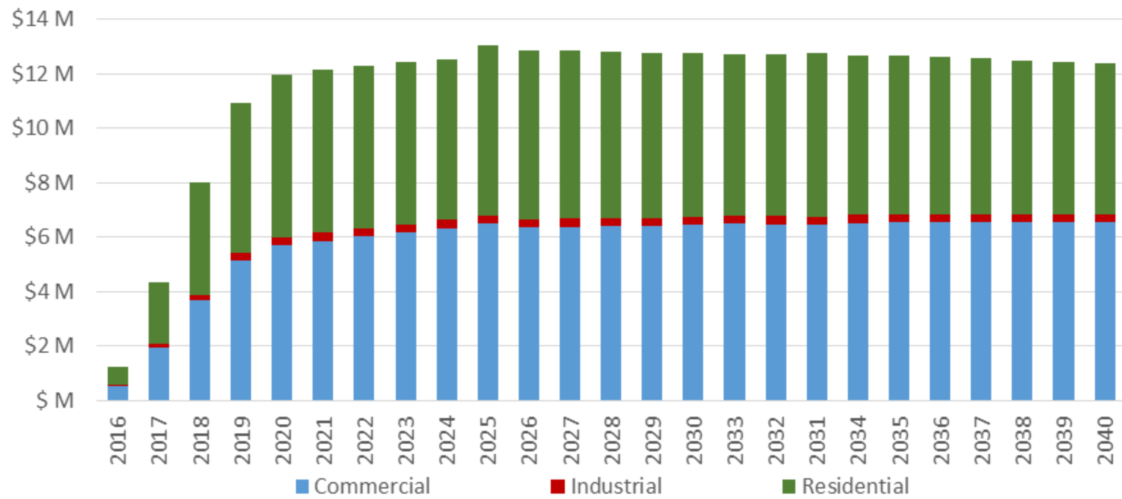
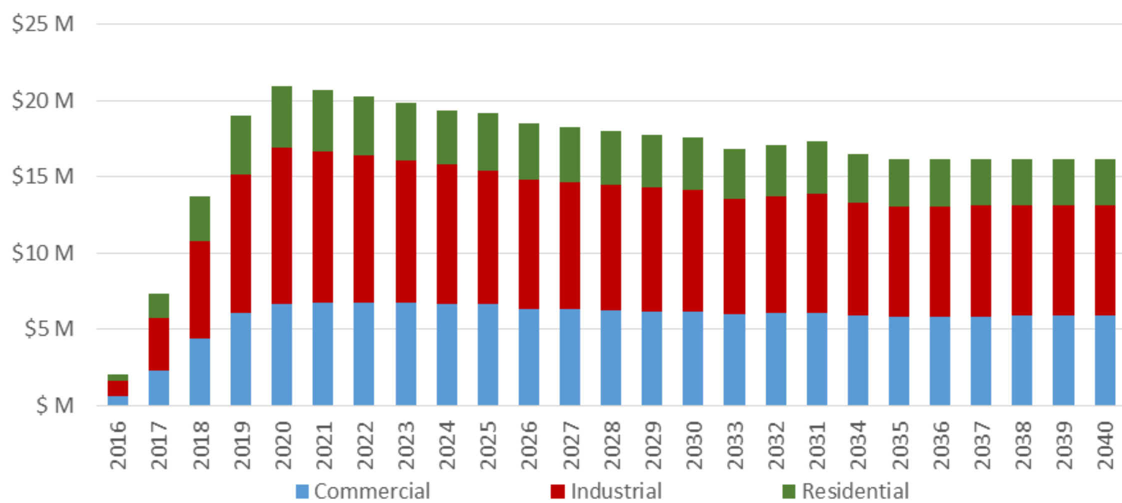


Exhibit 33 Quebec - Annual Fuel Cost Savings of New Customers ($ Million)



ICF INTERNATIONAL

PASSION. EXPERTISE. RESULTS.

icfi.ca

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 10

Please provide the assumptions used to determine that the price advantage of using natural gas over the lowest cost alternative energy has increased from $600 annually in 2006 to $1,680 in 2015. Please include all detailed calculations.

Response:

Figure 1 at Exhibit A, Tab 1, p. 9 is based on April 2015 Union cost comparisons including all volumetric and fixed charges appearing on consumer energy bills, with data sourced from The Kent Group for propane and heating oil (rates for London and Thunder Bay); Board time of use rates and utility specific charges for electricity (rates for London and Thunder Bay); and Union rate schedules. Annual energy costs are based on 2,200 m^3 (or 82 GJ) of residential consumption for home heating and water heating.

In 2006, the estimated annual cost of using natural gas was approximately $1,200, or approximately $600 lower than the estimated annual cost of propane or heating oil.

In 2015, the estimated annual cost of using natural gas is approximately $850, or approximately $1,680 lower than the estimated annual cost of propane or heating oil.

Please see the response at Exhibit B.CPA.1 a) i) for details on these comparisons.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, pp. 10-11

The evidence states that a typical conversion customer will have a return on initial investment within approximately four years, with energy cost savings beyond year four ($10,000 - $18,000 over 10 years). With a relatively short payback period, why in Union's view, should these customers be subsidized?

Response:

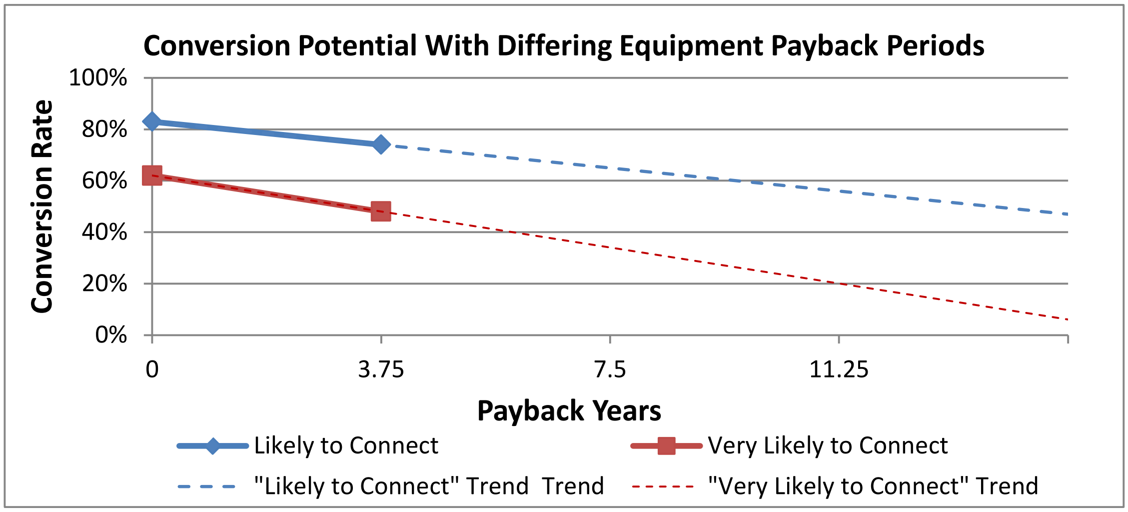
A four year pay-back period is a reasonable period. Most customers would be reluctant to make major purchase decisions for items of this nature with a longer payback period.

Aside from any general reluctance to make purchase decisions with longer payback periods, Union would be concerned that a lengthier payback period would deter homeowners from converting if they suspect they may be selling their house in the near-term.

Homeowners in Ontario spend an average of 16 years in their home[1]. Approximately 57% of non-customers without access to natural gas have already been in their home for 10 or more years[2]. Given the above, setting the payback at four years ensures that most homeowners can expect to see their investment paid-back before they move.

Union tested implications of the TES, albeit at a slightly lower level ($450/year) in third party community surveys for the communities of Milverton, Prince Township, and Lambton Shores. The results indicated that 74% of customers were likely to connect to the system with a TES in place. This compares to 83% likelihood if the TES was not in place. This decline demonstrates a level of price sensitivity amongst potential customers with regards to the payback period on their capital investment. By extrapolating these simple results, it would appear that extending the payback period by even a couple of years would significantly affect conversion rates and the resulting project economics, which becomes apparent in chart below.

[1] Source: Focus Canada 2012, released by the Environics Institute for Survey Research
[2] Union Gas 2011 Market Share Study, focussed on non-gas residential consumers residing in area codes in which natural gas infrastructure exists provided at Exhibit B.SEC.9, Attachment 1, p. 13.


Conversion Potential With Differing Equipment Payback Periods
Conversion Rate
100%
80%
60%
40%
20%
0%
0
3.75
7.5
11.25
Payback Years
Likely to Connect
Very Likely to Connect
"Likely to Connect" Trend Trend
"Very Likely to Connect" Trend

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 14

Please explain, in detail, how Union determined that it could complete 30 projects under its proposed program.

Response:

The Opportunity Assessment was conducted to understand the potential magnitude of Projects that might become feasible under various forms of regulatory flexibility. The list of potential Projects filed at Exhibit A, Tab 1, Appendix D, and the potential rate impacts of 30 Projects filed at Exhibit A, Tab 1, Appendices L and M were included to inform the Board of the potential magnitude and associated potential ratepayer impacts of a broad Community Expansion program. As noted at Exhibit B.CCC.3, Union is not at this time applying for approval to proceed with the construction of Projects beyond the first five[1] identified and detailed in Exhibit A, Tab 2.

To develop feasibility estimates for the Projects, Union applied a series of high level assumptions related to key economic modelling inputs. A summary of the assumptions underlying the assessment is included at Exhibit A, Tab 1, Appendix D. Additional detail is provided at Exhibit B.SEC.15.

To determine which Projects might be feasible, Union set the term of the TES and ITE to be a minimum of four years and a maximum of 10 years, and set minimum P.I. level to 0.4. The resulting Aid-to-Construction ("CIAC") requirement for each Project is provided in Exhibit A, Tab 1, Appendix D, in the columns labelled "Including TES/ITE, Min P.I. = 0.4, CIAC Required". If a Project did not require Aid-to-Construction, then it could be feasible under Union's Community Expansion proposal.

A total of 30 Projects were identified at a P.I. 0.4 that could be completed with the collection of a TES and ITE for a period of 10 years or less. For these Projects, no additional Aid-to-Construction was required.

---

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 18

Union is proposing that the Temporary Expansion Surcharge (TES) be set at $0.23 per m^3. Would this change over time or would it be set for the term of the five proposed projects? If natural gas prices increase will the TES be affected? Would the TES be different for future projects? What other factors might impact the TES going forward?

Response:

Union is proposing that the TES rate not be changed over the term of each project, and the $0.23 per m^3 be the same for any future projects. No other factors would affect the TES going forward.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 22

Union is proposing a municipal contribution mechanism to provide municipalities with a mechanism to contribute toward project feasibility. The Incremental Tax Equivalent (ITE) will be based on the estimated value of incremental property taxes collected from Union as a result of the project for a period of time that matches the term of the TES. Please indicate whether Union considered other mechanisms to obtain contributions from municipalities. If Union did consider alternatives why were they rejected? Why has Union determined that this mechanism results in the appropriate level of contribution from the municipalities? Has Union consulted with the municipalities to determine how much they are willing to contribute to each project? If not, why not? If so, please provide details of those discussions.

Response:

Union considered up front Aid-to-Construction contributions from the municipalities. The mechanism was rejected after various consultations with a number of municipalities and municipal associations. In those discussions, the municipalities indicated that they did not have the financial capacity to directly support Aid-to-Construction. Many of these municipalities are smaller rural communities with generally small tax bases, and significant Aid-to-Construction payments are unaffordable for them.

Union consulted on the ITE proposal, and found that most municipalities were willing to accept this level of contribution. It should be noted that this acceptance is despite the fact that the municipalities do not keep 100% of the property tax assessed against the pipeline systems. Some of that assessment flows to upper tier municipalities, and the educational component of the assessment flows back to the Province. The municipalities have been generally willing to accept the concept of paying Union more than they end up keeping from the incremental property tax assessment, because they recognize that any municipal owned buildings will receive the benefit of energy savings as well.

To test the concept, Union spoke with the municipal leaders for the five Projects being proposed as part of this Application[1], as well as with the municipal leaders from almost every one of the other 25 potential Projects. In addition, over the past several years Union has presented the concept at a number of municipal association meetings, including the Rural Ontario Municipal Association, the Northwestern Ontario Municipal Association, the Federation of Northern

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

Ontario Municipalities, and the Association of Municipalities of Ontario Board of Directors. Feedback from these discussions was supportive, and a number of various associations and municipalities have passed resolutions in support of Union's proposal concepts, including the ITE. In addition, a number of letters of support were forwarded to the Board and are posted on the Board's RESS for this proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, pp. 22-23

For each proposed project what is the proposed ITE amount? What is the total cost of each project? Please confirm that for each project that requires an ITE contribution because the PI is less then .8, the project will not go ahead unless and until Union obtains agreement from the relevant municipality to make the required ITE contribution. If not confirmed, please explain how Union proposes the shortfall resulting the failure to obtain an ITE related contribution would be funded?

Response:

Please see the response at Exhibit B.LPMA.16 for the proposed ITE amounts.

Union confirms that a Project to service a community in a single municipality will not proceed at a P.I. lower than 0.8 unless the municipality formally agrees to make either the ITE payments, or an equivalent up-front Aid-to-Construction payment.

In cases where a new supply main must pass through one municipality in order to provide service to the project targeted community, which is in a different municipality, the municipality in which the targeted community exists will be required to pay the ITE, or an equivalent up-front Aid-to-Construction payment.

If a Project will provide service to several communities within several municipalities or First Nations, Union will ensure that the municipalities in which both targeted communities lie formally commit to the ITE or an equivalent up-front Aid-to-Construction payment. Failure of one of the municipalities to commit will result in one part of the Project performed at a minimum P.I. of 0.8 (the municipality that hasn't agreed to the ITE), and the other part at a minimum P.I. of 0.4 (the municipality that has agreed to the ITE). Union's proposal for Kettle Point/Lambton Shores[1] reflects this scenario.

In the absence of a formal commitment to pay the ITE, the Project will be required to meet a minimum P.I. of 0.8.

---

[1] Exhibit A, Tab 2, Section A

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 27

The required minimum PI for contract customers will be the same as the minimum PI set for the Community Expansion Project. Where the PI for the customer connection is less than the Community Expansion Project PI, the contract customer will contribute to a level to reach the project PI. How are the rest of the contract customer site specific costs funded?

Response:

Union proposes that the capital costs to connect a contract customer to a Community Expansion project include two components; site specific costs and incremental common costs to the adjacent Community Expansion Project.

Site specific capital costs to connect a contract customer to the natural gas system will be funded directly by the contract customer, either through a combination of contract rate, minimum annual volume, or term, or through any necessary Aid-to-Construction. These capital costs include metering equipment at the contract customer site, the service from the main to the metering equipment, and any additional main that would not have been installed as part of the project to serve the adjacent community.

The incremental common project costs will include any cost for upsizing the system to service the incremental load represented by the contract customer, as well as any incremental reinforcement necessary in the pre-existing upstream system to provide necessary capacity.

The total of the site specific and incremental common project costs will be recovered from the contract customers to the point where the economic feasibility analysis of the contract addition meets the same P.I. as that of the Community Expansion Project it is being connected to. To the extent that the contract customer connection in this case will be at a P.I. of less than 1.0, existing ratepayers will fund the residual rate recovery.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 28

Union is proposing to fund the Community Expansion Program, in part through cross-subsidization by existing customers. What, in Union's view, are the benefits to those customers?

Response:

Please see the response at Exhibit B.CCC.5.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 31

Is it Union's view that this proposal is consistent with the 2014-2018 Incentive Regulation Mechanism Settlement Agreement?

Response:

Yes. Union's proposal is a direct response to the government's desire to complete the maximum number of Projects, and the Board's invitation to propose plans. The need for such a proposal was unknown at the time of Union's IRM framework approval, and is clearly material at $150 million of new capital investment. In Union's view its proposals are the first step in a broader program. With respect to the capital pass-through mechanism, the objective of the capital pass-through mechanism is to allow the utility to earn its allowed return, no more or less, during the incentive regulation term. Union's proposal is consistent with the approach approved under its IRM framework.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 33

Is it Union's intention (and are all of Union's subsequent rate impact calculations based on the intention) to distribute TES and ITE revenues to all customers, including both existing customers and newly attached customers from whom TES revenue is collected and who live in municipalities that contribute ITE revenue? If the former, does Union agree that as a result the intended mitigation of cross subsidization by collecting TES and RTE revenue is inappropriately muted by collecting the revenue from newly attached customers and their associated municipalities and then giving (a portion of) that revenue back to the same customers in rates? Please recalculate the bill impacts on existing customers at Appendix M on the assumption that RTE and TES revenue is allocated entirely to existing customers (if the original calculation was not done on that basis).

Response:

Yes, Union's proposal is to dispose of the balance in the Community Expansion Contribution Deferral Account to both existing and newly attached Union customers including Community Expansion customers.

The newly attached customers of the Community Expansion communities will pay the TES and will receive a credit for the TES and ITE through the disposition of the Community Expansion Contribution Deferral Account; however, the credit each customer receives will be significantly less than the TES paid. For example, a newly attached average Rate M1 residential customer in Union South consuming 2,200 m^3 per year will pay \$506 in TES (\$0.23 x 2,200 m^3) and may receive a credit of \$1.54 (Exhibit A, Tab 1, Appendix M, Updated, line 3) for the disposition of the Community Expansion Contribution Deferral Account for the 30 potential projects in 2018.

Allocating the balance in the Community Expansion Contribution Deferral Account to only existing customers results in bill impacts of (\$0.01) for a Rate M1 average residential customer and no change for a Rate 01 average residential customer consuming 2,200 m^3 annually.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 42

The Ontario Government announced that it would be making available $200 million in Natural Gas Access Loans and $30 million in Natural Gas Development Grants. When does Union expect that the criteria and funding form will be finalized? Why does Union limit the use of Natural Gas Access Loans and Natural Gas Economic Development Grants as aids-to construct only if received in advance of project construction?

Response:

Union is assuming that the criteria and funding form will be finalized in late 2016 or early 2017, in order to enable delivery of the program beginning in the Province's 2017-2018 fiscal year. This assumption is based on a timing diagram in the Ontario 2015 Budget[1].

Union's understanding, from dialogue with various provincial Ministries, is that they would expect Community Expansion Projects to exhaust any available regulatory flexibility before they would become eligible for provincial funding. Evidence of this can be found in a statement that the Minister of Economic Development, Employment and Infrastructure made to the Standing Committee on Estimates on November 17, 2015:

> *"…..We've got a grant program that we're looking at that can help in that respect as well that we'll be rolling out. It's still going to take some time because the first step had to be taken, and that was a step that the OEB had to take. Ideally, and if you talk to the sector they understand this, with more flexibility, Union Gas and Enbridge can do more and expand more, and they're willing to do it. The Minister of Energy has provided OEB with those directions, and that is now opening up some opportunities for expansion, so we can now work off of that to determine how much further we can go and where to make those investments[2]".*

Union assumed the grants and loans will be made to municipalities, and that the municipalities would in turn pay the actual Aid-to-Construction to Union. Alternatively the municipality might be able to direct the funding directly from the Province to Union. The fact that the government has publicly declared the funding as loans and grants implies they are received in their entirety

[1] http://www.fin.gov.on.ca/en/budget/ontariobudgets/2015/papers_all.pdf p. 54
[2] http://www.ontla.on.ca/web/committee-proceedings/committee_transcripts_details.do?locale=en&Date=2015-11-17&ParlCommID=8996&BillID=&Business=Ministry+of+Economic+Development%2C+Employment+and+Infrastructure&DocumentID=29793#para525

when approved, assuming typical government practice remains unchanged.

Union does not typically begin construction of a Project requiring Aid-to-Construction until such time as either the Aid-to-Construction is paid or a commercially binding agreement is in place to ensure an equivalent amount will be paid. This approach is consistent with Union's current practice.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, p. 43

How did Union decide which specific five projects to move forward with at this time?

Response:

The five[1] projects were selected based on a combination of their economic feasibility in the absence of Union's proposal, the degree of interest expressed by customers and/or municipal leaders of those communities, and an interest in supporting Ontario's First Nations communities.

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Has Union sought any Federal Government funding for its natural gas Community Expansion Project? If not, why was this not pursued? If so, please provide the details of any discussions Union has had with the Federal Government?

Response:

Union has supported the Canadian Gas Association in their advocacy for federal funding to support Community Expansion Projects. Union's understanding is that any financial support would likely come through regional federal funding agencies (e.g. FedNor). At this point municipalities can apply on a project by project basis if the criteria surrounding these federal programs are applicable to their specific circumstances.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 1, Appendix D

Within Union's Opportunity Assessment Summary what is the difference between "potential customers" and "forecast customers"? How were these numbers derived? Please explain how the annual volumes, gross capital cost, and gross capital/customer were derived?

Response:

The Opportunity Assessment was conducted only to understand the potential magnitude of Projects that might become feasible under various forms of regulatory flexibility. The list of potential Projects filed at Exhibit A, Tab 1, Appendix D, and the potential rate impacts of 30 Projects filed at Exhibit A, Tab 1, Appendices L and M were included to inform the Board of the potential magnitude and associated potential ratepayer impacts of a broad Community Expansion program. As noted in the response to Exhibit B.CCC.3, Union is not at this time applying for approval to proceed with construction of Projects beyond the first five identified and detailed in Exhibit A, Tab 2[1].

Union's approach to conducting the Opportunity Assessment is described in Exhibit A, Tab 1, Appendix D, pp. 4-5 and at Exhibit B.SEC.15.

Potential customers are the number of homes and businesses that might connect to Union's distribution system. Forecast customers are the number of customers predicted to connect to the system over the 10 year forecast period used in Union's economic feasibility assessments. Where better information was not available, Union assumed that 45% of the potential customers would connect to the system in this period. In these situations, the forecast customers equal 45% of the potential customers. This assumption is conservative, as outlined in the response at Exhibit B.South Bruce.6 c).

Gross capital per potential customer is the gross capital cost of the project divided by the number of potential customers who would gain access to the natural gas system.

---

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A, Tab 3, p. 3

Union is proposing a Temporary Connection Surcharge (TCS) \$0.23/m^3. For what period of time is Union seeking approval of the charge?

Response:

In each situation where the TCS is applied, the period of time will be the term required for the specific project to meet a P.I. of 1.0, subject to a maximum of 10 years.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Reference: Exhibit A / Tab 1 / Appendix K

The evidence shows costs of the 30 proposed projects being allocated across all of Union's existing rate classes, but it appears that bill impact calculations have only been provided (at Appendices L and M) for the M1 and 01 Rate classes. Please provide bill impacts for the remainder of the Rate Classes (or, alternatively, confirm that there is no rate impact or an immaterial rate impact for a rate class if that is the case and explain why that is the case). With respect to Appendix K, please split the total annual revenue requirement amount of $12,979,000 between the amount that, if the Board were not to approve the lowering of the PI from .8 to .4, would be appropriately included in rates, and the amount that is proposed to be included in rates on the basis of the lowering of the PI to .4. Please redraft Appendix K with column (a) split into two columns, the first showing the allocation of costs that would be normally recoverable in rate using a PI of .8, and a second column showing the incremental amount that can only be recovered in rates if Union is allowed to lower the PI to .4.

Response:

Please see Attachment 1 for the 2018 bill impacts for all rate classes of the 29 potential Community Expansion projects including the TES and ITE deferral credits.

Please see Attachment 2 for the 2018 cost allocation of the Community Expansion projects that achieve a PI of 0.8 separately identified from the cost allocation of the remaining projects. The projects that achieve a PI of 0.8 include Milverton, Chippewa's of Kettle and Stony Point First Nation and Lambton Shores and Delaware Nation of Moraviantown, as provided at Exhibit B.LPMA.13 d), Attachment 1. The total 2018 revenue requirement of $12.979 million has been updated to $11.399 million, as per Exhibit A, Tab 1, Appendix J, Updated.

UNION GAS LIMITED
Impacts of the Potential 29 Community Expansion Projects Including TES and ITE Deferral Credits
Calculation of 2018 Sales Service and Direct Purchase Impacts for Typical Small and Large Customers - Union North

Line No.	Particulars	EB-2015-0187 2015 Jul QRAM Rates (1) Bill ($) (a)	Unit Rate (cents/m^3) (b)	2015 Rates including Community Expansion in 2018 Bill ($) (c)	Unit Rate (cents/m^3) (d)	Impact Unit Rate (cents/m^3) (e) = (d-b)	Delivery Rate Change ($) (f) = (c-a)	Bill (%) (g) = (f/a)
	Small Rate 01							
1	Delivery Charges	447	20.3307	448	20.3659	0.0352	0.77	0.2%
2	Gas Supply Charges	542	24.6490	542	24.6463	(0.0027)	(0.06)	0.0%
3	Total Bill	990	44.9797	990	45.0122	0.0325	0.71	0.1%
4	Sales Service Impact						0.71	0.1%
5	Bundled-T (Direct Purchase) Impact						0.71	0.1%
	Small Rate 10							
6	Delivery Charges	4,493	7.4877	4,593	7.6544	0.1667	100.01	2.2%
7	Gas Supply Charges	14,789	24.6490	14,788	24.6463	(0.0027)	(1.63)	0.0%
8	Total Bill	19,282	32.1367	19,380	32.3007	0.1640	98.38	0.5%
9	Sales Service Impact						98.38	0.5%
10	Bundled-T (Direct Purchase) Impact						98.38	0.8%
	Large Rate 10							
11	Delivery Charges	14,507	5.8027	14,744	5.8976	0.0949	237.21	1.6%
12	Gas Supply Charges	61,623	24.6490	61,616	24.6463	(0.0027)	(6.78)	0.0%
13	Total Bill	76,129	30.4518	76,360	30.5439	0.0922	230.43	0.3%
14	Sales Service Impact						230.43	0.3%
15	Bundled-T (Direct Purchase) Impact						230.43	0.5%
	Small Rate 20							
16	Delivery Charges	74,678	2.4893	76,523	2.5508	0.0615	1,844.89	2.5%
17	Gas Supply Charges	657,718	21.9239	657,646	21.9215	(0.0024)	(72.58)	0.0%
18	Total Bill	732,396	24.4132	734,169	24.4723	0.0591	1,772.32	0.2%
19	Sales Service Impact						1,772.32	0.2%
20	Bundled-T (Direct Purchase) Impact						2,293.87	0.6%
	Large Rate 20							
21	Delivery Charges	286,266	1.9084	290,901	1.9393	0.0309	4,634.71	1.6%
22	Gas Supply Charges	3,081,424	20.5428	3,081,113	20.5408	(0.0021)	(311.05)	0.0%
23	Total Bill	3,367,690	22.4513	3,372,013	22.4801	0.0288	4,323.66	0.1%
24	Sales Service Impact						4,323.66	0.1%
25	Bundled-T (Direct Purchase) Impact						4,323.66	0.3%
	Average Rate 25							
26	Delivery Charges	63,539	2.7929	64,848	2.8505	0.0575	1,308.60	2.1%
27	Gas Supply Charges	368,650	16.2044	368,650	16.2044	-	-	0.0%
28	Total Bill	432,189	18.9973	433,498	19.0548	0.0575	1,308.60	0.3%
29	Sales Service Impact						1,308.60	0.3%
30	T-Service (Direct Purchase) Impact						1,308.60	2.1%
	Small Rate 100							
31	Delivery Charges	261,451	0.9683	266,701	0.9878	0.0194	5,249.63	2.0%
32	Gas Supply Charges	6,150,989	22.7814	6,150,989	22.7814	-	-	0.0%
33	Total Bill	6,412,440	23.7498	6,417,690	23.7692	0.0194	5,249.63	0.1%
34	Sales Service Impact						5,249.63	0.1%
35	T-Service (Direct Purchase) Impact						5,249.63	2.0%
	Large Rate 100							
36	Delivery Charges	2,113,543	0.8806	2,151,336	0.8964	0.0157	37,793.41	1.8%
37	Gas Supply Charges	53,570,299	22.3210	53,570,299	22.3210	-	-	0.0%
38	Total Bill	55,683,842	23.2016	55,721,636	23.2173	0.0157	37,793.41	0.1%
39	Sales Service Impact						37,793.41	0.1%
40	T-Service (Direct Purchase) Impact						37,793.41	1.8%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's 2015 Rate Order filing (EB-2015-0187).

UNION GAS LIMITED
Impacts of the Potential 29 Community Expansion Projects Including TES and ITE Deferral Credits
Calculation of Sales Service and Direct Purchase Impacts for Typical Small and Large Customers - Union South

		EB-2015-0187 2015 Jul QRAM Rates (1)		2015 Rates including Community Expansion in 2018		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M1							
1	Delivery Charges	350	15.8925	353	16.0406	0.1481	3.26	0.9%
2	Gas Supply Charges	357	16.2455	357	16.2455	-	-	0.0%
3	Total Bill	707	32.1380	710	32.2861	0.1481	3.26	0.5%
4	Sales Service Impact						3.26	0.5%
5	Direct Purchase Impact						3.26	0.9%
	Small Rate M2							
6	Delivery Charges	3,343	5.5714	3,397	5.6614	0.0900	54.01	1.6%
7	Gas Supply Charges	9,747	16.2455	9,747	16.2455	-	-	0.0%
8	Total Bill	13,090	21.8169	13,144	21.9069	0.0900	54.01	0.4%
9	Sales Service Impact						54.01	0.4%
10	Direct Purchase Impact						54.01	1.6%
	Large Rate M2							
11	Delivery Charges	10,801	4.3205	10,973	4.3894	0.0689	172.23	1.6%
12	Gas Supply Charges	40,614	16.2455	40,614	16.2455	-	-	0.0%
13	Total Bill	51,415	20.5660	51,587	20.6349	0.0689	172.23	0.3%
14	Sales Service Impact						172.23	0.3%
15	Direct Purchase Impact						172.23	1.6%
	Small Rate M4							
16	Delivery Charges	36,618	4.1850	37,283	4.2610	0.0760	664.94	1.8%
17	Gas Supply Charges	142,148	16.2455	142,148	16.2455	-	-	0.0%
18	Total Bill	178,767	20.4305	179,432	20.5065	0.0760	664.94	0.4%
19	Sales Service Impact						664.94	0.4%
20	Direct Purchase Impact						664.94	1.8%
	Large Rate M4							
21	Delivery Charges	284,379	2.3698	288,722	2.4060	0.0362	4,343.04	1.5%
22	Gas Supply Charges	1,949,460	16.2455	1,949,460	16.2455	-	-	0.0%
23	Total Bill	2,233,839	18.6153	2,238,182	18.6515	0.0362	4,343.04	0.2%
24	Sales Service Impact						4,343.04	0.2%
25	Direct Purchase Impact						4,343.04	1.5%
	Small Rate M5							
26	Delivery Charges	30,072	3.6451	31,327	3.7972	0.1522	1,255.50	4.2%
27	Gas Supply Charges	134,025	16.2455	134,025	16.2455	-	-	0.0%
28	Total Bill	164,097	19.8906	165,353	20.0427	0.1522	1,255.50	0.8%
29	Sales Service Impact						1,255.50	0.8%
30	Direct Purchase Impact						1,255.50	4.2%
	Large Rate M5							
31	Delivery Charges	164,701	2.5339	173,599	2.6708	0.1369	8,897.96	5.4%
32	Gas Supply Charges	1,055,958	16.2455	1,055,958	16.2455	-	-	0.0%
33	Total Bill	1,220,659	18.7794	1,229,556	18.9163	0.1369	8,897.96	0.7%
34	Sales Service Impact						8,897.96	0.7%
35	Direct Purchase Impact						8,897.96	5.4%
	Small Rate M7							
36	Delivery Charges	644,105	1.7892	648,100	1.8003	0.0111	3,994.90	0.6%
37	Gas Supply Charges	5,848,380	16.2455	5,848,380	16.2455	-	-	0.0%
38	Total Bill	6,492,485	18.0347	6,496,480	18.0458	0.0111	3,994.90	0.1%
39	Sales Service Impact						3,994.90	0.1%
40	Direct Purchase Impact						3,994.90	0.6%
	Large Rate M7							
41	Delivery Charges	2,451,861	4.7151	2,489,017	4.7866	0.0715	37,155.81	1.5%
42	Gas Supply Charges	8,447,660	16.2455	8,447,660	16.2455	-	-	0.0%
43	Total Bill	10,899,521	20.9606	10,936,677	21.0321	0.0715	37,155.81	0.3%
44	Sales Service Impact						37,155.81	0.3%
45	Direct Purchase Impact						37,155.81	1.5%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's 2015 Rate Order filing (EB-2015-0187).

UNION GAS LIMITED
Impacts of the Potential 29 Community Expansion Projects Including TES and ITE Deferral Credits
Calculation of Sales Service and Direct Purchase Impacts for Typical Small and Large Customers - Union South

		EB-2015-0187 2015 Jul QRAM Rates (1)		2015 Rates including Community Expansion in 2018		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M9							
1	Delivery Charges	124,052	1.7849	124,014	1.7844	(0.0005)	(37.54)	0.0%
2	Gas Supply Charges	1,129,062	16.2455	1,129,062	16.2455	-	-	0.0%
3	Total Bill	1,253,114	18.0304	1,253,076	18.0299	(0.0005)	(37.54)	0.0%
4	Sales Service Impact						(37.54)	0.0%
5	Direct Purchase Impact						(37.54)	0.0%
	Large Rate M9							
6	Delivery Charges	368,423	1.8259	368,318	1.8253	(0.0005)	(105.94)	0.0%
7	Gas Supply Charges	3,278,017	16.2455	3,278,017	16.2455	-	-	0.0%
8	Total Bill	3,646,440	18.0714	3,646,335	18.0708	(0.0005)	(105.94)	0.0%
9	Sales Service Impact						(105.94)	0.0%
10	Direct Purchase Impact						(105.94)	0.0%
	Average Rate M10							
11	Delivery Charges	5,121	5.4191	5,156	5.4558	0.0367	34.70	0.7%
12	Gas Supply Charges	15,352	16.2455	15,352	16.2455	-	-	0.0%
13	Total Bill	20,473	21.6646	20,508	21.7013	0.0367	34.70	0.2%
14	Sales Service Impact						34.70	0.2%
15	Direct Purchase Impact						34.70	0.7%
	Small Rate T1							
16	Delivery Charges	129,998	1.7248	131,962	1.7509	0.0261	1,964.19	1.5%
17	Gas Supply Charges	1,224,423	16.2455	1,224,423	16.2455	-	-	0.0%
18	Total Bill	1,354,421	17.9703	1,356,385	17.9964	0.0261	1,964.19	0.1%
19	Sales Service Impact						1,964.19	0.1%
20	Direct Purchase Impact						1,964.19	1.5%
	Average Rate T1							
21	Delivery Charges	198,345	1.7149	201,547	1.7426	0.0277	3,201.44	1.6%
22	Gas Supply Charges	1,878,944	16.2455	1,878,944	16.2455	-	-	0.0%
23	Total Bill	2,077,290	17.9604	2,080,491	17.9881	0.0277	3,201.44	0.2%
24	Sales Service Impact						3,201.44	0.2%
25	Direct Purchase Impact						3,201.44	1.6%
	Large Rate T1							
26	Delivery Charges	437,508	1.7074	445,044	1.7368	0.0294	7,536.96	1.7%
27	Gas Supply Charges	4,162,760	16.2455	4,162,760	16.2455	-	-	0.0%
28	Total Bill	4,600,267	17.9529	4,607,804	17.9823	0.0294	7,536.96	0.2%
29	Sales Service Impact						7,536.96	0.2%
30	Direct Purchase Impact						7,536.96	1.7%
	Small Rate T2							
31	Delivery Charges	494,864	0.8351	497,322	0.8393	0.0041	2,457.76	0.5%
32	Gas Supply Charges	9,626,433	16.2455	9,626,433	16.2455	-	-	0.0%
33	Total Bill	10,121,298	17.0806	10,123,756	17.0848	0.0041	2,457.76	0.0%
34	Sales Service Impact						2,457.76	0.0%
35	Direct Purchase Impact						2,457.76	0.5%
	Average Rate T2							
36	Delivery Charges	1,141,889	0.5773	1,143,227	0.5780	0.0007	1,338.27	0.1%
37	Gas Supply Charges	32,131,950	16.2455	32,131,950	16.2455	-	-	0.0%
38	Total Bill	33,273,839	16.8228	33,275,177	16.8235	0.0007	1,338.27	0.0%
39	Sales Service Impact						1,338.27	0.0%
40	Direct Purchase Impact						1,338.27	0.1%
	Large Rate T2							
41	Delivery Charges	1,860,652	0.5028	1,860,242	0.5026	(0.0001)	(409.93)	0.0%
42	Gas Supply Charges	60,122,808	16.2455	60,122,808	16.2455	-	-	0.0%
43	Total Bill	61,983,460	16.7483	61,983,050	16.7481	(0.0001)	(409.93)	0.0%
44	Sales Service Impact						(409.93)	0.0%
45	Direct Purchase Impact						(409.93)	0.0%
	Large Rate T3							
46	Delivery Charges	3,220,759	1.1810	3,217,745	1.1799	(0.0011)	(3,014.75)	-0.1%
47	Gas Supply Charges	44,303,428	16.2455	44,303,428	16.2455	-	-	0.0%
48	Total Bill	47,524,187	17.4265	47,521,173	17.4254	(0.0011)	(3,014.75)	0.0%
49	Sales Service Impact						(3,014.75)	0.0%
50	Direct Purchase Impact						(3,014.75)	-0.1%

Notes:
(1) Reflects Board-approved rates per Appendix A in Union's 2015 Rate Order filing (EB-2015-0187).

UNION GAS LIMITED
2018 Cost Allocation of the Potential 29 Community Expansion Projects

Line No.	Particulars ($000's)	Project Costs: Projects with a Minimum PI of 0.8	Project Costs: Remaining Projects	Total 2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d)	(e)	(f) = (c + d + e)
1	Rate M1	568	5,805	6,373	(1,765)	(288)	4,320
2	Rate M2	97	1,061	1,158	(321)	(50)	788
3	Rate M4	27	290	317	(88)	(14)	215
4	Rate M5	37	407	443	(123)	(12)	309
5	Rate M7	7	72	79	(22)	(4)	53
6	Rate M9	0	0	0	(0)	(1)	(0)
7	Rate M10	0	0	0	(0)	(0)	0
8	Rate T1	18	199	218	(60)	(11)	147
9	Rate T2	28	277	305	(84)	(44)	177
10	Rate T3	(0)	(1)	(1)	0	(5)	(5)
11	Subtotal - Union South	782	8,111	8,893	(2,463)	(427)	6,002
12	Excess Utility Space	(0)	(7)	(8)	2	(2)	(7)
13	Rate C1	(0)	(3)	(3)	1	(2)	(4)
14	Rate M12	(6)	(194)	(201)	56	(160)	(306)
15	Rate M13	(0)	(0)	(0)	0	(0)	(0)
16	Rate M16	(0)	(0)	(0)	0	(0)	(1)
17	Subtotal - Ex-franchise	(7)	(205)	(212)	59	(164)	(318)
18	Rate 01	(47)	1,474	1,427	(395)	(121)	911
19	Rate 10	(8)	472	463	(128)	(19)	316
20	Rate 20	(8)	346	338	(94)	(14)	231
21	Rate 100	(6)	402	396	(110)	(12)	275
22	Rate 25	(2)	96	94	(26)	(4)	64
23	Subtotal - Union North	(71)	2,789	2,719	(753)	(170)	1,796
24	In-franchise	711	10,900	11,611	(3,216)	(597)	7,798
25	Ex-franchise	(7)	(205)	(212)	59	(164)	(318)
26	Total	704	10,695	11,399	(3,157)	(762)	7,480

Notes:
(1) 2018 project costs associated with 29 potential community expansion projects, as per Exhibit A, Tab 1, Appendix K, column (a), Updated.
(2) TES credit allocated to rate classes in proportion to column (c)
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Has Union undertaken any customer engagement activities with respect to its proposed Community Expansion program? Specifically, has Union asked its current customers if they are willing to subsidize new expansions? If not, why not? If so, please provide the results of that research.

Response:

Union has not undertaken research to determine if current customers are willing to subsidize new expansions. Union's proposal is a direct response to the government's desire to complete the maximum number of Projects, and the Board's invitation to propose plans. Union has in turn applied its experience, judgment and regulatory precedent, to limit the impact on ratepayers to a maximum of $2 per month. The precedent referenced is the framework issued by the Board in 2014 which stated that the annual cost impact of Union's DSM programs be limited to a maximum of $2 per month for a typical residential ratepayer[1]. Union's proposal to limit the maximum ratepayer impact of a Community Expansion Program is consistent with this figure.

The annual cost impacts for the 30 potential projects, which range from $3.88 to $5.64 per year for a typical Union South residential ratepayer, represent less than 1% of the total amount billed. Even at the maximum proposed rate impact of $24 per year, ratepayers would still have annual natural gas bills that are lower than they were 15 years ago, despite inflation of 25%[2] over that period.

[1] EB 2014-0134 Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 17, http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf
[2] Based on a rate of 1.5% per year.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1

Union presents figures, tables, and survey results without providing the data and documents on which they are based. CPA is, therefore, unable to test those figures, tables, and survey results.

a) Provide complete underlying data, calculations, assumptions, source documents, survey questions, survey results, identities of survey participants and persons Union attempted to survey, as applicable, for the following:

i) Figure 1 at page 9
ii) Figure 2 at page 10
iii) Table 1 at page 18
iv) Table 2 at page 19
v) Survey referenced at page 20
vi) Figure 4 at page 25
vii) Table 3 at page 26
viii) Table 8 at page 45
ix) Appendix D
x) Survey at Exhibit "A", Tab 2, Section "A", page 4, paras. 18 and 19
xi) Survey at Exhibit "A", Tab 2, Section "B", page 4, paras. 18 and 19 (to the extent that it differs from the survey referenced at page 20)
xii) Survey at Exhibit "A", Tab 2, Section "C", page 4, paras. 16 and 17
xiii) Survey at Exhibit "A", Tab 2, Section "D", page 4, paras. 16 and 17
xiv) Survey at Exhibit "A", Tab 2, Section "E", page 4, paras. 16 to 18

Response:

a)

i) Please see Attachment 1.

ii) Please see Attachment 2.

iii) Annual savings in this table are from i) above (please see Attachment 1). Penetration is sourced from 2011 Market Share Survey (please see the response at Exhibit B.SEC.9).

iv) Penetration is sourced from 2011 Market Share Survey, referenced in a) iii) above. Estimated conversions costs for differing equipment types is from various undocumented verbal conversations with several heating, ventilation and air conditioning contractors.

v) Please see the response at Exhibit B.Staff.11, Attachment 2 and 3.

vi) Please see the response at Exhibit B.CPA.13.

vii) The source of this data is Exhibit A, Tab 1, Appendix D, pp. 1-3.

viii) For information regarding the customer potential and forecast, please see the response at Exhibit B.Staff.11. For information on capital costs please see the Cost Schedules attached to the specific projects at Exhibit A, Tab 2. For information on P.I.'s, TES and ITE, please see the individual project DCF's attached to the specific projects.

ix) The relevant information for the four projects Union is seeking approval for is in their respective Sections of Exhibit A, Tab 2. Please also see the response at Exhibit B.CCC.19.

x) Please see the response at Exhibit B.Staff.11.

xi) Please see the response at Exhibit B.Staff.11.

xii) Union staff completed on-site surveys to determine the potential customers in the Delaware Nation of Moraviantown.

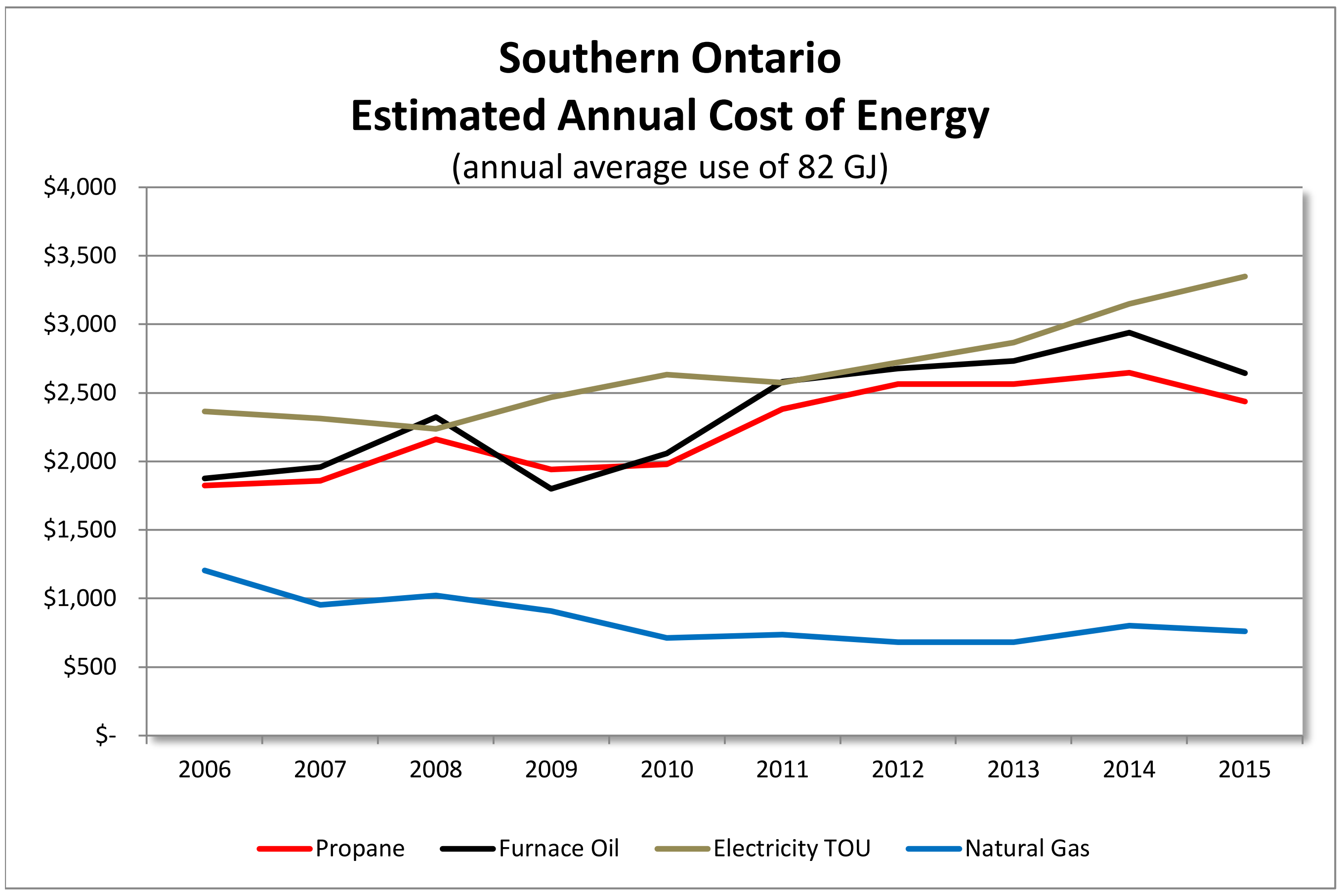
xiii) Please see the response at Exhibit B.Staff.11.

xiv) Not applicable[1].

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

Southern Ontario Estimated Annual Cost of Energy

Year	Propane	Furnace Oil	Electricity TOU	Natural Gas
2006	$ 1,823	$ 1,875	$ 2,364	$ 1,203
2007	$ 1,857	$ 1,959	$ 2,312	$ 954
2008	$ 2,162	$ 2,324	$ 2,238	$ 1,021
2009	$ 1,942	$ 1,799	$ 2,467	$ 908
2010	$ 1,978	$ 2,058	$ 2,634	$ 712
2011	$ 2,382	$ 2,582	$ 2,575	$ 738
2012	$ 2,563	$ 2,679	$ 2,721	$ 683
2013	$ 2,563	$ 2,733	$ 2,866	$ 682
2014	$ 2,646	$ 2,940	$ 3,148	$ 802
2015	$ 2,438	$ 2,644	$ 3,350	$ 759
Cost per GJ	$ 29.73	$ 32.25	$ 40.85	$ 9.25
2015 NG Savings	$ 1,679	$ 1,886	$ 2,592	elect less fixed
per GJ	$ 20.48	$ 23.00	$ 31.60	$ 18.83



Sources:

Propane & Heating Oil: The Kent Group. Rates taken for London for the South and Thunder Bay for the North

Natural Gas: Union Gas Limited Rate Schedules

Electricity: OEB time-of-use rates & utility-specific charges. Rates taken for London for the South and Thunder Bay for the North

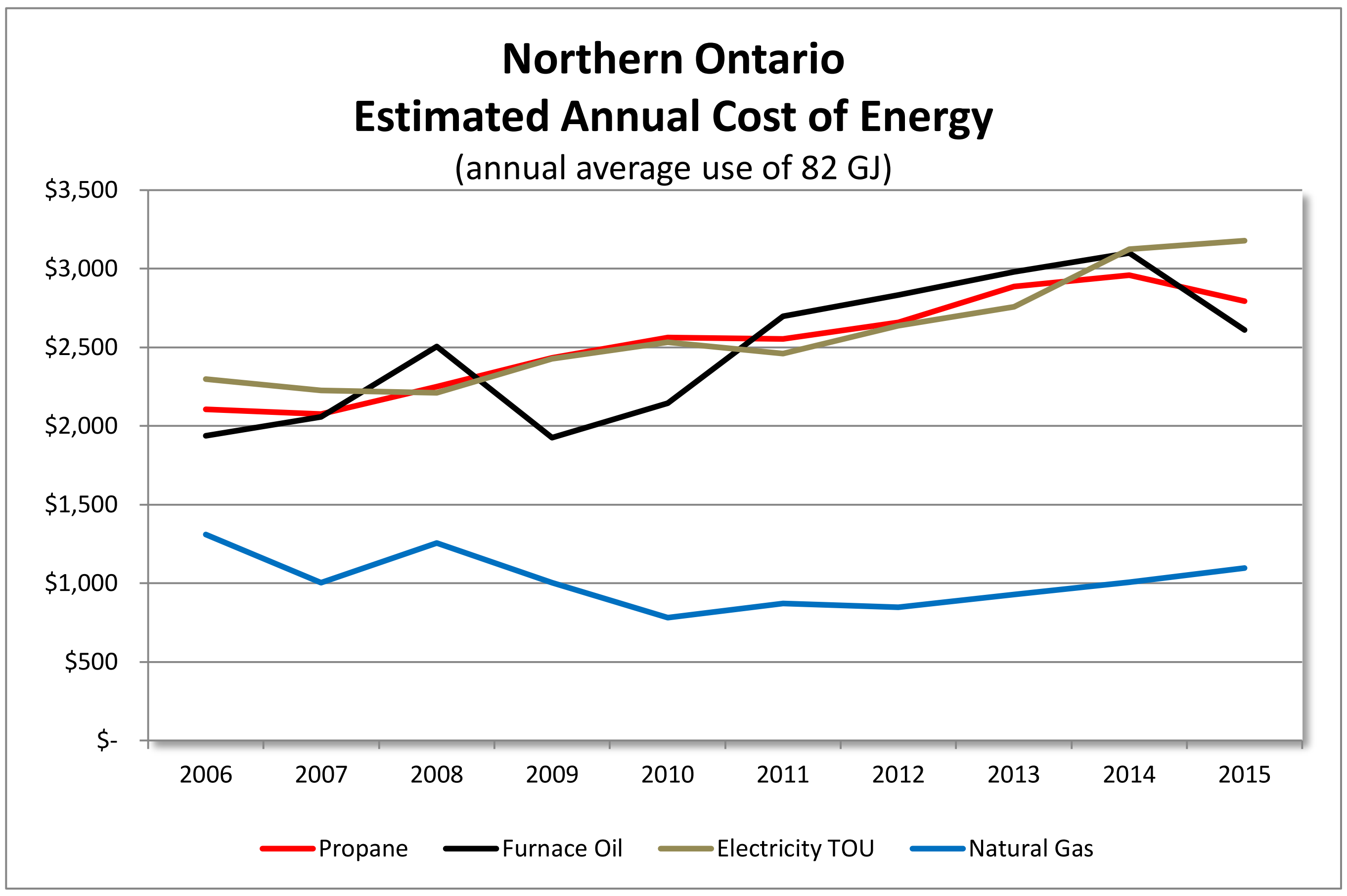
Fixed Monthly Rate: Hydro One medium density monthly fixed charge $ 24.07

Average Annual Savngs

Year	Propane	Furnace Oil	Electricity TOU	Electricity TOU excl remaining Fixed Monthy Charges
2006	$ 620	$ 672	$ 1,162	$ 873
2007	$ 903	$ 1,005	$ 1,357	$ 1,068
2008	$ 1,141	$ 1,303	$ 1,217	$ 928
2009	$ 1,033	$ 891	$ 1,559	$ 1,270
2010	$ 1,266	$ 1,347	$ 1,922	$ 1,634
2011	$ 1,645	$ 1,844	$ 1,837	$ 1,549
2012	$ 1,881	$ 1,996	$ 2,038	$ 1,749
2013	$ 1,881	$ 2,051	$ 2,184	$ 1,895
2014	$ 1,845	$ 2,139	$ 2,346	$ 2,057
2015	$ 1,679	$ 1,886	$ 2,592	$ 2,303

Northern Ontario Estimated Annual Cost of Energy

Year	Propane	Furnace Oil	Electricity TOU	Natural Gas
2006	$ 2,106	$ 1,938	$ 2,300	$ 1,310
2007	$ 2,078	$ 2,059	$ 2,228	$ 1,005
2008	$ 2,250	$ 2,505	$ 2,213	$ 1,258
2009	$ 2,434	$ 1,926	$ 2,427	$ 1,004
2010	$ 2,563	$ 2,146	$ 2,534	$ 782
2011	$ 2,554	$ 2,697	$ 2,462	$ 873
2012	$ 2,659	$ 2,832	$ 2,639	$ 848
2013	$ 2,889	$ 2,981	$ 2,758	$ 929
2014	$ 2,958	$ 3,101	$ 3,124	$ 1,006
2015	$ 2,794	$ 2,610	$ 3,180	$ 1,097
Cost per GJ	$ 34.07	$ 31.83	$ 38.78	$ 13.38
2015 NG Savings	$ 1,696	$ 1,512	$ 2,082	elect less fixed
per GJ	$ 20.69	$ 18.44	$ 25.40	$ 8.49



Sources:

Propane & Heating Oil: The Kent Group. Rates taken for London for the South and Thunder Bay for the North

Natural Gas: Union Gas Limited Rate Schedules

Electricity: OEB time-of-use rates & utility-specific charges. Rates taken for London for the South and Thunder Bay for the North

Fixed Monthly Rate: Hydro One medium density monthly fixed charge $ 24.07

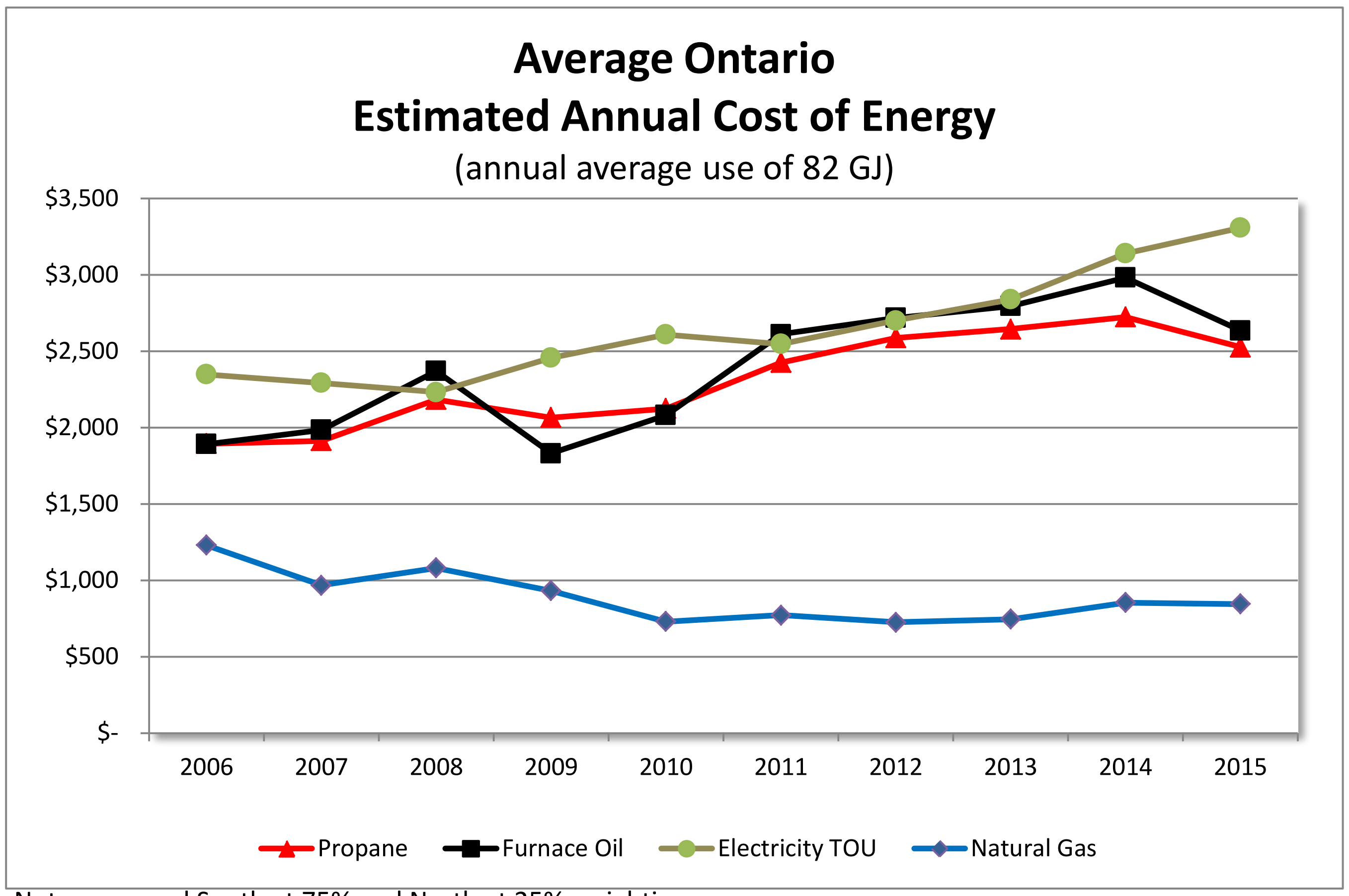
Average Annual Savngs

Year	Propane	Furnace Oil	Electricity TOU	Electricity TOU excl remaining Fixed Monthy Charges
2006	$ 796	$ 628	$ 990	$ 701
2007	$ 1,072	$ 1,054	$ 1,223	$ 934
2008	$ 992	$ 1,247	$ 955	$ 666
2009	$ 1,430	$ 922	$ 1,423	$ 1,134
2010	$ 1,781	$ 1,364	$ 1,752	$ 1,464
2011	$ 1,681	$ 1,824	$ 1,589	$ 1,300
2012	$ 1,810	$ 1,984	$ 1,791	$ 1,502
2013	$ 1,960	$ 2,052	$ 1,829	$ 1,540
2014	$ 1,952	$ 2,095	$ 2,117	$ 1,829
2015	$ 1,696	$ 1,512	$ 2,082	$ 1,794

Average Ontario Estimated Annual Cost of Energy

Year	Propane	Furnace Oil	Electricity TOU	Natural Gas
2006	$ 1,894	$ 1,891	$ 2,348	$ 1,229
2007	$ 1,912	$ 1,984	$ 2,291	$ 967
2008	$ 2,184	$ 2,369	$ 2,231	$ 1,080
2009	$ 2,065	$ 1,831	$ 2,457	$ 932
2010	$ 2,124	$ 2,080	$ 2,609	$ 729
2011	$ 2,425	$ 2,611	$ 2,547	$ 772
2012	$ 2,587	$ 2,717	$ 2,701	$ 724
2013	$ 2,645	$ 2,795	$ 2,839	$ 744
2014	$ 2,724	$ 2,981	$ 3,142	$ 853
2015	$ 2,527	$ 2,636	$ 3,308	$ 843
Cost per GJ	$ 30.81	$ 32.14	$ 40.34	$ 10.28
2015 NG Savings	$ 1,683	$ 1,792	$ 2,464	elect less fixed
per GJ	$ 20.53	$ 21.86	$ 30.05	$ 16.25

EXHIBIT A TAB 1 Figure 1



Note: assumed South at 75% and North at 25% weightings.

Sources:

Propane & Heating Oil: The Kent Group. Rates taken for London for the South and Thunder Bay for the North

Natural Gas: Union Gas Limited Rate Schedules

Electricity: OEB time-of-use rates & utility-specific charges. Rates taken for London for the South and Thunder Bay for the North

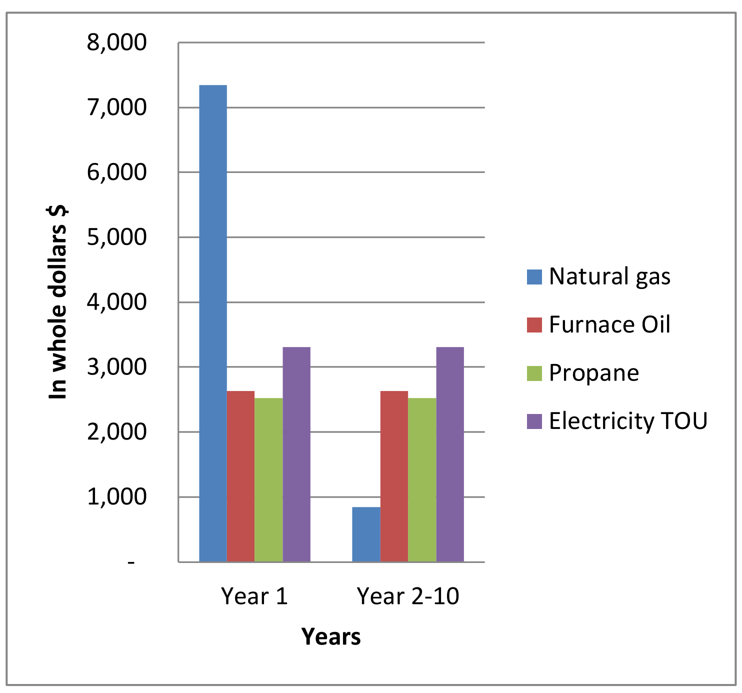
Fixed Monthly Rate: Hydro One medium density monthly fixed charge $ 24.07

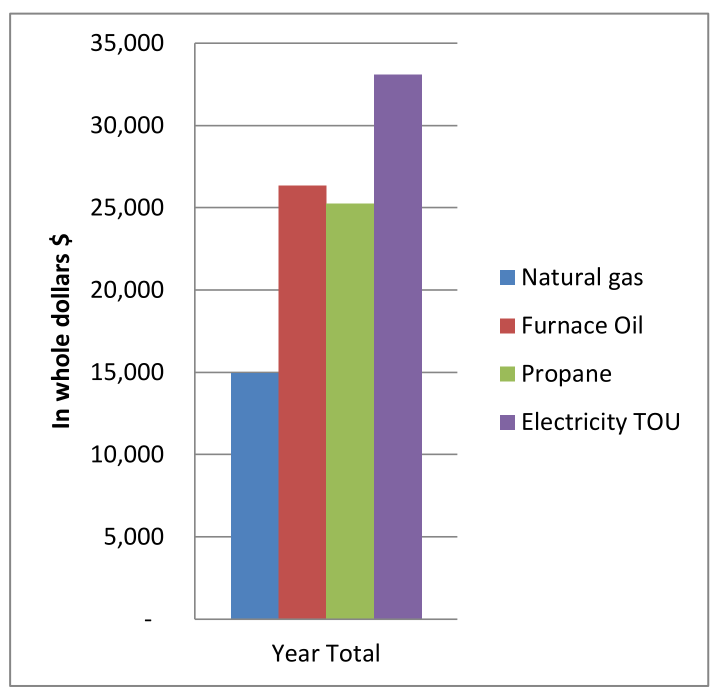
Average Annual Savngs

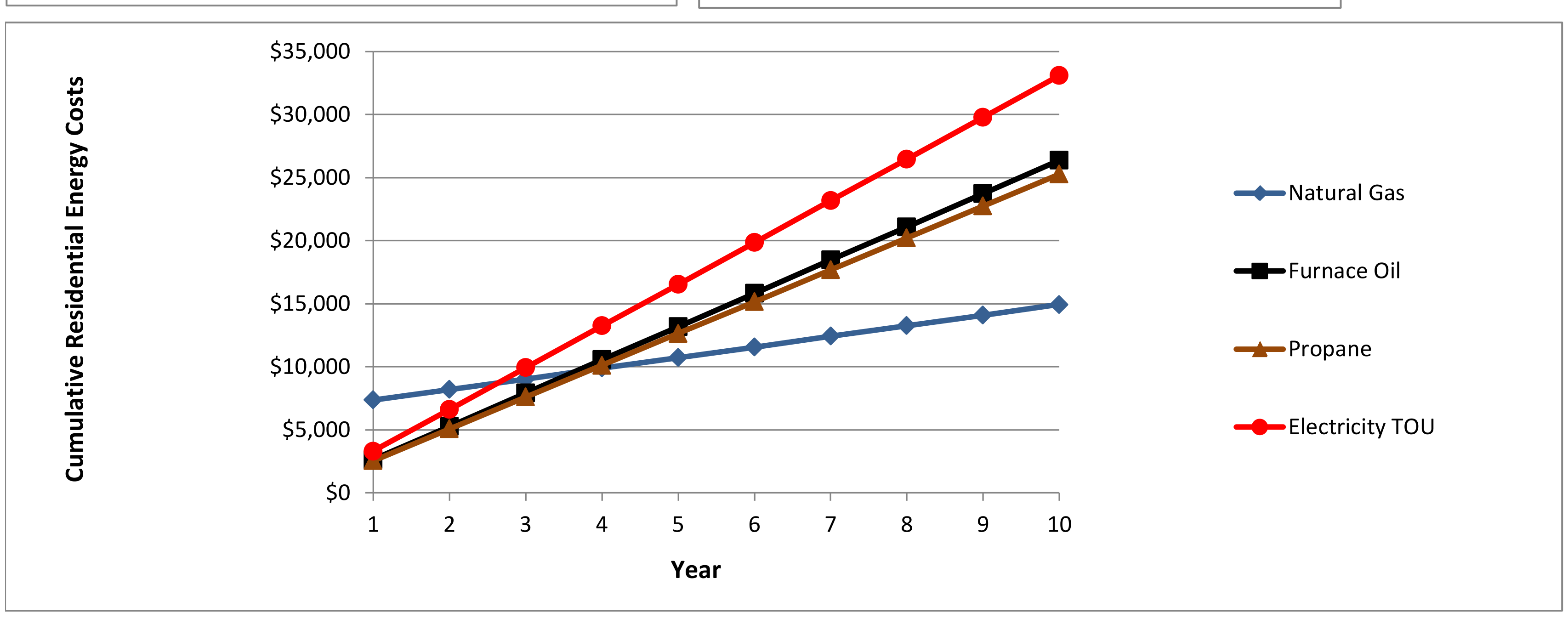
Year	Propane	Furnace Oil	Electricity TOU	Electricity TOU excl remaining Fixed Monthy Charges
2006	$ 664	$ 661	$ 1,119	$ 830
2007	$ 945	$ 1,017	$ 1,324	$ 1,035
2008	$ 1,104	$ 1,289	$ 1,151	$ 862
2009	$ 1,133	$ 899	$ 1,525	$ 1,236
2010	$ 1,395	$ 1,351	$ 1,880	$ 1,591
2011	$ 1,654	$ 1,839	$ 1,775	$ 1,486
2012	$ 1,863	$ 1,993	$ 1,976	$ 1,688
2013	$ 1,901	$ 2,051	$ 2,095	$ 1,806
2014	$ 1,871	$ 2,128	$ 2,289	$ 2,000
2015	$ 1,683	$ 1,792	$ 2,464	$ 2,175
cost/GJ	$ 20.53	$ 21.86	$ 30.05	$ 26.53

Figure 2 Data

	Year 1	Year 2-10	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year Total	
Cost of Natural Gas												
Annual	843	843	843	843	843	843	843	843	843	843		Savings vs Gas
Upfront aid to construct	2,500											
Upfront conversion costs	4,000											
Annual Cost	7,343	843	843	843	843	843	843	843	843	843	14,930	
Cumulative Total	7,343	8,186	9,029	9,872	10,715	11,558	12,401	13,244	14,087	14,930		
Furnace Oil												
Annual cost	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	26,360	11,430
Cumulative Total	2,636	5,272	7,908	10,544	13,180	15,816	18,452	21,088	23,724	26,360		
Propane												
Annual cost	2,527	2,527	2,527	2,527	2,527	2,527	2,527	2,527	2,527	2,527	25,270	10,340
Cumulative Total	2,527	5,054	7,581	10,108	12,635	15,162	17,689	20,216	22,743	25,270		
Electricity TOU												
Annual cost	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	33,080	18,150
Cumulative Total	3,308	6,616	9,924	13,232	16,540	19,848	23,156	26,464	29,772	33,080		







UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, pp. 9-10, Figures 1 and 2

Figures 1 and 2 of Union's Application purport to convey the cost of propane for residential energy purposes over a 10 year period.

a) Confirm whether the source used to develop the propane cost estimates in Figures 1 and 2 relates to auto propane (used for vehicles) or heating propane (used for residential and commercial heating purposes). Provide a copy of the source.

Response:

a) The source used to develop the propane cost estimates in Figure 1 and 2 relates to auto propane. Union is not able to obtain a publically available and reliable source of non-automotive propane end-user prices. Price reporting sources such as The Kent Group and Statistics Canada only provide prices for automotive propane.

   Please see Attachment 1 for the yearly reports for propane prices from the Kent Group. Note that Union uses pricing for London and Thunder Bay areas.

   Any difference between auto propane prices and heating propane prices would not be material enough to cause a change in Union's proposal, given that the current penetration of propane equipment underlying Union's proposal is only 15% as noted in Exhibit A, Tab 1, p. 18, Table 1.

2006 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2006)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	83.9	77.9	77.9	79.4	80.9	80.9	83.9	84.5	81.4	73.3	64.9	72.4	78.4
VANCOUVER	69.9	69.9	69.9	69.9	67.3	66.0	65.3	67.9	66.5	63.5	51.4	62.4	65.8
VICTORIA	63.0	62.4	61.6	62.0	62.8	62.6	62.6	63.6	64.4	62.9	57.6	62.9	62.4
PRINCE GEORGE	67.9	59.9	61.2	61.9	57.9	57.9	66.9	69.9	63.9	54.9	48.9	65.9	61.4
KAMLOOPS	68.4	59.4	59.4	59.4	59.4	59.2	61.4	63.9	62.1	57.4	50.7	62.3	60.2
KELOWNA	68.9	59.9	59.9	59.9	59.9	59.9	66.2	68.7	66.9	55.0	50.7	66.4	61.9
FORT ST. JOHN				61.6	60.6	60.6	60.6	60.6	60.6	60.4	60.2	58.1	60.4
YELLOWKNIFE													
CALGARY	60.7	60.2	59.8	60.6	58.3	57.9	58.1	58.6	57.2	57.4	53.3	52.4	57.9
RED DEER	62.2	60.2	61.2	59.4	57.5	57.9	57.9	61.9	62.9	60.9	62.9	63.8	60.7
EDMONTON	62.2	61.1	60.9	61.2	61.4	63.3	61.6	62.8	63.4	61.8	61.9	62.9	62.0
LETHBRIDGE	65.9	65.4	64.7	65.9	67.4	68.5	65.9	68.0	67.3	68.3	66.9	66.9	66.8
LLOYDMINSTER													
REGINA	78.4	79.4	79.2	80.9	80.5	80.2	78.5	77.9	77.8	78.1	78.9	78.9	79.1
SASKATOON	73.5	73.5	73.5	74.0	73.5	74.1	73.5	73.5	73.5	73.5	73.5	73.5	73.6
PRINCE ALBERT													
WINNIPEG	72.9	72.9	73.8	72.9	72.9	72.9	72.9	72.9	72.9	74.7	72.9	72.9	73.1
BRANDON	76.9	76.9	76.9	76.9	72.1	68.9	68.9	68.9	69.9	69.9	67.9	68.9	71.9
TORONTO	62.2	58.5	56.7	56.0	58.9	58.3	59.1	60.8	60.5	59.0	57.6	57.6	58.8
OTTAWA	54.9	54.9	54.9	54.9	54.9	54.9							54.9
KINGSTON													
PETERBOROUGH				65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9
WINDSOR	59.5	58.4	58.2	57.9	57.5	58.9	60.3	60.4	60.4	63.4	63.4	62.9	60.1
LONDON	58.5	56.4	56.3	56.5	56.9	56.9	56.7	58.7	56.5	56.2	56.1	56.2	56.8
SUDBURY												109.0	109.0
SAULT STE MARIE	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
THUNDER BAY	66.2	67.4	65.5	64.9	64.9	64.9	66.8	65.4	65.4	64.7	64.7	64.7	65.4
NORTH BAY													
TIMMINS													
HAMILTON	63.9	63.9		63.9			63.9	63.9	63.9	63.9	63.9	63.9	63.9
ST. CATHARINES	61.9	61.9	61.9	61.4	63.9	61.9	61.9	60.9	61.2	60.4	61.5	62.8	61.8
MONTRÉAL	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	79.9	79.9	79.9	79.9	73.2
QUÉBEC	71.9	71.9	71.9	71.9	71.9	71.9		71.9	71.4	71.4	71.9	71.9	71.8
SHERBROOKE													
GASPÉ													
CHICOUTIMI	78.3	79.9	79.9	79.9	71.9	71.9	79.9	79.9	79.9	79.9	79.9	79.9	78.4
RIMOUSKI													
TROIS RIVIÉRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	91.6	92.2	91.6	90.2	89.2	89.2	89.2	91.3	94.8	98.5	99.2	100.5	93.1
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI	99.9	99.5	99.0	99.2	99.0	99.0	99.0	99.2	99.0	99.0	99.0	99.0	99.1
CAMPBELLTON													
SUSSEX				92.5	95.0	95.0	95.0	95.0	95.0	95.0	93.8	90.0	94.0
WOODSTOCK													
HALIFAX	105.0	105.0	105.0	103.7	105.0	105.0	105.0	105.0	105.0	105.0	105.0	105.0	104.8
SYDNEY													
YARMOUTH													
TRURO	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	89.9	89.9	89.9	89.9	89.9	99.9	109.9	109.9	109.9	109.9	109.9	109.9	100.7
Canada Ave (V)	65.7	64.5	63.9	63.9	63.2	62.5	62.5	64.0	63.5	62.1	56.3	60.0	62.7
Large Markets Average (S)	69.7	69.9	69.2	69.2	68.9	69.1	69.9	70.5	70.8	70.7	70.1	72.6	70.1
Large Markets Average (P)													
DATE (2006)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: MJ Ervin & Associates Inc. (403) 283-8704

2007 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2007)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	78.1	77.7	79.9	79.9	81.5	81.9	81.9	81.9	83.4	83.9	89.4	95.9	82.9
VANCOUVER	65.9	65.9	67.4	65.8	65.9	65.8	66.2	66.6	67.3	69.0	71.4	76.6	67.8
VICTORIA	62.9	63.2	64.2	64.2	64.2	64.2	64.2	64.2	64.9	65.4	70.3	66.2	64.9
PRINCE GEORGE	65.9	65.9	65.2	61.2	52.9	54.7	65.9	65.9	65.9	59.3	69.9	69.9	63.5
KAMLOOPS	64.0	65.2	64.2	65.5	60.8	60.5	63.6	64.2	64.6	67.6	73.4	77.7	65.9
KELOWNA	65.9	65.9	62.7	59.4	57.7	63.7	65.9	64.8	67.9	70.7	73.4	79.9	66.5
FORT ST. JOHN	58.3	58.6	58.6	58.4	58.8	59.9	60.8	60.0	59.2	58.9	61.3	65.4	59.8
YELLOWKNIFE													
CALGARY	52.4	51.7	52.9	54.3	54.9	54.9	50.5	54.0	56.4	57.0	61.4	60.9	55.1
RED DEER	61.9	67.8	70.9	72.4	72.4	72.4	72.4	76.2	72.4	72.4	74.3	72.4	71.5
EDMONTON	63.5	63.4	63.4	63.4	63.9	63.9	65.4	66.4	66.4	66.4	66.4	66.9	65.0
LETHBRIDGE	66.9	66.9	66.9	66.9	66.1	65.9	65.7	67.9	68.2	68.9	69.6	69.0	67.4
LLOYDMINSTER													
REGINA	76.1	74.2	77.2	75.4	76.4	75.9	76.1	76.9	76.9	76.6	78.3	80.9	76.7
SASKATOON	73.5	73.5	74.7	75.3	75.3	75.3	75.3						74.7
PRINCE ALBERT													
WINNIPEG	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9
BRANDON	69.9	69.9	69.9	69.9	69.9	69.9	72.3	72.9	72.9	72.9	78.7	82.9	72.7
TORONTO	57.2	53.2	53.4	53.4	52.7	56.9	56.9	56.9	56.9	57.4	62.9	65.9	57.0
OTTAWA													
KINGSTON													
PETERBOROUGH	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9
WINDSOR	63.4	62.4	63.4	63.3	56.9	56.9	56.9	56.9	56.9	56.9	58.4	59.9	59.4
LONDON	56.0	56.4	56.3	56.8	56.7	56.7	56.5	56.6	56.0	58.8	60.5	63.3	57.5
SUDBURY	109.2	109.0											
SAULT STE MARIE	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	85.5	80.4
THUNDER BAY	65.0	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7	64.7
NORTH BAY													
TIMMINS													
HAMILTON	63.9	63.9	63.9	63.9	63.9	63.9	63.9	63.9	63.9	63.9	65.9	67.9	64.4
ST. CATHARINES	61.9	61.9	61.9	61.9	63.9	64.4	64.4	64.5	64.4	64.8	65.8	66.0	63.8
MONTRÉAL	79.9	86.9	85.4	85.9	85.9	85.4	85.0	85.0	89.2	89.9	89.9	89.9	86.5
QUÉBEC	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9	71.9
SHERBROOKE													
GASPÉ													
CHICOUTIMI	79.9	79.9	79.9	79.9	79.9	79.9	79.9	76.9	76.9	76.9	76.9	76.9	78.7
RIMOUSKI													
TROIS RIVIÉRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	95.1	96.2	98.7	100.0	100.0	100.3	100.8	101.0	100.8	101.1	101.5	106.9	100.2
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI	99.0	99.0	99.4	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0
CAMPBELLTON													
SUSSEX	94.0	95.0	95.0	96.5	97.0	97.0	97.0	99.0	97.0	97.0	97.0	95.8	96.4
WOODSTOCK		96.9	96.9	102.9	102.9	102.9	102.9	102.7	102.9	102.7			
HALIFAX	105.0	105.0	105.0	105.0	105.0	103.7	100.2	100.5	106.2	105.0	105.0	105.0	104.2
SYDNEY		104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	104.0	
YARMOUTH													
TRURO	109.9	109.9	109.9	109.9	106.6	109.9	109.9	105.9	102.9	109.7	109.9	109.9	108.7
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN		120.0	120.0	120.0	120.0	120.0	119.6	118.2	118.2	119.9	121.3	124.6	
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	109.9	109.9	109.9	109.9	109.9	109.9	109.9	107.5	109.9	109.9	109.9	109.9	109.7
Canada Ave (V)	61.0	60.0	60.9	60.7	60.7	61.8	60.8	61.9	63.0	63.9	67.5	70.1	62.7
Large Markets Average (S)	72.4	71.9	71.0	71.0	70.8	71.0	70.6	70.8	71.3	71.7	73.2	74.3	71.7
Large Markets Average (P)													
DATE (2007)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: MJ Ervin & Associates Inc. (403) 283-8704

2008 **Propane / Propane** **Monthly / mensuelle**

¢/litre **Average retail prices, including taxes / Prix au détail moyenne, avec taxes**

DATE (2008)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	95.5	95.9	95.9	97.9	105.9	105.9	107.1	101.7	97.1	89.4	86.4	84.9	97.0
VANCOUVER	80.1	79.7	79.2	79.9	82.9	79.3	82.1	82.9	77.7	76.6	71.5	65.5	78.1
VICTORIA	67.7	68.6	74.1	76.9	76.9	77.3	80.5	80.9	80.9	80.9	80.3	75.9	76.7
PRINCE GEORGE	69.9	69.9	69.9	69.9	77.9	78.4	79.5	79.9	79.9	79.9	76.4	66.7	74.9
KAMLOOPS	80.1	80.0	78.3	80.2	82.7	79.2	83.7	80.4	78.9	78.4	73.9	65.7	78.5
KELOWNA	83.6	82.4	79.0	80.3	84.2	78.2	84.1	80.4	77.0	78.9	75.8	66.9	79.2
FORT ST. JOHN	68.1	69.7	72.0	75.6	74.9	73.2	76.4	76.3	76.8	73.9	71.7	65.1	72.8
YELLOWKNIFE													
CALGARY	62.3	65.0	68.4	69.9	59.9	60.4	62.1	62.9	62.9	61.4	53.9	47.9	61.4
RED DEER	72.4	72.5	72.4	77.5	86.9	90.0	90.0	89.9	89.9	89.9	89.9	81.9	83.6
EDMONTON	69.7	73.8	75.7	76.0	76.4	76.4	79.9	79.9	79.9	79.9	78.3	67.6	76.1
LETHBRIDGE	68.4	74.0	77.9	77.9	77.9	77.9	79.9	79.9	79.4	81.5	83.4	77.7	78.0
LLOYDMINSTER													
REGINA	83.0	84.3	88.7	91.4	92.2	94.7	97.3	99.1	99.1	97.8	99.9	89.7	93.1
SASKATOON													
PRINCE ALBERT													
WINNIPEG	73.9	77.9	79.5	81.4	86.3	87.9	87.9	87.9	85.4	85.4	85.7	83.1	83.5
BRANDON	83.9	83.9	83.9	87.1	87.9	87.9	87.9	87.9	89.9	89.9	89.9	84.3	87.0
TORONTO	65.9	65.9	65.9	65.9	67.9	70.7	74.7	72.9	69.9	69.9	63.7	59.9	67.8
OTTAWA													
KINGSTON													
PETERBOROUGH													
WINDSOR	59.9	59.9	59.9	59.9	60.7	64.7	69.9	69.9	69.9	66.4	56.2	49.9	62.3
LONDON	64.8	64.4	66.4	66.9	67.9	68.7	70.9	71.9	73.5	70.9	72.5	67.9	68.9
SUDBURY													
SAULT STE MARIE	91.9	91.9	91.9	91.9	93.7	98.9	98.9	98.9	98.7	98.9	97.2	97.5	95.9
THUNDER BAY	64.4	64.3	67.4	70.4	70.9	70.9	70.9	73.4	75.8	77.4	77.4	76.9	71.7
NORTH BAY													
TIMMINS													
HAMILTON	67.9	67.9	67.9	67.9	74.2	77.9	77.9	77.9	77.9	77.9	77.9	68.3	73.5
ST. CATHARINES	67.0	66.9	66.9	66.9	66.9	68.9	73.8	76.2	75.4	75.5	76.2	76.9	71.5
MONTRÉAL	90.9	89.9	93.7	96.1	95.8	95.9	96.7	99.9	101.7	99.9	99.9	101.9	96.9
QUÉBEC	79.9												79.9
SHERBROOKE													
GASPÉ													
CHICOUTIMI	76.9	76.9	78.4	79.2		73.9	73.9	73.9	73.9	73.9	73.9	73.9	75.3
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	97.1	95.0	95.0	99.0	102.0	101.0	98.2	98.3	101.2	100.5	95.8	90.4	97.8
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX		95.8	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	97.0	96.9
WOODSTOCK													
HALIFAX	104.0	100.0	125.0	125.0	128.8	130.0	130.0	130.0	130.0	130.0			123.3
SYDNEY													
YARMOUTH													
TRURO	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9	109.9
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN	124.6												
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	109.9	109.9	109.9	109.9	114.7	127.8	129.1	129.1	129.1	129.1	129.1	129.1	121.4
Canada Ave (V)	71.8	72.5	73.6	74.4	73.6	73.3	76.0	76.1	73.5	72.5	66.9	61.9	72.2
Large Markets Average (S)	74.8	75.0	78.2	79.5	80.5	81.3	82.9	83.6	83.4	82.0	77.5	74.5	79.4
Large Markets Average (P)													
DATE (2008)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: MJ Ervin & Associates Inc. (403) 283-8704

2009 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2009)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	90.7	95.9	89.5	86.7	82.9	82.9	82.9	82.9	83.7	87.9	90.9	94.1	87.6
VANCOUVER	64.0	64.2	61.7	59.7	58.7	52.5	48.8	47.9	53.0	58.1	64.4	65.9	58.2
VICTORIA	65.9	67.8	70.4	69.9	68.9	68.9	69.4	68.0	63.9	63.9	63.9	63.9	67.1
PRINCE GEORGE	57.9	57.9	57.9	57.9	57.9	47.5	46.9	46.9	51.7	60.7	65.9	65.9	56.2
KAMLOOPS	66.7	64.9	59.9	59.9	59.9	53.1	46.9	46.9	54.1	58.9	65.9	67.7	58.7
KELOWNA	67.4	63.7	59.9	59.9	58.7	48.7	46.4	46.4	53.7	59.9	65.9	67.7	58.2
FORT ST. JOHN	64.7	66.9	63.3	60.9	59.2	58.9	59.4	56.8	59.4	59.9	62.9	62.9	61.3
YELLOWKNIFE													
CALGARY	50.2	53.9	52.9	46.4	43.7	42.9	42.9	40.7	39.9	42.9	49.9	53.1	46.6
RED DEER	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
EDMONTON	66.9	66.9	66.9	67.2	65.4	64.1	63.9	63.9	63.9	63.9	63.9	64.5	65.1
LETHBRIDGE	74.8	74.9	74.9	75.6									75.0
LLOYDMINSTER													
REGINA	83.9	87.2	82.9	82.9	82.9	87.1	89.9	89.9	89.9	89.9	89.9	89.9	87.2
SASKATOON													
PRINCE ALBERT													
WINNIPEG	82.4	82.4	82.4	82.4	83.7	80.0	79.4	79.4	79.4	79.4	79.4	79.4	80.8
BRANDON	82.9	82.9	77.9	69.9	69.9	69.7	69.9	69.9	69.9	70.7	72.9	75.7	73.5
TORONTO	59.9	63.8	65.9	65.9	65.9	65.9	65.9	62.7	57.7	56.4	58.4	63.1	62.6
OTTAWA													
KINGSTON													
PETERBOROUGH													
WINDSOR	51.2	55.9	55.3	50.7	49.9	49.9	49.2	46.9	48.9	48.9	51.9	55.7	51.2
LONDON	60.9	59.9	64.9	67.4	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	59.7
SUDBURY													
SAULT STE MARIE	91.9	91.9	91.9	91.9	81.8	81.8	81.8	81.8	81.8	81.8	81.8	81.8	85.2
THUNDER BAY	75.2	72.9	72.9	72.9	72.9	72.9	78.2	79.9	79.9	79.9	79.9	79.9	76.4
NORTH BAY													
TIMMINS													
HAMILTON	67.9	67.9	67.9	67.9	59.9	62.3	63.9	63.9	63.9	63.9	63.9	66.3	65.0
ST. CATHARINES	76.2	75.5	70.9	69.9	69.9	69.9	65.5	64.9	64.9	64.9	64.9	65.9	68.6
MONTRÉAL	105.0	99.9	99.9	97.9	95.9	98.3	99.2	94.9	99.9	99.9	99.9	97.6	99.0
QUÉBEC													
SHERBROOKE													
GASPÉ													
CHICOUTIMI	74.2	74.7	76.3	70.4	59.9	59.9	59.9	59.9	59.9	62.4	79.9	79.9	68.1
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	88.0	88.8	88.8	88.5	89.3	88.0	88.5	88.8	89.4	88.8	89.0	89.0	88.7
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	97.0	97.0	97.0	97.0	94.0	93.0	91.8	93.0	93.0	93.0	93.0	93.0	94.3
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO	109.9	109.9	109.9	109.9	112.8	113.6	109.8	109.0	109.0	109.0	109.0	109.0	110.1
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	129.1	129.1	129.1	129.1	129.1	128.1	129.1	129.1	129.1	129.1	129.1	129.1	129.0
Canada Ave (V)	61.4	64.5	63.3	61.5	60.1	58.9	57.8	54.2	55.6	57.5	61.1	63.2	59.9
Large Markets Average (S)	71.4	72.6	71.8	70.2	68.1	68.1	68.1	67.1	67.6	68.7	70.8	71.2	69.6
Large Markets Average (P)													
DATE (2009)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: MJ Ervin & Associates Inc. (403) 283-8704

2010 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2010)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	94.9	104.0	98.1	91.9	92.4	91.1	89.9	90.5	92.9	95.9	96.7	96.9	94.6
VANCOUVER	71.0	75.2	72.5	68.2	68.2	67.5	63.2	71.9	73.9	76.9	80.7	77.9	72.2
VICTORIA	65.8	70.2	70.7	68.9	68.9	68.9	68.9	68.9	68.9	68.9	73.1	75.9	69.8
PRINCE GEORGE	69.7	67.2	65.9	65.9	65.9	65.9	65.9	65.7	65.9	65.9	65.9	65.9	66.3
KAMLOOPS	72.7	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.8
KELOWNA	72.7	73.9	73.9	73.9	73.9	73.9	76.3	73.9	73.9	73.9	73.9	73.9	74.0
FORT ST. JOHN	68.7	68.9	66.5	66.2	64.9	64.9	63.4	62.9	62.9	62.9	60.1	69.9	65.2
YELLOWKNIFE													
CALGARY	62.2	62.9	62.9	62.9	55.9	55.9	55.9	54.9	50.9	50.9	50.9	50.9	56.4
RED DEER	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
EDMONTON	67.4	68.9	73.7	74.9	66.9	66.9	66.9	66.9	66.9	66.9	66.9	66.9	68.3
LETHBRIDGE													
LLOYDMINSTER													
REGINA	89.9	89.9	91.9	88.9	88.9	88.4	86.7	88.1	90.4	94.9	94.9	94.9	90.6
SASKATOON													
PRINCE ALBERT													
WINNIPEG	79.4	82.9	82.9	82.9	81.4	79.9	79.9	79.9	79.9	79.9	79.9	79.9	80.7
BRANDON	85.9	90.4	89.3	74.9	74.9	70.9	64.9	64.9	64.9	69.9	69.9	69.9	74.2
TORONTO	68.4	69.9	69.9	59.9	59.9	59.9	59.9	59.9	58.9	58.7	60.6	62.4	62.4
OTTAWA													
KINGSTON													
PETERBOROUGH													
WINDSOR	62.9	65.9	61.5	59.9	59.9	59.3	59.9	59.9	59.9	59.9	59.9	59.9	60.7
LONDON	60.4	63.9	63.9	63.9	63.9	62.1	55.1	56.6	59.9	62.4	59.9	59.9	61.0
SUDBURY													
SAULT STE MARIE	84.3	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.3
THUNDER BAY	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
NORTH BAY													
TIMMINS													
HAMILTON	69.9	69.9	69.9	69.9	69.9	70.0	70.0	70.0	70.0	70.0	70.0	63.9	69.4
ST. CATHARINES	67.4	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.7
MONTRÉAL	98.7	99.4	100.7	99.9	94.9	98.1	95.0	96.4	95.8	95.9	99.1	99.9	97.8
QUÉBEC													
SHERBROOKE													
GASPÉ													
CHICOUTIMI	79.9	79.9	79.9	79.9	79.9	79.5	79.9	78.5	79.9	79.9	79.9	79.9	79.8
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	92.3	96.8	96.0	90.0	89.3	92.4	87.0	90.0	89.3	90.8	90.8	92.0	91.4
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO	109.0	109.0	109.0	109.0	120.4	114.7	118.3	113.6	114.7	114.7	114.7	114.7	113.5
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	129.1	129.1	129.1	127.8	127.8	129.1	129.1	129.0	129.1	129.1	129.1	129.1	128.9
Canada Ave (V)	70.6	72.4	71.3	65.4	64.3	64.2	62.8	65.9	64.8	66.3	68.2	67.4	67.0
Large Markets Average (S)	74.7	76.4	76.4	74.4	73.3	73.1	71.9	72.9	73.0	73.9	74.6	74.1	74.1
Large Markets Average (P)													
DATE (2010)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: Kent Marketing Services Limited. (519) 672-7000

2011 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2011)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	103.2	102.9	102.9	102.9	102.9	102.9	103.9	103.5	104.9	108.9	108.9	108.9	104.7
VANCOUVER	80.4	75.9	77.5	74.9	74.9	74.9	73.1	68.9	69.9	74.4	78.9	78.9	75.2
VICTORIA	75.9	75.9	75.9	75.9	75.9	75.9	76.9	76.9	76.9	76.9	76.9	79.9	76.7
PRINCE GEORGE	65.9	65.9	70.7	71.9	71.9	71.9	72.4	72.1	71.9	71.9	71.9	71.9	70.9
KAMLOOPS	78.4	79.9	83.5	79.9	79.9	79.9	80.9	80.9	80.9	80.9	80.9	80.9	80.6
KELOWNA	77.7	79.0	80.4	80.7	79.9	79.9	78.7	79.9	79.9	79.9	79.9	79.9	79.6
FORT ST. JOHN	68.8	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	75.3	72.9	70.5
YELLOWKNIFE													
CALGARY	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
RED DEER	79.9	79.9	79.9	79.9	79.9	78.4	73.9	73.9	73.9	73.9	73.9	73.9	76.8
EDMONTON	66.9	66.9	66.9	66.9	70.5	75.9	74.9	75.9	75.9	75.9	75.9	75.9	72.4
LETHBRIDGE													
LLOYDMINSTER													
REGINA	94.9	94.9	90.1	91.9	104.9	104.9	105.9	105.9	105.9	106.9	106.9	106.9	101.7
SASKATOON													
PRINCE ALBERT													
WINNIPEG	79.9	79.9	79.9	79.9	79.9	83.4	86.2	85.9	85.9	85.9	85.9	85.9	83.2
BRANDON	76.9	76.9	76.9	76.9	76.9	76.9	83.4	89.9	89.9	89.9	89.9	89.9	82.9
TORONTO	63.5	62.4	62.0	61.9	62.2	61.4	61.4	63.7	64.0	65.9	65.9	65.8	63.3
OTTAWA													
KINGSTON													
PETERBOROUGH													
WINDSOR	66.9	67.9	67.9	67.9	67.9	68.4	69.9	69.9	69.9	72.2	72.9	72.9	69.5
LONDON	69.9	69.9	69.9	69.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	76.6
SUDBURY													
SAULT STE MARIE	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	91.9	96.7	99.9	93.0
THUNDER BAY	79.9	79.9	79.9	76.4	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.6
NORTH BAY													
TIMMINS													
HAMILTON	68.0	69.0	69.0	69.0	67.9	68.4	69.9	69.9	69.9	71.4	72.9	72.9	69.8
ST. CATHARINES	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9
MONTRÉAL	100.3	100.2	102.0	95.4	95.4	95.3	95.4	95.4	95.4	95.4	95.4	95.4	96.7
QUÉBEC													
SHERBROOKE													
GASPÉ													
CHICOUTIMI	79.9	79.9	79.9	79.9	79.8	79.8	79.9	79.9	79.9	79.9	79.9	79.9	79.9
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	92.0	92.0	92.0	92.0	89.4	79.0	79.0	79.0	79.0	83.0	83.0	83.0	85.2
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO	114.7												114.7
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK	129.1	129.1	126.1	129.1	129.1	125.5							128.0
Canada Ave (V)	73.5	70.8	71.9	70.6	71.0	70.5	69.7	70.1	70.4	73.3	74.0	73.5	71.6
Large Markets Average (S)	77.8	77.6	77.5	77.1	78.6	78.5	78.7	78.8	78.9	80.1	80.3	80.1	78.7
Large Markets Average (P)													
DATE (2010)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: Kent Marketing Services Limited. (519) 672-7000

2012 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2012)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	105.3	96.8	98.9	95.3	91.3	86.9	86.9	83.9	83.9	85.5	86.9	86.9	90.7
VANCOUVER	78.9	78.9	78.9	78.7	78.9	78.9	78.9	77.7	78.9	78.9	78.9	78.9	78.8
VICTORIA	79.9	79.9	79.9	79.9	79.9	79.9	78.3	77.9	77.9	77.9	77.4	77.9	78.9
PRINCE GEORGE	71.9	71.9	71.9	71.9	71.9	70.4	69.9	69.9	69.9	69.9	69.9	69.9	70.8
KAMLOOPS	80.9	80.9	80.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	80.2
KELOWNA	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
FORT ST. JOHN	74.1	75.9	71.4	69.9	69.9	69.9	69.9	69.9					71.4
YELLOWKNIFE													
CALGARY	79.9	79.9	79.9	79.9	79.9	77.7	71.2	71.2	70.2	71.5	72.2	72.6	75.5
RED DEER	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9
EDMONTON	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.7	75.9	75.9
LETHBRIDGE					79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
LLOYDMINSTER													
REGINA	106.9	104.4	101.9	101.9	100.1	98.9	98.9	98.4	96.9	96.9	96.9	96.9	99.9
SASKATOON													
PRINCE ALBERT						110.0	110.0	110.0	109.0	106.0	105.9	105.9	108.1
WINNIPEG	85.9	85.9	85.9	85.9	85.9	82.9	81.1	79.9	79.9	79.9	79.9	79.9	82.8
BRANDON	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9
TORONTO	65.8	65.9	65.9	63.2	62.9	62.9	62.9	62.9	62.9	62.9	62.2	62.2	63.5
OTTAWA													
KINGSTON													
PETERBOROUGH					79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
WINDSOR	72.9	70.4	62.9	62.9	60.5	56.9	56.9	56.9	56.9	56.9	56.9	56.9	60.7
LONDON	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
SUDBURY													
SAULT STE MARIE	99.9	99.9	98.2	91.2	92.9	91.2	94.3	92.9	92.9	91.5	92.9	92.9	94.2
THUNDER BAY	79.9	81.2	80.5	80.5	88.9	94.9	94.9	90.5	89.3	82.4	83.0	83.7	85.8
NORTH BAY													
TIMMINS													
HAMILTON	72.9	67.9	62.9	62.9	60.5	59.9	59.9	59.9	56.9	56.9	56.9	56.9	61.2
ST. CATHARINES	71.7	72.9	72.9	69.9	69.9	69.9	71.7	72.9	72.9				71.6
MONTRÉAL	101.1	109.9	109.9	109.9	101.9	97.4	89.9	109.9	110.0	94.9	94.9	94.9	102.1
QUÉBEC													
SHERBROOKE													
GASPÉ													
CHICOUTIMI	79.9	79.9	79.9	79.9	78.3	77.9	77.9	77.9	79.4	79.9	79.9	79.9	79.2
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	83.0	83.0	81.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	81.0	83.5	80.4
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	93.0	93.0	93.0	93.0	93.0	93.0	90.0	90.0	90.0	90.0	90.0	90.0	91.5
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO													
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK													
Canada Ave (V)	74.3	74.6	74.6	73.1	72.8	72.2	70.9	71.2	71.4	71.1	70.8	70.9	72.3
Large Markets Average (S)	81.0	81.1	79.9	79.4	78.8	78.2	77.2	78.1	77.8	76.7	76.8	77.1	78.5
Large Markets Average (P)													
DATE (2012)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: Kent Marketing Services Limited. (519) 672-7000

Filed: 2015-12-09
EB-2015-0179
Exhibit B.CPA.2
Attachment 1
8 of 10

2013 ¢/litre	Propane / Propane Average retail prices, including taxes / Prix au détail moyenne, avec taxes									Monthly / mensuelle			
DATE (2013)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	87.9	91.9	92.9	92.9	92.9	92.9	92.9	93.2	96.9	100.5	102.9	106.7	95.4
VANCOUVER	78.9	78.9	78.9	78.9	79.7	80.6	80.5	80.7	80.9	80.9	80.8	84.1	80.3
VICTORIA	77.9	77.9	79.9	79.9	80.3	81.4	81.4	81.4	83.3	84.4	88.9	91.9	82.4
PRINCE GEORGE	69.9	69.9	69.9	71.1	71.9	71.9	71.9	71.9	71.9	71.9	72.9	77.1	71.9
KAMLOOPS	79.9	79.9	79.9	79.9	77.9	77.9	77.9	77.9	77.9	77.9	80.4	87.9	79.6
KELOWNA	79.9	79.9	79.9	79.9	79.9	79.9	76.9	74.9	74.9	74.9	78.8	85.9	78.8
FORT ST. JOHN					69.9	69.9	69.9	69.9	69.9	69.9	69.9	69.9	
YELLOWKNIFE													
CALGARY	73.1	75.2	75.2	77.2	76.9	75.9	75.9	76.7	79.7	80.8	85.4	89.2	78.5
RED DEER	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	73.9	82.9	74.7
EDMONTON	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9	75.9
LETHBRIDGE	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
LLOYDMINSTER													
REGINA	97.7	97.9	102.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	110.4	113.5	105.3
SASKATOON													
PRINCE ALBERT	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9	105.9
WINNIPEG	79.9	82.4	84.9	84.9	84.9	84.9	84.9	84.9	84.9	84.9	84.9	86.9	84.4
BRANDON	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9
TORONTO	61.9	61.9	61.9	61.9	61.9	60.2	57.9	57.4	56.9	58.4	60.7	65.6	60.5
OTTAWA													
KINGSTON													
PETERBOROUGH	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
WINDSOR	56.9	56.9	56.9	59.3	59.9	59.9	59.7	59.9	62.4	64.9	66.2	71.9	61.2
LONDON	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9
SUDBURY													
SAULT STE MARIE	92.9	91.2	92.9	92.9	89.4	92.9	92.9	92.9	92.9	92.9	94.2	97.9	93.0
THUNDER BAY	84.9	87.4	91.8	91.4	88.7	88.7	90.8	92.9	92.9	93.6	93.7	92.9	90.8
NORTH BAY													
TIMMINS													
HAMILTON	56.9	56.9	56.9	59.3	59.9	59.9	59.9	59.9	59.9	59.9	63.7	70.9	60.3
ST. CATHARINES				70.9	70.9	69.4	65.7	63.4	68.9	69.9	69.9	76.4	69.5
MONTRÉAL	94.9	94.9	94.9	94.9	93.7	92.4	92.4	92.4	92.4	92.4	92.4	92.4	93.3
QUÉBEC				98.4	98.4	98.4	98.4	98.4	98.4	98.4	98.4	98.4	98.4
SHERBROOKE													
GASPÉ													
CHICOUTIMI	82.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	80.2
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	84.0	84.0	82.8	79.0	79.0	79.0	79.7	79.9	79.9	79.9	79.9	79.9	80.6
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	90.0	90.0	93.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	93.3
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO													
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK													
Canada Ave (V)	70.9	71.3	71.4	71.7	71.8	71.1	70.0	69.9	70.2	71.1	72.9	76.9	71.6
Large Markets Average (S)	77.6	77.9	78.8	79.9	79.7	79.5	79.3	79.3	80.1	80.6	81.9	84.4	79.9
Large Markets Average (P)													
DATE (2013)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: Kent Marketing Services Limited. (519) 672-7000

2014 **¢/litre**

Propane / Propane
Average retail prices, including taxes / Prix au détail moyenne, avec taxes

Monthly / mensuelle

DATE (2014)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave
WHITEHORSE	113.9	128.9	117.7	108.9	102.9	102.9	98.3	94.9	97.9	97.9	97.9	92.3	104.5
VANCOUVER	89.4	108.0	101.4	89.8	90.2	88.2	88.6	89.9	88.2	88.2	84.1	82.7	90.7
VICTORIA	98.0	119.2	111.0	101.5	98.2	97.9	92.7	91.9	91.9	91.9	91.9	90.7	98.1
PRINCE GEORGE	87.4	115.9	108.9	105.3	97.4	84.9	84.9	84.9	84.9	84.9	89.9	86.3	93.0
KAMLOOPS	96.4	115.9	102.2	93.9	89.9	84.9	85.1	84.9	84.9	84.9	83.7	81.4	90.7
KELOWNA	92.9	112.9	102.0	91.9	89.9	84.9	84.9	84.9	84.9	84.9	80.5	79.7	89.5
FORT ST. JOHN													
YELLOWKNIFE													
CALGARY	98.2	118.9	105.7	94.6	88.6	88.7	92.2	89.9	87.4	88.9	88.9	87.8	94.2
RED DEER	102.7	125.9	111.5	105.0	105.0	100.0	88.0	85.0	85.0	85.9	85.9	85.9	97.1
EDMONTON	81.9	99.7	108.4	99.9	99.9	99.9	98.7	97.9	91.5	89.7	89.9	89.7	95.6
LETHBRIDGE	79.9	119.9	119.9	99.9	99.9	99.9	93.9	89.9	89.9	99.9	99.9	95.9	99.1
LLOYDMINSTER													
REGINA	119.9	129.7	131.9	122.9	116.9	114.9	114.9	111.2	99.9	99.9	100.9	103.9	113.9
SASKATOON													
PRINCE ALBERT	110.9	126.2	121.4	115.1	111.9	111.9	111.9	110.9	110.9	110.9	110.9	110.9	113.6
WINNIPEG	109.2	162.4	128.9	98.4	89.9	100.6	89.9	87.3	89.9	89.9	89.9	89.9	102.2
BRANDON	89.9	131.2	124.9	124.9	124.9	124.9	124.9	124.9	124.9	124.9	124.9	124.9	122.5
TORONTO	74.9	100.7	92.6	73.5	63.9	61.3	57.8	57.4	57.4	57.4	57.2	56.9	67.6
OTTAWA													
KINGSTON													
PETERBOROUGH	79.9	120.9	120.9	120.9	120.9	120.9	104.2	119.0	119.5	119.9	119.9	119.9	115.6
WINDSOR	84.2	106.7	82.7	71.9	63.4	59.9	59.9	59.9	60.3	61.9	59.4	56.1	68.8
LONDON	81.2	84.9	84.9	99.9	79.9	81.4	80.7	79.9	79.9	69.9	72.9	81.9	81.4
SUDBURY													
SAULT STE MARIE	107.8	124.4	137.3	120.9	118.9	118.9	118.9	117.9	114.9	114.9	114.9	102.9	117.7
THUNDER BAY	92.8	92.4	93.0	92.9	91.8	92.4	92.4	91.8	90.9	90.9	90.9	91.7	92.0
NORTH BAY													
TIMMINS													
HAMILTON	84.9	106.7	87.4	74.7	68.7	61.9	67.9	65.9	59.9	59.9	60.4	61.9	71.7
ST. CATHARINES	94.5	112.2	95.8	75.8	66.6	60.6	60.0	60.0	60.0	60.0	60.0	60.0	72.1
MONTRÉAL	92.4	92.4	92.4	92.4	94.3	94.9	94.9	96.6	98.1	94.9	94.9	94.9	94.4
QUÉBEC	97.8	95.9	95.9	95.9	101.9	103.9	103.9	101.4	93.9	93.9	93.9	93.9	97.7
SHERBROOKE													
GASPÉ													
CHICOUTIMI	79.9	79.9	82.7	85.4	85.4	86.8	84.3	85.4	85.4	86.8	90.9	90.9	85.3
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINTJOHN	83.9	98.3	93.5	88.0	88.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	83.7
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	99.3	121.5	118.5	116.2	109.5	99.5	101.0	101.0	101.0	101.0	101.0	101.0	105.9
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO													
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
STJOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK													
Canada Ave (V)	84.9	105.6	97.5	82.0	75.8	73.7	72.1	72.0	71.2	71.3	70.1	69.5	78.8
Large Markets Average (S)	91.4	106.7	99.3	91.1	86.7	85.8	84.9	84.1	82.1	81.4	81.6	82.0	88.1
Large Markets Average (P)													
DATE (2014)	Jan/jan	Feb/fev	Mar/mar	Apr/avr	May/mai	Jun/jui	Jul/jui	Aug/aou	Sep/sep	Oct/oct	Nov/nov	Dec/dec	Ave

S-Simple V-Volume Weighted P-Population Weighted

Prepared by: Kent Marketing Services Limited. (519) 672-7000

2015 c/litre	Propane / Propane Retail prices, including taxes, self serve / Prix au detail, avec taxes, libre service												
DATE(2015)	**Jan/jan**	**Feb/fev**	**Mar/mar**	**Apr/avr**	**May/mai**	**Jun/jui**	**Jul/jui**	**Aug/aou**	**Sep/sep**	**Oct/oct**	**Nov/nov**	**Dec/dec**	**Average**
WHITEHORSE	83.9	83.9	83.9	83.9	83.9	83.1	81.9	81.9	81.9	81.9			83.0
VANCOUVER	81.2	77.9	76.0	75.4	74.9	75.0	75.0	74.0	74.3	73.6			75.7
VICTORIA	88.9	87.9	87.9	86.8	85.6	87.2	87.9	89.1	88.9	88.9			87.9
PRINCE GEORGE	77.2	75.9	75.9	68.4	65.9	65.9	65.9	65.9	75.9	75.9			71.3
KAMLOOPS	77.6	73.9	73.9	73.9	73.9	73.9	73.9	73.9	74.5	73.9			74.3
KELOWNA	76.2	74.6	73.9	73.9	73.9	74.5	73.9	73.9	74.3	73.9			74.3
FORT ST. JOHN													
ABBOTSFORD						69.9	69.9	69.9	69.9	69.9			69.9
YELLOWKNIFE													
CALGARY	84.0	83.6	81.9	83.6	81.2	80.2	79.6	70.6	68.8	68.2			78.2
RED DEER	87.4	86.6	80.4	81.0	80.9	81.3	83.4	83.4	80.6	77.9			82.3
EDMONTON	89.9	88.5	82.9	81.6	76.8	76.6	79.4	78.5	77.6	76.4			80.8
LETHBRIDGE	89.9	89.9	89.9	89.9	89.9	81.9	79.9	79.9	83.9	89.9			86.5
LLOYDMINSTER													
REGINA	103.9	103.9	103.9	103.9	101.4	98.9	98.9	98.9	95.7	90.9			100.0
SASKATOON	89.9	87.4	87.9	88.4	84.9	87.9	87.9	87.9	86.1	85.8			87.4
PRINCE ALBERT	110.9	110.9	119.9	119.9	119.9	118.7	116.9	113.9	114.5	119.9			116.5
WINNIPEG	89.9	88.6	82.9	83.4	82.9	82.4	80.4	80.4	79.6	78.0			82.9
BRANDON	124.9	124.9	124.9	124.9	124.9	123.7	121.9	121.9	121.9	121.9			123.6
TORONTO	55.9	52.9	51.0	46.8	45.9	45.0	44.9	44.9	35.7	35.4			45.8
OTTAWA													
KINGSTON													
PETERBOROUGH	99.9	80.0	83.8	99.0	99.0	99.0	99.9	99.9	99.9	99.9			96.0
WINDSOR	51.2	49.9	49.9	46.9	45.4	40.7	39.9	39.9	43.3	46.9			45.4
LONDON	84.2	83.2	71.9	76.2	74.9	74.9	74.9	74.9	70.9	64.9			75.1
SUDBURY													
SAULT STE MARIE	94.9	94.9	94.9	94.9	94.9	94.9	94.9	94.9	94.9	94.9			94.9
THUNDER BAY	87.9	86.9	86.9	86.9	86.9	86.9	86.9	86.9	86.8	86.9			87.0
NORTH BAY													
TIMMINS													
HAMILTON	58.4	54.9	49.9	49.9	54.9	54.9	54.9	54.9	45.9	39.9			51.8
ST. CATHARINES	57.8	55.5	55.5	55.5	52.2	48.9	46.1	46.2	49.1	53.5			52.0
MONTRÉAL	94.9	83.6	79.9	79.9	79.9	79.9	79.9	79.1	80.6	87.0			82.5
QUÉBEC	93.9	93.4	91.2	91.7	91.9	91.9	91.9	86.9	71.9	71.9			87.7
SHERBROOKE													
GASPÉ													
CHICOUTIMI	90.9	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0			91.0
RIMOUSKI													
TROIS RIVIÈRES													
DRUMMONDVILLE													
VAL D'OR													
SAINT JOHN	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0			79.0
FREDERICTON													
MONCTON													
BATHURST													
EDMUNDSTON													
MIRAMICHI													
CAMPBELLTON													
SUSSEX	99.5	99.0	99.0	99.0	99.0	93.0	89.0	83.8	78.0	78.0			91.7
WOODSTOCK													
HALIFAX													
SYDNEY													
YARMOUTH													
TRURO													
KENTVILLE													
NEW GLASGOW													
CHARLOTTETOWN													
ST JOHNS													
GANDER													
LABRADOR CITY													
CORNER BROOK													
Canada Ave(V)	68.1	65.0	63.1	60.8	59.9	59.3	59.1	57.8	52.5	52.3			59.8
Large Markets Ave(S)	81.3	79.3	77.0	76.9	75.9	75.4	76.1	75.3	73.5	73.1			76.4
DATE(2015)	**Jan/jan**	**Feb/fev**	**Mar/mar**	**Apr/avr**	**May/mai**	**Jun/jui**	**Jul/jui**	**Aug/aou**	**Sep/sep**	**Oct/oct**	**Nov/nov**	**Dec/dec**	**Average**

S-Simple V-Volume Weighted P-Population Weighted

Prepared by Kent Marketing Services Limited. Tel: (519) 672-7000

To print, copy contents to, and print from a spreadsheet

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Union includes tables, figures and appendices throughout the Application which use a minimum TES period of 4 years. The TES period proposed by Union for the majority of proposed projects described in Appendix D is 10 years. The tables, figures and appendices which reflect the 4-year TES periods do not allow for proper analysis of projects with a 10-year TES period, nor do they allow for consideration of what the financial impacts would be if all projects had a minimum TES period of 10 years.

a) Revise all tables, figures, and appendices using a minimum TES period of 10 years.

Response:

Union's proposal sets a minimum PI of 0.4 for the project economics and varies the term for recovery of the proposed TES. Setting a minimum term of 10 years for recovery of the proposed TES increases the P.I. for projects with a term of less than 10 years under Union's proposal. Attachment 1 provides a revision to a portion of Exhibit A, Tab 1, Appendix D wherein the Projects that meet a P.I. of 0.4 with varying TES/ITE terms (four years to 10 years) has been revised to show the P.I. if the TES/ITE term was fixed at 10 years in all cases.

Opportunity Assessment Summary

Row	Community Name	Natural PI*	TES/ITE Months as Proposed	PI Including Proposed TES/ITE	TES/ITE Months 10 Years	PI Including 10 Years TES/ITE
1	Milverton	0.32	48	0.57	120	1.00
2	Prince Township, Sault Ste Marie	0.38	48	0.50	120	0.72
3	Lambton Shores, Kettle Point First Nation	0.42	48	0.73	120	1.03
4	~~Walpole Island First Nation- main commercial area~~					
5	Moraviantown First Nation- main commercial area	0.35	48	0.58	120	0.89
6	Lagoon City (Orillia)	0.42	48	0.54	120	0.78
7	Hidden Valley/Huntsville	0.38	48	0.52	120	0.76
8	Santa's Village/Beaumont Dr, Bracebridge	0.36	48	0.49	120	0.72
9	Canal, Gravenhurst	0.33	48	0.44	120	0.65
10	Northshore Rd / Peninsula Rd North Bay	0.33	48	0.43	120	0.63
11	Hornby	0.17	72	0.40	120	0.55
12	Oneida First Nation	0.28	48	0.42	120	0.70
13	Auburn	0.27	48	0.44	120	0.72
14	Cedar Springs	0.25	48	0.40	120	0.67
15	Astorville	0.29	49	0.40	120	0.57
16	~~***Brenman Line, Servern Twp (Gravenhurst)~~					
17	Nipissing First Nation / Jocko Point	0.28	60	0.40	120	0.55
18	~~***Munsee Delaware First Nation~~					
19	Chippewa of the Thames First Nation- phase 3 & 4	0.21	64	0.40	120	0.57
20	Sheffield	0.20	70	0.40	120	0.56
21	Turkey Point	0.20	83	0.40	120	0.51
22	Rockton	0.19	79	0.40	120	0.52
23	Chippewas of the Saugeen	0.19	83	0.40	120	0.51
24	Washago	0.23	88	0.40	120	0.46
25	E Floral (T Bay area)	0.21	84	0.40	120	0.47
26	Haldimand Shores	0.20	105	0.40	120	0.42
27	Latchford, Tri Town	0.20	111	0.40	120	0.41
28	Belwood	0.18	95	0.40	120	0.46
29	Kincardine. Tiverton, Paisley, Chesley	0.23	84	0.40	120	0.49
30	~~***Little Longlac~~					
31	Swiss Meadow	0.15	111	0.40	120	0.42
32	Boblo Island	0.15	117	0.40	120	0.40
33	Village of Warwick	0.14	120	0.40	120	0.40

* Project profitabilty index-based on customer forecast and distribution revenue, excluding TES and ITE contributions.

*** Project does not meet definition of Community Expansion Project so would not be eligible for reduced PI without additional project scope.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 1, lines 8-11
Union Gas' energy conservation web page:
https://www.uniongas.com/environment/energy-conservation

Union acknowledges at page 1 of the Application that the Ontario government intends to "implement a cap and trade program whose objective is to significantly reduce the use of natural gas". Union also acknowledges on its web site that energy conservation is "the right thing to do". However, there is no indication in any of the forecasts, estimates, and predictions that comprise Union's Application that Union has accounted for reductions in natural gas usage in determining the viability or profitability of the proposed projects.

a) Given the Ontario government's commitment to energy conservation and significantly reducing the use of natural gas, and Union's statement that "energy conservation is the right thing to do", how will the expected drop in natural gas usage as a result of these and other initiatives impact the financial case and attachment forecasts presented in this Application? Please include all underlying data, calculations, assumptions, and source documents.

Response:

a) Please see the response at Exhibit B.CCC.1.

The application of a cap and trade program is likely to target all fossils fuels. Union expects propane to be as much or more of a target than natural gas, since propane produces more emissions than natural gas. The U.S. Energy Information Administration indicates that propane produces 19% more pounds of CO2 per million British thermal units (Btu) of energy than natural gas, as noted on its website[1].

"Energy conservation is the right thing to do" and it should apply to all fuels.

[1] https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1
p. 3, lines 17-18
p. 32, lines 20-21
p. 33, lines 1-7
p. 40, lines 19-20
Appendix M

Union states in Appendix M that the average rate increase would be $3.88 per year. However, Union also claims that its proposal in this Application has been set to achieve the following objective, among others: "To limit the rate [increases] on existing customers to a maximum approximating $2 per month ($24 per year) over the multi-year expansion program." The existence of a deferral account as described on pages 32 and 33 suggests that the $24 per year cap is merely a target, not a real cap, and that any cost overruns or revenue shortfalls will be borne by existing customers, not Union shareholders.

a) If Union claims that its forecasted average rate increase is $3.88 per year, why has Union set a target cap of $24.00 per year (more than six times the forecasted average increase)?

b) If Union's forecasts are incorrect and the proposed rate increase exceeds $24 per year, who will absorb the excess costs – Union's shareholders, new customers, or existing customers?

c) Where is the answer to b) shown in Union's Application?

Response:

a) Please see the response at Exhibit B.CCC.2

b) Existing ratepayers would absorb the excess costs subject to Board approval through either the deferral account disposition process related to completed Projects, or through an application for rate recovery for any additional Projects. For additional Projects, Union will confirm that the cap of $24 per year is not being exceeded as part of the application for rate recovery for those Projects.

c) Information on the deferral accounts is provided at Exhibit A, Tab 1, pp. 32-33. Information on applications for additional Projects is provided at Exhibit A, Tab 1, p. 36.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1
p. 4, lines 1-3
p. 10, Figure 2
p. 11, lines 1-2

Union states at page 4 that the 30 proposed projects could serve 20,000 customers at a total capital cost of $150 million. Accordingly, it would cost $7,500 on average to connect a customer.

Union further states at page 11 that each new natural gas customer would save between $10,000 and $18,000 over a decade as a result of converting to natural gas. Accordingly, even if new customers pay an average of $7,500 in connection costs, they would still on average save thousands of dollars. At Figure 2, Union contends that such financial benefits can begin to accrue to a new customer at year 3.75.

a) Given these numbers, on what basis does Union contend that connection and conversion would be uneconomic for each new customer in the absence of a subsidy from existing ratepayers?

Response:

a) The assumption that customers who would have access to the system would be required to pay $7,500 in connection costs if the projects weren't otherwise financially supported is not a valid assumption. Union would not attempt to collect support from consumers unless they elect to attach to the system. Union would, if necessary, ask those attaching to pay an Aid-to-Construction ("CIAC"). Union has estimated 9,107 customer attachments for the potential 30 Projects. If the full $150 million was collected as CIAC, each customer would be required to pay $16,470. This figure does not recognize the value of the delivery revenue collected from those customers over the life of the assets.

   Assuming $16,470 in CIAC is required from each customer, Union does not believe many consumers would convert to natural gas. This is the reason that the government of Ontario is supporting efforts to take new approaches to extend the natural gas system to more rural and northern communities.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1
p. 10, Figure 2
p. 10, lines 6-9
p. 4, lines 1-3

Figure 2 appears to show the cumulative cost of natural gas service in Year 1 at approximately $7,500.[1].

The Year 1 cost of $7,500 is stated to be comprised of:

Replacement or conversion of equipment:	$4,000
Customer contributions-in-aid-of-construction:	$2,500
Annual Gas Delivery and Storage Costs	$1,000[2]
	$7,500

Although Union uses an assumed customer CAIC of $2,500 to arrive at these figures, Union states at page 4 that that the 30 proposed projects could serve 20,000 customers at a total capital cost of $150 million, which translates to $7,500 per customer, if fully funded by customer CAIC.

a) Provide a revised Figure 2 using at CAIC of $7,500 and Year 1 costs of $12,500 ($4,000 + $7,500 + $1,000) to show what the impact would be if new customers were to pay the full average capital cost, as opposed to just paying ⅓ of those costs.

b) In the current Figure 2, customers see a positive return on investment after 3.75 years. In the revised Figure 2 referred to in a), when would customers see a positive return on investment?

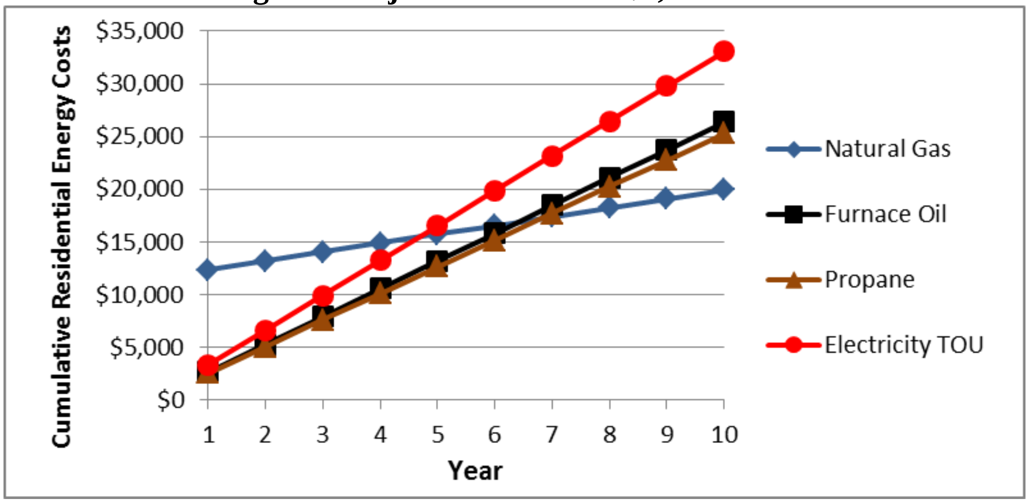
c) In the revised Figure 2 referred to in a), how much would a customer achieve in energy cost savings in the decade after connecting to the proposed natural gas expansion projects?

Notes: 1. The exact figure cannot be precisely determined by examining the chart as the scale is too small.
2. Presumably, the remaining cost in Year 1 is approximately $1,000 for the total annual cost of gas delivery and storage.

Response:

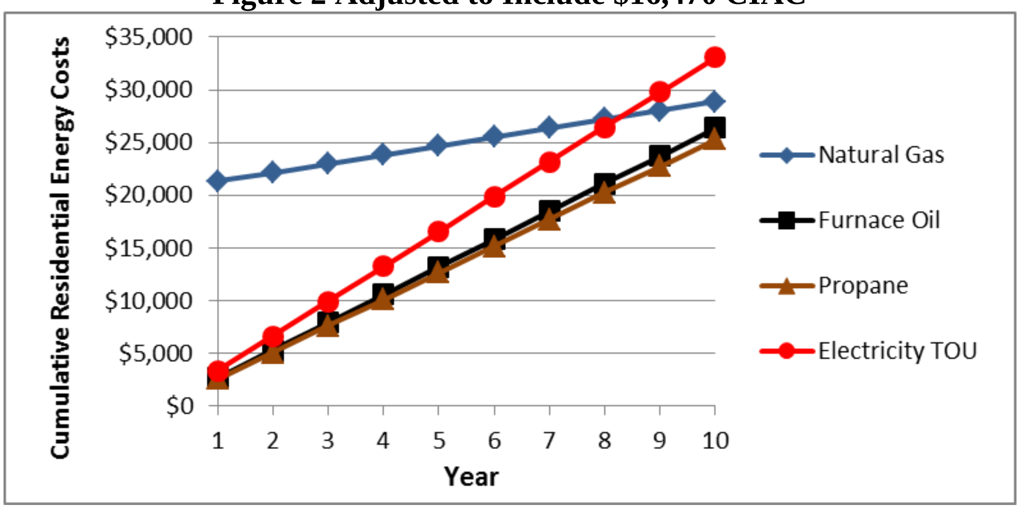
a) The year 1 annual commodity, transport, delivery and storage cost in Exhibit A, Tab 1, Figure 2, is $843. To be consistent Union has used this figure along with the requested assumptions in reproducing Figure 2 below.

Figure 2 Adjusted to Include $7,500 CIAC



However, the question assumes every consumer who would have access to the system would pay CIAC, which is unlikely. It is more likely that only those customers who convert (forecast customers) pay CIAC. In this case the CIAC would be $16,470.

Figure 2 Adjusted to Include $16,470 CIAC



b) Based on the charts above, customers would see a simple payback period ranging from 5 to 7 years if the assumption that all potential customers were to pay CIAC had merit. However, this is unlikely. In the case where all forecast customers (customers who connect) pay CIAC, the payback period would range from about 8 years to something over 10 years.

c) Based on the more likely scenario, which would require $16,470 in CIAC from every customer who connects, the savings would range from $4,180 to ($3,630) over the 10 year period.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, Appendix A, p.4

Union states that it filed this proposal in response to the Board's letter dated February 18, 2015, which is attached as Appendix "A" to Union's Application. The Letter sets out the following guidelines for applicants:

- "Proponents should develop proposals that, while ensuring safety and reliability, are ***cost effective*** and incorporate flexibility with respect to cost recovery (e.g. ROE, depreciation period, recovery of capital contribution, etc.).
- Proponents should develop proposals that include measures that foster ***predictability and cost certainty*** from a consumer perspective.
- Proponents should develop proposals that ***minimize impacts on existing natural gas ratepayers*** as a result of new expansion projects." [Emphasis added.]

a) How does Union's proposal satisfy the Board's guideline that any proposals should be "cost effective", when Union is proposing to move forward with projects that have a PI of as low as 0.4 (and lower than 0.4 when considered on their own merits in the absence of TES and ITE)? Is a project with a PI of 0.4 "cost effective"?

b) How does Union's proposal satisfy the Board's "predictability and cost certainty" guideline, when TES revenues and the increases to current customers' rates are entirely dependent on whether the attachment forecasts, in both volume and timing, are correct?

c) How does Union's proposal satisfy the requirement to "minimize impacts on existing natural gas ratepayers" when the obligations of *new* customers are fixed at \$0.23 per m^3, while the obligations of *existing* natural gas ratepayers are variable depending on actual costs and actual uptake, and can be as high as \$24/year or perhaps higher if Union shareholders will not take on any liability for excess costs or lower TES revenues?

Response:

a) The Board's invitation for proposals states that the Board may consider proposals that address whether projects that have "a P.I. lower than 0.8 should be considered"[1]. Union's proposal

[1] Exhibit A, Tab 1, Appendix A, p. 3.

that is consistent with the Board's invitation. Determining the cost effectiveness of a Project involves more than the P.I. outcome. In this case there are longer term benefits to expansion communities, ratepayers, and the province, that are not quantified in the economic feasibility assessment conducted for each project. Union summarizes these impacts at Exhibit B.CCC.5.

b) Union has taken a conservative approach to attachment forecasts, as outlined at Exhibit B.South Bruce.6. This approach mitigates risk of attachment forecast achievement. From the perspective of new customers in the Project communities, cost certainty will exist; they will know how much the TES costs and how long it will apply, and they will have the same level of certainty and predictability as other ratepayers with respect to their delivery rates. From the perspective of cost certainty for existing ratepayers, any forecast variances would be immaterial given the maximum impacts Union has designed its proposal to meet.

c) Union's proposal was designed to meet the government's desire to complete the maximum number of projects, and Union has applied its experience, judgment and regulatory precedent to also include a maximum ratepayer impact.

   The precedent referenced is the framework issued by the Board in 2014 which provide that the annual cost impact of Union's DSM programs be limited to a maximum of $2.00 per month for a typical residential ratepayer.[2] Union's proposal to limit the maximum ratepayer impact of a Community Expansion Program is entirely consistent with this figure.

   Union's conservative approach to forecasting noted in part b) above mitigates risk to ratepayers. In addition, Union's expenditures are routinely subject to a review of prudence by the Board. This approach should provide ratepayers with assurance that they will incur just and reasonable rates.

   Please see the response at Exhibit B.Staff.9 for additional detail.

[2] EB 2014-0134 Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 17, http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 12, lines 4-6

Union states that it has previously expanded to a new community requiring Board facilities approval - Red Lake.

For questions a) to f) below, provide separate responses for residential and commercial customers:

a) At the time that Union sought Board facilities approval for Red Lake, what did Union forecast would be (i) the number of customers that would attach; and (ii) the percentage of total potential customers that would attach in each year after the Red Lake facilities began operating?

b) What were (i) the number of customers; and (ii) the percentage of potential customers, that actually attached in Red Lake in each year after the Red Lake facilities began operating?

c) What was the estimated average cost of connecting from the property line to the meter for each Red Lake customer?

d) What was the actual average cost of connecting from the property line to the meter for Red Lake customers?

e) How were these costs paid?

f) How did the allocation and payment of these costs in Red Lake differ from Union's proposal in this Application?

g) Did any large industrial, commercial or institutional anchor loads play a role in the decision to expand to Red Lake? If so,

   i) Describe that role.

   ii) Would smaller retail and residential expansion have made sense in Red Lake if not for the anchor loads? Explain.

h) What are the anchor loads in the five projects for which Union is seeking leave to construct in this Application?

i) Did the municipality in Red Lake agree to pay an ITE?

j) If so, did the municipality in Red Lake rely on Union representatives to determine how much the municipality could expect to receive in incremental property taxes from the Red Lake pipeline project?

k) If so, what percentage of the ITE amount did Union predict could be paid using incremental property taxes from the Red Lake pipeline project?

l) What percentage of the ITE amount was actually paid using incremental property taxes from the Red Lake pipeline project?

m) How much did Union Gas forecast that Red Lake's municipality would receive from incremental property taxes from the Red Lake pipeline project in each year after the Red Lake pipeline project became operational?

n) If so, how much did Red Lake's municipality actually receive from incremental property taxes from the Red Lake pipeline project in each year after the Red Lake pipeline project became operational?

Response:

a) Please see the response at Exhibit B.Staff.14 c).

b) Please see the response at Exhibit B.Staff.14 c).

c) It is Union's policy to provide the first 30 metres of a service at no charge. Excess footage in excess of 30 metres is $45/metre.

d) The total cost for excess footage for all Red Lake customers was approximately $29,000.

e) The customer would pay their excess footage charges once connected.

f) There will be no difference in the allocation and payment of these costs between Red Lake and Union's current proposal.

g)
   i) Yes. Gold Corp Inc. paid an Aid-to-Construct of over $20 million dollars to facilitate construction of a pipeline to Red Lake.

   ii) No. The closest gas service to Red Lake was approximately 44 km south of Red Lake.

h) There are no anchor loads in the five projects.[1]

i) No. The Municipality of Red Lake did not pay an ITE but did provide a financial contribution to the project.

j) Not applicable.

k) Not applicable.

l) Not applicable.

m) As part of Union's Leave-to-Construct application for Red Lake (EB-2011-0040) at Schedule 4, p. 1, the estimated municipal tax for all the municipalities which the pipeline ran through was estimated to be $157,000.

n) The actual tax payments to Red Lake are shown in the table below:

Municipality of Red Lake

Property Tax Payments

	Amount Paid
	Total
2015	$ 93,727
2014	$ 88,963
2013	$ 91,936
TOTAL	**$274,626**

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 12, lines 8-19

Union claims that there are a number of advantages to converting to natural gas but provides no discussion of detriments to doing so.

a) Are there any detriments to converting to natural gas? Explain.

Response:

a) Relative to other fossil fuels, Union is not aware of any detriments of converting to natural gas. However, there are other benefits beyond what Union has included in Exhibit A, Tab 1, Section 3 such as:

   - Natural gas is lighter than air. In the event of a leak it dissipates into the air. In contrast, propane is heavier than air and will pool around the source of the leak. Oil will also pool around the source of the leak. Natural gas has a more limited combustible range than propane, so is less likely to be ignited. Natural gas has a higher lower explosive limit than oil, so it would be less likely to ignite in the case of a leak.
   - Natural gas produces less carbon emissions than propane or oil as noted in the response at Exhibit B.CPA.4.
   - Oil and propane require unsightly storage tanks, which are not required for natural gas.

   Relative to electricity, natural gas does cause more carbon emissions than electricity provided that 100% of the electricity is generated from renewable or nuclear sources, which is not the case in Ontario.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1
p. 19, lines 5-12
p. 20, lines 14-19
Appendix C, p. 25, para. 191

Union acknowledges that the TES amount ($0.23 per m^3) and term (4 years) are not dependent on how many people connect and when they do so. The rate of $0.23 per m^3 is based on a desired payback of 3.75 years. Further, the "TES will be terminated for every customer attached to the project, regardless of when the customer connected to the project."

a) If fewer potential customers connect than forecasted, or if they connect later in the TES period than forecasted, who is expected to pay the shortfall – Union shareholders, new customers, or current ratepayers?

b) If current ratepayers are expected to bear that financial burden, is there any commensurate financial risk that would be borne by Union shareholders and/or new customers?

c) How does the proposed risk allocation reflect the E.B.O. 188 principle (section 6.1.3) that "utility shareholders will be held responsible for any significant variation in the forecast of customer attachments, volumes and costs" – in other words, that Union shareholders, and not current ratepayers, should bear the risk of forecasting errors?

d) If Union shareholders will bear that risk, as contemplated by E.B.O. 188 principle, where is that commitment or obligation found?

e) Why is a simple payback period of 3.75 years (approximately equivalent to a 26% return on investment) necessary for Union's proposed new customers? Would Union consider a payback period of 7 to 10 years, or an ROI of 10-15%, to be an unreasonably low return for its proposed new customers? Explain.

Response:

a) One of Union's guiding principles[1] when designing the proposal is that moderate cross subsidization from existing customers is acceptable provided long-term rate impacts are reasonable. Union took a conservative approach to developing the forecast in order to

[1] Exhibit A, Tab 1, p.6

demonstrate the maximum rate impacts from its proposal. A more aggressive forecasting approach would reduce the future rate impacts, but may cause the Board to reconsider any potential approval should Union's actual experience be less than its forecast. However, on an actual basis, Union expects that its connections will exceed its conservative forecast, with further benefits to existing ratepayers. If the connections do not occur, or they occur later in the forecast period, and the Board viewed Union's related actions as prudent, current ratepayers would fund the difference.

A conservative connection forecast in the project economics serves to extend the term of the TES and ITE set for each project, and should as a result provide more upside than downside risk to ratepayers related to the attachment forecast.

b) One of Union's guiding principles when designing the proposal is that natural gas distributors should not be exposed to financial risk related to the incremental new community capital investments. Union's Community Expansion Project proposals are in direct response to the Ontario Energy Board's initiative to address the Ontario government's desire to expand natural gas distribution systems to communities that currently do not have access to natural gas. Union designed the proposal to minimize financial risk.

Furthermore, Union would not be pursuing this proposal in the absence of Ontario government direction to further expand natural gas service, and therefore should not take on or accept financial risk for responding to this direction. Finally, this approach is consistent with the capital pass-through mechanism in Union's IRM framework, where the utility earns precisely its allowed return on these investments during the term of the IRM.

New Community Expansion Project customers will bear the same risks as all other Union customers once they attach and become a customer of Union.

c) The principles and approach from E.B.O 188 do not, and cannot, apply to this proposal, which is why Union has requested an exemption from E.B.O 188. Should E.B.O 188 apply to this proposal, Union would not have advanced it. Union's proposal responds to the Ontario government's direction to expand natural gas service to remote and rural communities, and is consistent with its existing IRM framework.

The E.B.O. 188 decision was issued during a period that preceded the recent Ontario government's desire to expand natural gas distribution systems to underserved communities. Union's proposal requests exemptions from the underlying principles of E.B.O. 188, and as noted at Exhibit A, Tab 1, p.29, E.B.O. 188 provides for consideration of exemptions.

Union's expenditures are subject to an ongoing review of prudence by the Board. Union proposes to track the projects and report the results of the program to the Board and

Stakeholders on an annual basis[2]. This reporting will provide information for the Board to determine if Union's approach to Community Expansion Projects requires adjustment.

d) Union is not proposing to bear the risk of variation in the forecast of customer attachments, volumes and costs.

e) Typical customers do not think in terms of % ROI. Rather, customers consider payback period. In Union's view a seven to 10-year payback period is not likely to make Union's proposal successful. Please also see the response at Exhibit B.CCC.7.

[2] Exhibit A, Tab 1, p. 34, Section 6.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 22, lines 1-15
Exhibit A, Tab 1, Appendix D

Union proposes an ITE that "will be based on the estimated value of incremental property taxes collected from Union as a result of the project for a period of time that matches the term of the TES". However, there is no specific information about how the ITE would be calculated.

a) How would the "value of the incremental property taxes collected from Union" be calculated?

b) Based on the answer to a), how would the ITE amounts then be calculated?

c) What aggregate amount of ITE does Union expect to collect for each project?

d) How would Union ensure that municipal councils actually pay the ITE in the amount Union seeks, or at all?

e) How many of the proposed municipalities have agreed to pay the ITE, and how much has each agreed to pay? Provide evidence of all such agreements.

f) If the forecasted ITE is not collected in full for any reason, who will pay for the shortfall – Union shareholders, new customers, or current ratepayers? How is Union's response to this question consistent with the E.B.O. 188 principle (section 6.1.3) that Union shareholders, and not current ratepayers, should bear the risk of forecasting errors?

g) What is the amount of the ITE that will be required for each of (i) the five projects for which Union seeks leave to construct in this Application; and (ii) each of the other projects set out in Appendix "D"?

Response:

a) Union will apply the current Property Assessment Rates as established by the Ministry of Finance ("MoF"). These rates are used to calculate the assessed value of each proposed length of pipeline that is estimated to be used in the project. Once the assessed value is calculated, Union will then multiply the assessed value by the Pipeline Tax Rate (as published by that Municipality) to arrive at the estimated annual incremental property tax. MoF's assessment rates are provincially enacted through Regulation and are used universally across the Province; the assessment would be identical no matter where in the Province the plant is being installed. The variable in municipal assessments is the tax rate (mill rate) as tax rates can vary between municipalities.

b) Once Union pays the property tax invoice received from a new Community Expansion municipality, a corresponding ITE billing will be created and forwarded to the municipality.

With respect to First Nations taxation, Union will calculate the annual PILT (payment-in-lieu-of-taxes) amount due and remit payment to the First Nations group. Once Union makes the PILT payment, a corresponding ITE billing will be created and forwarded to the First Nations group for collection.

Once the ITE payment is received from the municipality or First Nations group, Union will record the amount received in the Community Expansion Contribution Deferral Account for refund to customers.

c) Please see the response at Exhibit B.LPMA.16.

d) Union will enter into a commercially binding agreement with the applicable municipality before commencing construction. Following that, Union will invoice the municipality for the relevant amount once each year. Union is confident its municipal partners will honour their agreements.

e) Union will initiate this process following the Board's Decision in this proceeding. Please see the response at Exhibit B.CCC.10.

f) The ITE will be treated similarly to the TES. The proposed Community Expansion Contribution Deferral Account will capture all ITE contributions from municipalities in order to allocate the revenue to ratepayers. Consequently, any positive or negative difference between forecast and actual ITE will be allocated to ratepayers. Please see the response at Exhibit B.CPA.11 c) and d) for details.

g) Please see the response at Exhibit B.LPMA.16.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 24, line 12

Union states that it "completed a high level analysis of potential projects identified in the Opportunity Assessment…", which is shown in Figure 4.

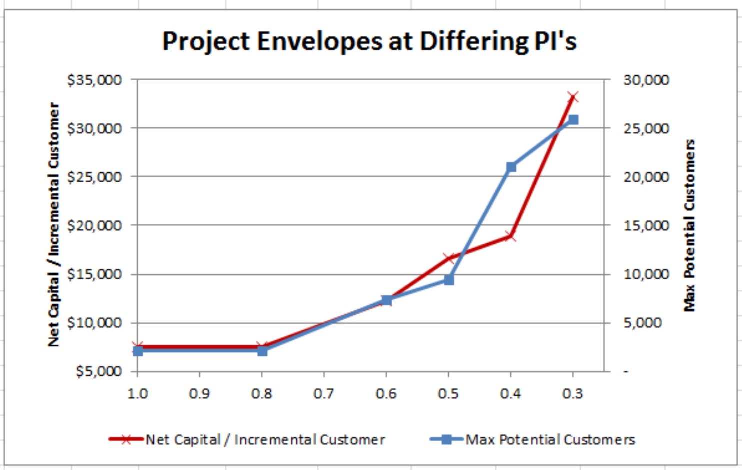
a) With respect to the "high level analysis", provide the complete analysis and raw data that purportedly supports the conclusions in Figure 4.

Response:

a) Please see the table below and also Attachment 1.

Project Envelopes at Differing PI's
Including TES/ITE but excluding any Provincial Funding

Minimum Project PI	Projects	Communities	Max Potential Customers	Forecast Customers ($0 Prov Funding)	Gross capital (millions)	Net Capital ($0 Prov Funding)	Rate Base not funded by exp customers	Annual Cost for exist res ratepayers ($0 Prov Funding)	Net Capital / Incremental Customer
1.0	4	5	2,176	1,004	$7.6	$7.6	$0.0	$0.00	$7,554
0.9									
0.8	4	5	2,176	1,004	$7.6	$7.6	$1.5	$0.16	$7,554
0.7									
0.6	14	15	7,365	3,382	$36.7	$36.7	$14.7	$1.57	$12,260
0.5	23	24	9,390	4,294	$51.8	$51.8	$25.9	$2.78	$16,558
0.4	31	35	21,101	9,572	$151.8	$151.8	$91.1	$9.76	$18,940
0.3	43	52	25,896	11,733	$223.5	$223.5	$156.5	$16.76	$33,182



						PI = 0.8		PI = 0.6		PI = 0.5		PI = 0.4		PI = 0.3	
Community Name	Communities	Maximum Customer Potential	Attachment Forecast	Inflated Cap Cost Excl Contr Load mains	Infl cap Cost/ Attachment	Cumulative Aid Required After TES/ITE PI= 0.8	Net Capital After TES/ITE and Prov Funding for PI= 0.8	Cumulative Aid Required After TES/ITE PI= 0.6	Net Capital After TES/ITE and Prov Funding for PI= 0.6	Cumulative Aid Required After TES/ITE PI= 0.5	Net Capital After TES/ITE and Prov Funding for PI= 0.5	Cumulative Aid Required After TES/ITE PI= 0.4	Net Capital After TES/ITE and Prov Funding for PI= 0.4	Cumulative Aid Required After TES/ITE PI= 0.3	Net Capital After TES/ITE and Prov Funding for PI= 0.3
Moraviantown First Nation- main commercial area	1	45	45	$ 293,232	$ 6,516	$ -	$ 293,232	$ -	$ 293,232	$ -	$ 293,232	$ -	$ 293,232	$ -	$ 293,232
Hornby	1	45	20	$ 133,924	$ 6,696	$ -	$ 133,924	$ -	$ 133,924	$ -	$ 133,924	$ -	$ 133,924	$ -	$ 133,924
Lambton Shores, Kettle Point First Nation	2	1620	729	$ 5,329,908	$ 7,311	$ -	$ 5,329,908	$ -	$ 5,329,908	$ -	$ 5,329,908	$ -	$ 5,329,908	$ -	$ 5,329,908
Prince Township, Sault Ste Marie	1	466	210	$ 1,827,218	$ 8,701	$ -	$ 1,827,218	$ -	$ 1,827,218	$ -	$ 1,827,218	$ -	$ 1,827,218	$ -	$ 1,827,218
Oneida First Nation	1	466	210	$ 2,199,300	$ 10,473	$ 202,200	$ 1,997,100	$ -	$ 2,199,300	$ -	$ 2,199,300	$ -	$ 2,199,300	$ -	$ 2,199,300
Walpole Island First Nation- main commercial area	1	70	70	$ 745,998	$ 10,657	$ 282,498	$ 665,700	$ -	$ 745,998	$ -	$ 745,998	$ -	$ 745,998	$ -	$ 745,998
Auburn	1	108	49	$ 526,770	$ 10,750	$ 343,279	$ 465,990	$ -	$ 526,770	$ -	$ 526,770	$ -	$ 526,770	$ -	$ 526,770
Cedar Springs	1	175	79	$ 896,175	$ 11,344	$ 488,163	$ 751,290	$ -	$ 896,175	$ -	$ 896,175	$ -	$ 896,175	$ -	$ 896,175
Milverton	1	1082	490	$ 5,573,796	$ 11,375	$ 1,402,059	$ 4,659,900	$ -	$ 5,573,796	$ -	$ 5,573,796	$ -	$ 5,573,796	$ -	$ 5,573,796
Lagoon City (Orillia)	1	2556	1150	$ 14,192,739	$ 12,342	$ 1,800,548	$ 13,794,250	$ -	$ 14,192,739	$ -	$ 14,192,739	$ -	$ 14,192,739	$ -	$ 14,192,739
Hidden Valley/Huntsville	1	100	46	$ 645,178	$ 14,026	$ 1,893,955	$ 551,770	$ -	$ 645,178	$ -	$ 645,178	$ -	$ 645,178	$ -	$ 645,178
Munsee Delaware First Nation	1	42	19	$ 269,321	$ 14,175	$ 1,982,586	$ 180,690	$ 18,141	$ 251,180	$ -	$ 269,321	$ -	$ 269,321	$ -	$ 269,321
Santa's Village/Beaumont Dr, Bracebridge	1	133	60	$ 860,491	$ 14,342	$ 2,123,377	$ 719,700	$ 18,141	$ 860,491	$ -	$ 860,491	$ -	$ 860,491	$ -	$ 860,491
Chippewa of the Thames First Nation- phase 3 & 4	1	110	50	$ 721,174	$ 14,423	$ 2,369,051	$ 475,500	$ 78,315	$ 661,000	$ -	$ 721,174	$ -	$ 721,174	$ -	$ 721,174
Sheffield	1	120	54	$ 779,468	$ 14,435	$ 2,634,979	$ 513,540	$ 143,903	$ 713,880	$ -	$ 779,468	$ -	$ 779,468	$ -	$ 779,468
Turkey Point	1	541	244	$ 3,699,580	$ 15,162	$ 4,014,119	$ 2,320,440	$ 617,803	$ 3,225,680	$ -	$ 3,699,580	$ -	$ 3,699,580	$ -	$ 3,699,580
Rockton	1	125	57	$ 883,944	$ 15,508	$ 4,355,993	$ 542,070	$ 748,207	$ 753,540	$ -	$ 883,944	$ -	$ 883,944	$ -	$ 883,944
Northshore Rd / Peninsula Rd North Bay	1	333	150	$ 2,340,977	$ 15,607	$ 4,897,720	$ 1,799,250	$ 748,207	$ 2,340,977	$ -	$ 2,340,977	$ -	$ 2,340,977	$ -	$ 2,340,977
Canal, Gravenhurst	1	166	74	$ 1,173,554	$ 15,859	$ 5,183,644	$ 887,630	$ 748,207	$ 1,173,554	$ -	$ 1,173,554	$ -	$ 1,173,554	$ -	$ 1,173,554
Chippewas of the Saugeen	1	120	54	$ 874,797	$ 16,200	$ 5,544,901	$ 513,540	$ 909,124	$ 713,880	$ -	$ 874,797	$ -	$ 874,797	$ -	$ 874,797
Belwood	1	768	346	$ 5,789,102	$ 16,732	$ 8,043,543	$ 3,290,460	$ 2,124,106	$ 4,574,120	$ 97,402	$ 5,691,700	$ -	$ 5,789,102	$ -	$ 5,789,102
Brenman Lin, Servern Twp (Gravenhurst)	1	33	14	$ 244,063	$ 17,433	$ 8,119,676	$ 167,930	$ 2,134,369	$ 233,800	$ 97,402	$ 244,063	$ -	$ 244,063	$ -	$ 244,063
Astorville	1	467	210	$ 3,713,218	$ 17,682	$ 9,313,943	$ 2,518,950	$ 2,340,587	$ 3,507,000	$ 97,402	$ 3,713,218	$ -	$ 3,713,218	$ -	$ 3,713,218
Nipissing First Nation / Jocko Point	1	467	210	$ 3,915,043	$ 18,643	$ 10,710,036	$ 2,518,950	$ 2,748,629	$ 3,507,000	$ 97,402	$ 3,915,043	$ -	$ 3,915,043	$ -	$ 3,915,043
Boblo Island	1	300	136	$ 2,662,471	$ 19,577	$ 12,079,147	$ 1,293,360	$ 3,613,180	$ 1,797,920	$ 522,673	$ 2,237,200	$ -	$ 2,662,471	$ -	$ 2,662,471
Swiss Meadow	1	108	49	$ 1,017,523	$ 20,766	$ 12,630,680	$ 465,990	$ 3,982,923	$ 647,780	$ 734,146	$ 806,050	$ -	$ 1,017,523	$ -	$ 1,017,523
Kincardine. Tiverton, Paisley, Chesley	4	9680	4361	$ 81,125,956	$ 18,603	$ 52,283,526	$ 41,473,110	$ 27,456,459	$ 57,652,420	$ 10,121,652	$ 71,738,450	$ -	$ 81,125,956	$ -	$ 81,125,956
Wroxieter/Gorrie/Fordwich	3	810	364	$ 8,057,531	$ 22,136	$ 56,879,417	$ 3,461,640	$ 30,701,910	$ 4,812,080	$ 12,191,382	$ 5,987,800	$ 140,531	$ 7,917,000	$ -	$ 8,057,531
Village of Warwick	1	150	69	$ 1,559,191	$ 22,597	$ 57,782,417	$ 656,190	$ 31,348,921	$ 912,180	$ 12,615,523	$ 1,135,050	$ 198,972	$ 1,500,750	$ -	$ 1,559,191
Washago	1	405	182	$ 4,144,046	$ 22,769	$ 59,743,374	$ 2,183,090	$ 32,453,567	$ 3,039,400	$ 12,983,069	$ 3,776,500	$ 198,972	$ 4,144,046	$ -	$ 4,144,046
E Floral (T Bay area)	1	100	46	$ 1,083,496	$ 23,554	$ 60,275,099	$ 551,770	$ 32,768,862	$ 768,200	$ 13,112,065	$ 954,500	$ 198,972	$ 1,083,496	$ -	$ 1,083,496
Latchford, Tri Town	1	200	90	$ 2,340,456	$ 26,005	$ 61,536,005	$ 1,079,550	$ 33,606,318	$ 1,503,000	$ 13,585,021	$ 1,867,500	$ 198,972	$ 2,340,456	$ -	$ 2,340,456
Haldimand Shores	1	150	68	$ 1,801,655	$ 26,495	$ 62,522,000	$ 815,660	$ 34,272,373	$ 1,135,600	$ 13,975,676	$ 1,411,000	$ 198,972	$ 1,801,655	$ -	$ 1,801,655
Neustadt	1	209	94	$ 2,519,116	$ 26,799	$ 64,147,176	$ 893,940	$ 35,548,809	$ 1,242,680	$ 14,948,491	$ 1,546,300	$ 673,587	$ 2,044,500	$ -	$ 2,519,116
Mohawks of the Bay of Quinte (aka Tyendinaga First Nation)	1	94	42	$ 1,225,910	$ 29,188	$ 64,869,296	$ 503,790	$ 36,073,319	$ 701,400	$ 15,302,902	$ 871,500	$ 746,597	$ 1,152,900	$ -	$ 1,225,910
Sioux Narrows / Nester Falls	2	1044	470	$ 14,113,663	$ 30,029	$ 73,345,308	$ 5,637,650	$ 42,337,982	$ 7,849,000	$ 19,664,064	$ 9,752,500	$ 1,958,760	$ 12,901,500	$ -	$ 14,113,663
Garden Village (Promenade-de-lac)	1	133	60	$ 1,803,491	$ 30,058	$ 74,429,099	$ 719,700	$ 43,139,472	$ 1,002,000	$ 20,222,555	$ 1,245,000	$ 2,115,251	$ 1,647,000	$ -	$ 1,803,491
Little Longlac	1	14	7	$ 250,344	$ 35,763	$ 74,595,478	$ 83,965	$ 43,272,916	$ 116,900	$ 20,327,648	$ 145,250	$ 2,173,444	$ 192,150	$ -	$ 250,344
Moose Creek	1	319	143	$ 5,481,046	$ 38,329	$ 78,361,238	$ 1,715,285	$ 46,365,861	$ 2,388,100	$ 22,841,444	$ 2,967,250	$ 3,729,140	$ 3,925,350	$ -	$ 5,481,046
Long Lake Phase 3, Sudbury	1	100	46	$ 1,804,953	$ 39,238	$ 79,614,421	$ 551,770	$ 47,402,614	$ 768,200	$ 23,691,897	$ 954,500	$ 4,271,392	$ 1,262,700	$ -	$ 1,804,953
Gores Landing	1	239	108	$ 4,315,740	$ 39,961	$ 82,634,700	$ 1,295,460	$ 49,914,754	$ 1,803,600	$ 25,766,636	$ 2,241,000	$ 5,622,532	$ 2,964,600	$ -	$ 4,315,740
Emsdale Muskoka	1	33	14	$ 560,313	$ 40,022	$ 83,027,083	$ 167,930	$ 50,241,267	$ 233,800	$ 26,036,449	$ 290,500	$ 5,798,545	$ 384,300	$ -	$ 560,313
Consecon- Ameliasburgh, Rossmore	3	1650	744	$ 30,014,064	$ 40,341	$ 104,116,868	$ 8,924,280	$ 67,830,531	$ 12,424,800	$ 40,612,513	$ 15,438,000	$ 15,389,809	$ 20,422,800	$ -	$ 30,014,064
Keast and South Bay Rd, Sudbury	1	100	46	$ 1,904,428	$ 41,401	$ 105,469,525	$ 551,770	$ 68,966,758	$ 768,200	$ 41,562,441	$ 954,500	$ 16,031,537	$ 1,262,700	$ 41,428	$ 1,863,000
Wabauskang First Nation	1	161	72	$ 3,115,329	$ 43,268	$ 107,721,215	$ 863,640	$ 70,879,688	$ 1,202,400	$ 43,183,770	$ 1,494,000	$ 17,170,466	$ 1,976,400	$ 240,757	$ 2,916,000
Cherry Valley	1	161	72	$ 3,123,039	$ 43,376	$ 109,980,614	$ 863,640	$ 72,800,327	$ 1,202,400	$ 44,812,810	$ 1,494,000	$ 18,317,105	$ 1,976,400	$ 447,796	$ 2,916,000
St Charles, Sudbury	1	427	192	$ 8,536,711	$ 44,462	$ 116,214,285	$ 2,303,040	$ 78,130,638	$ 3,206,400	$ 49,365,521	$ 3,984,000	$ 21,583,417	$ 5,270,400	$ 1,208,507	$ 7,776,000
Spencerville	1	317	142	$ 6,319,519	$ 44,504	$ 120,830,514	$ 1,703,290	$ 82,078,757	$ 2,371,400	$ 52,738,540	$ 2,946,500	$ 24,005,036	$ 3,897,900	$ 1,777,026	$ 5,751,000
Alderville, Roseneath (Incl Alderville FN)	2	265	119	$ 5,951,333	$ 50,011	$ 125,354,442	$ 1,427,405	$ 86,042,790	$ 1,987,300	$ 56,220,622	$ 2,469,250	$ 26,689,818	$ 3,266,550	$ 2,908,859	$ 4,819,500
Augusta Township	1	95	42	$ 2,149,231	$ 51,172	$ 126,999,883	$ 503,790	$ 87,490,621	$ 701,400	$ 57,498,354	$ 871,500	$ 27,686,150	$ 1,152,900	$ 3,357,090	$ 1,701,000
Nobel (Parry Sound)	1	221	100	$ 5,988,151	$ 59,882	$ 131,788,534	$ 1,199,500	$ 91,808,772	$ 1,670,000	$ 61,411,505	$ 2,075,000	$ 30,929,301	$ 2,745,000	$ 5,295,242	$ 4,050,000
Remi Lake area - north of Moonbeam	1	444	200	$ 12,428,625	$ 62,143	$ 141,818,159	$ 2,399,000	$ 100,897,397	$ 3,340,000	$ 69,690,130	$ 4,150,000	$ 37,867,926	$ 5,490,000	$ 9,623,867	$ 8,100,000
Chukuni Subdivision (Red Lake area)	1	97	43	$ 2,738,219	$ 63,680	$ 144,040,593	$ 515,785	$ 102,917,516	$ 718,100	$ 71,536,099	$ 892,250	$ 39,425,795	$ 1,180,350	$ 10,620,586	$ 1,741,500
Ripley,Lucknow	2	896	403	$ 26,344,193	$ 65,370	$ 166,552,256	$ 3,832,530	$ 123,934,049	$ 5,327,660	$ 91,250,942	$ 6,629,350	$ 57,004,738	$ 8,765,250	$ 24,068,779	$ 12,896,000
Redbridge	1	100	46	$ 3,186,678	$ 69,276	$ 169,187,164	$ 551,770	$ 126,352,527	$ 768,200	$ 93,483,120	$ 954,500	$ 58,928,715	$ 1,262,700	$ 25,392,456	$ 1,863,000

Sydenham, Harrowsmith, Verona	3	1117	502	$ 35,057,959	$ 69,837	$ 198,223,632	$ 6,021,490	$ 153,027,086	$ 8,383,400	$ 118,124,578	$ 10,416,500	$ 80,206,774	$ 13,779,900	$ 40,119,415	$ 20,331,000
Gillies (outside Thunder Bay)	1	75	33	$ 2,343,482	$ 71,015	$ 200,171,279	$ 395,835	$ 154,819,467	$ 551,100	$ 119,783,310	$ 684,750	$ 81,644,405	$ 905,850	$ 41,126,396	$ 1,336,500
Inverary	1	200	91	$ 7,111,356	$ 78,147	$ 206,191,090	$ 1,091,545	$ 160,411,123	$ 1,519,700	$ 125,006,416	$ 1,888,250	$ 86,257,812	$ 2,497,950	$ 44,552,252	$ 3,685,500
Thomasburg	1	140	63	$ 4,925,304	$ 78,179	$ 210,360,709	$ 755,685	$ 164,284,327	$ 1,052,100	$ 128,624,470	$ 1,307,250	$ 89,453,765	$ 1,729,350	$ 46,926,056	$ 2,551,500
Loon Lake (outside of Thunder Bay)	1	175	79	$ 6,494,602	$ 82,210	$ 215,907,706	$ 947,605	$ 169,459,629	$ 1,319,300	$ 133,479,822	$ 1,639,250	$ 93,779,817	$ 2,168,550	$ 50,221,158	$ 3,199,500
Webbwood and McKerrow + Massey	3	524	236	$ 20,815,565	$ 88,202	$ 233,892,451	$ 2,830,820	$ 186,333,994	$ 3,941,200	$ 149,398,387	$ 4,897,000	$ 108,117,182	$ 6,478,200	$ 61,478,723	$ 9,558,000
Centenial Cres, North Bay	1	100	46	$ 4,436,728	$ 96,451	$ 237,777,408	$ 551,770	$ 190,002,522	$ 768,200	$ 152,880,614	$ 954,500	$ 111,291,210	$ 1,262,700	$ 64,052,451	$ 1,863,000
Thunder Lake & Meadows (Dryden area)	1	206	92	$ 9,014,609	$ 97,985	$ 245,688,477	$ 1,103,540	$ 197,480,730	$ 1,536,400	$ 159,986,223	$ 1,909,000	$ 117,780,418	$ 2,525,400	$ 69,341,059	$ 3,726,000
Charlton NW of Englehart	1	63	29	$ 2,845,958	$ 98,136	$ 248,186,580	$ 347,855	$ 199,842,388	$ 484,300	$ 162,230,431	$ 601,750	$ 119,830,327	$ 796,050	$ 71,012,518	$ 1,174,500
Goulais River and Goulais Bay	2	333	150	$ 15,059,977	$ 100,400	$ 261,447,307	$ 1,799,250	$ 212,397,365	$ 2,505,000	$ 174,177,908	$ 3,112,500	$ 130,772,804	$ 4,117,500	$ 79,997,494	$ 6,075,000
Westport	1	1188	536	$ 55,801,661	$ 104,108	$ 310,819,648	$ 6,429,320	$ 259,247,826	$ 8,951,200	$ 218,857,568	$ 11,122,000	$ 171,861,264	$ 14,713,200	$ 114,091,155	$ 21,708,000
Bancroft	1	1896	854	$ 89,334,620	$ 104,607	$ 389,910,537	$ 10,243,730	$ 334,320,646	$ 14,261,800	$ 290,471,688	$ 17,720,500	$ 237,753,584	$ 23,442,300	$ 168,838,775	$ 34,587,000
King Kirkland + Larder Lake + Virginiatown + Kearns	4	1014	458	$ 48,359,614	$ 105,589	$ 432,776,441	$ 5,493,710	$ 375,031,659	$ 7,648,600	$ 329,327,802	$ 9,503,500	$ 273,541,098	$ 12,572,100	$ 198,649,389	$ 18,549,000
Sioux Lookout + Hudson + Lac Seul FN + Fisherman's Head	4	2814	1268	$ 134,432,473	$ 106,019	$ 551,999,255	$ 15,209,660	$ 488,288,533	$ 21,175,600	$ 437,449,275	$ 26,311,000	$ 373,166,971	$ 34,806,600	$ 281,727,862	$ 51,354,000
Roblin, Marbank	2	204	92	$ 9,757,023	$ 106,055	$ 560,652,737	$ 1,103,540	$ 496,509,155	$ 1,536,400	$ 445,297,298	$ 1,909,000	$ 380,398,594	$ 2,525,400	$ 287,758,885	$ 3,726,000
Red Rock First Nation - Lake Helen	1	100	46	$ 5,098,399	$ 110,835	$ 565,199,366	$ 551,770	$ 500,839,354	$ 768,200	$ 449,441,197	$ 954,500	$ 384,234,292	$ 1,262,700	$ 290,994,283	$ 1,863,000
Back Rd- Timmins area	1	126	57	$ 6,775,156	$ 118,862	$ 571,290,807	$ 683,715	$ 506,662,610	$ 951,900	$ 455,033,603	$ 1,182,750	$ 389,444,798	$ 1,564,650	$ 295,460,939	$ 2,308,500
Lac St-Therese (north of Hearst)	1	119	54	$ 6,995,280	$ 129,542	$ 577,638,357	$ 647,730	$ 512,756,090	$ 901,800	$ 460,908,382	$ 1,120,500	$ 394,957,778	$ 1,482,300	$ 300,269,219	$ 2,187,000
Field	1	100	46	$ 6,021,428	$ 130,901	$ 583,108,014	$ 551,770	$ 518,009,317	$ 768,200	$ 465,975,310	$ 954,500	$ 399,716,506	$ 1,262,700	$ 304,427,646	$ 1,863,000
Slate River (outside Thunder Bay)	1	300	136	$ 18,114,133	$ 133,192	$ 599,590,827	$ 1,631,320	$ 533,852,250	$ 2,271,200	$ 481,267,443	$ 2,822,000	$ 414,097,439	$ 3,733,200	$ 317,033,779	$ 5,508,000
Hagar	1	70	31	$ 4,172,782	$ 134,606	$ 603,391,764	$ 371,845	$ 537,507,333	$ 517,700	$ 484,796,975	$ 643,250	$ 417,419,271	$ 850,950	$ 319,951,062	$ 1,255,500
Rosseau (Parry Sound)	1	100	47	$ 6,561,928	$ 139,615	$ 609,389,927	$ 563,765	$ 543,284,360	$ 784,900	$ 490,383,653	$ 975,250	$ 422,691,049	$ 1,290,150	$ 324,609,489	$ 1,903,500
Wahnapitae First Nation	1	130	59	$ 8,554,704	$ 144,995	$ 617,236,926	$ 707,705	$ 550,853,764	$ 985,300	$ 497,714,107	$ 1,224,250	$ 429,626,202	$ 1,619,550	$ 330,774,693	$ 2,389,500
Lavigne	1	66	30	$ 4,466,745	$ 148,892	$ 621,343,821	$ 359,850	$ 554,819,509	$ 501,000	$ 501,558,352	$ 622,500	$ 433,269,448	$ 823,500	$ 334,026,438	$ 1,215,000
Town of Wabigoon + Wabigoon First Nation	2	254	114	$ 18,094,697	$ 158,725	$ 638,071,088	$ 1,367,430	$ 571,010,406	$ 1,903,800	$ 517,287,549	$ 2,365,500	$ 448,234,845	$ 3,129,300	$ 347,504,135	$ 4,617,000
O'Connor (Outside Thunder Bay)	1	275	123	$ 21,180,516	$ 172,199	$ 657,776,219	$ 1,475,385	$ 590,136,822	$ 2,054,100	$ 535,915,815	$ 2,552,250	$ 466,039,011	$ 3,376,350	$ 363,703,151	$ 4,981,500
Terrace Bay + Schrieber + Marathon	3	3109	1400	$ 243,996,397	$ 174,283	$ 884,979,616	$ 16,793,000	$ 810,753,219	$ 23,380,000	$ 750,862,212	$ 29,050,000	$ 671,605,408	$ 38,430,000	$ 550,999,548	$ 56,700,000
Conmee (outside Thunder Bay)	1	150	68	$ 12,006,817	$ 176,571	$ 896,170,772	$ 815,660	$ 821,624,436	$ 1,135,600	$ 761,458,028	$ 1,411,000	$ 681,745,624	$ 1,866,600	$ 560,252,365	$ 2,754,000
Algoma Mills + Spragge + Serpent River + Spanish	4	413	189	$ 35,722,389	$ 189,007	$ 929,626,107	$ 2,267,055	$ 854,190,525	$ 3,156,300	$ 793,258,668	$ 3,921,750	$ 712,279,963	$ 5,188,050	$ 588,320,254	$ 7,654,500
Camden East, Yarker, Tamworth, Erinsville	4	636	289	$ 54,697,957	$ 189,266	$ 980,857,508	$ 3,466,555	$ 904,062,182	$ 4,826,300	$ 841,959,874	$ 5,996,750	$ 759,044,870	$ 7,933,050	$ 631,313,711	$ 11,704,500
Nolalu (outside Thunder Bay)	1	75	33	$ 7,723,912	$ 234,058	$ 988,185,585	$ 395,835	$ 911,234,993	$ 551,100	$ 848,999,036	$ 684,750	$ 765,862,932	$ 905,850	$ 637,701,122	$ 1,336,500
Dorion (outside Thunder Bay)	1	30	13	$ 3,348,007	$ 257,539	$ 991,377,657	$ 155,935	$ 914,365,900	$ 217,100	$ 852,077,292	$ 269,750	$ 768,854,088	$ 356,850	$ 640,522,629	$ 526,500
Marks Township (outside Thunder Bay)	1	30	13	$ 3,425,632	$ 263,510	$ 994,647,353	$ 155,935	$ 917,574,431	$ 217,100	$ 855,233,174	$ 269,750	$ 771,922,870	$ 356,850	$ 643,421,760	$ 526,500
Whitefish River	1	145	66	$ 18,251,008	$ 276,530	$ 1,012,106,691	$ 791,670	$ 934,723,239	$ 1,102,200	$ 872,114,682	$ 1,369,500	$ 788,362,177	$ 1,811,700	$ 658,999,768	$ 2,673,000
Kaministiquia	1	66	30	$ 8,483,838	$ 282,795	$ 1,020,230,678	$ 359,850	$ 942,706,077	$ 501,000	$ 879,976,019	$ 622,500	$ 796,022,515	$ 823,500	$ 666,268,606	$ 1,215,000
Bala Muskoka	1	133	60	$ 17,104,241	$ 285,071	$ 1,036,615,219	$ 719,700	$ 958,808,317	$ 1,002,000	$ 895,835,260	$ 1,245,000	$ 811,479,756	$ 1,647,000	$ 680,942,846	$ 2,430,000
Dorset	1	133	60	$ 19,519,241	$ 325,321	$ 1,055,414,760	$ 719,700	$ 977,325,558	$ 1,002,000	$ 914,109,501	$ 1,245,000	$ 829,351,996	$ 1,647,000	$ 698,032,087	$ 2,430,000
Jogues (south of Hearst) **NEW PRICING	1	77	34	$ 12,564,095	$ 369,532	$ 1,067,571,025	$ 407,830	$ 989,321,853	$ 567,800	$ 925,968,096	$ 705,500	$ 840,982,791	$ 933,300	$ 709,219,182	$ 1,377,000
Madsen	1	87	39	$ 16,246,027	$ 416,565	$ 1,083,349,247	$ 467,805	$ 1,004,916,580	$ 651,300	$ 941,404,873	$ 809,250	$ 856,158,268	$ 1,070,550	$ 723,885,709	$ 1,579,500
Arnstein + Port Loring	2	143	64	$ 33,943,139	$ 530,362	$ 1,116,524,706	$ 767,680	$ 1,037,790,919	$ 1,068,800	$ 974,020,011	$ 1,328,000	$ 888,344,607	$ 1,756,800	$ 755,236,848	$ 2,592,000
Nippising Village + Restoule	2	66	30	$ 18,243,745	$ 608,125	$ 1,134,408,601	$ 359,850	$ 1,055,533,664	$ 501,000	$ 991,641,257	$ 622,500	$ 905,764,852	$ 823,500	$ 772,265,593	$ 1,215,000
Hoyle	1	25	11	$ 7,727,161	$ 702,469	$ 1,142,003,816	$ 131,945	$ 1,063,077,125	$ 183,700	$ 999,140,167	$ 228,250	$ 913,190,063	$ 301,950	$ 779,547,254	$ 445,500
Hilton Beach	1	48	21	$ 15,678,867	$ 746,613	$ 1,157,430,789	$ 251,895	$ 1,078,405,292	$ 350,700	$ 1,014,383,284	$ 435,750	$ 928,292,480	$ 576,450	$ 794,375,621	$ 850,500
Aroland/Nakina	2	200	92	$ 79,242,109	$ 861,327	$ 1,235,569,358	$ 1,103,540	$ 1,156,111,001	$ 1,536,400	$ 1,091,716,394	$ 1,909,000	$ 1,005,009,189	$ 2,525,400	$ 869,891,730	$ 3,726,000
Whitefish Falls	1	31	14	$ 14,130,313	$ 1,009,308	$ 1,249,531,741	$ 167,930	$ 1,170,007,514	$ 233,800	$ 1,105,556,207	$ 290,500	$ 1,018,755,203	$ 384,300	$ 883,455,043	$ 567,000
Baysville Muskoka	1	33	14	$ 14,584,563	$ 1,041,755	$ 1,263,948,374	$ 167,930	$ 1,184,358,277	$ 233,800	$ 1,119,850,270	$ 290,500	$ 1,032,955,466	$ 384,300	$ 897,472,607	$ 567,000
Mactier (Parry Sound)	1	33	14	$ 18,868,313	$ 1,347,737	$ 1,282,648,757	$ 167,930	$ 1,202,992,791	$ 233,800	$ 1,138,428,083	$ 290,500	$ 1,051,439,479	$ 384,300	$ 915,773,920	$ 567,000
McKenzie Island	1	80	36	$ 49,046,258	$ 1,362,396	$ 1,331,263,195	$ 431,820	$ 1,251,437,849	$ 601,200	$ 1,186,727,341	$ 747,000	$ 1,099,497,537	$ 988,200	$ 963,362,178	$ 1,458,000
TOTALS for displayed projects	**138**	**46,612**	**21,072**	**$ 1,561,676,107**											

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1
p. 25, lines 6-7
p. 35, line 17
Figure 4, p. 25

The analysis shown in Figure 4 is based on "potential customers", not expected actual customers. Similarly, at page 35, Union states that "the criteria to be considered for each project will include … the number of potential customers…".

a) Why does Union consider the maximum number of potential customers in the area to be more relevant than the number of expected or forecasted actual customers when assessing projects?

b) Provide a revised Figure 4 that is based on forecasted actual customers instead of potential customers.

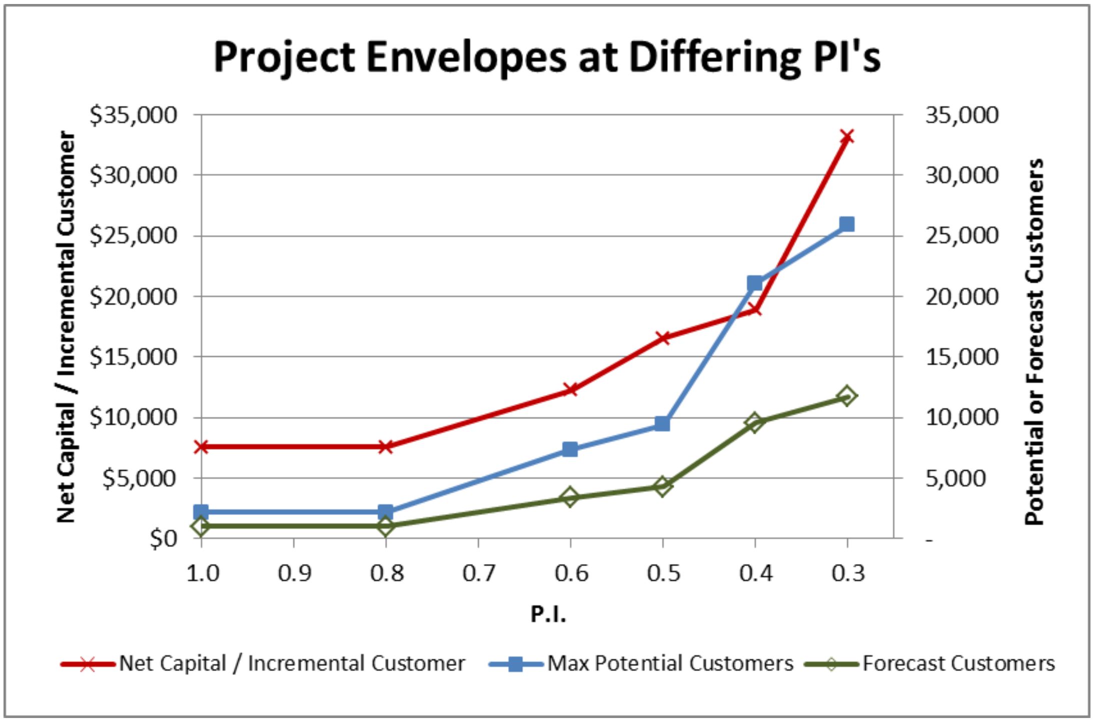
Response:

a) The number of potential customers is relevant to the proposal because the government has a goal to "provide consumers in underserved communities more energy choices…" as noted in Premier Wynne's mandate letters[1] to the Minister of Energy, the Minister of Economic Development, Employment and Infrastructure, and the Minister of Agriculture, Food, and Rural Affairs. Consumers include more than only those that elect to convert to natural gas in the 10 year customer forecast period used in economic feasibility studies for these Projects. As noted at Exhibit B.CCC.5, Union expects further attachments following the initial 10 year period.

   The "Net Capital per Incremental Customer" in Exhibit A, Tab 1, Figure 2, is the capital required to attach the incremental forecast customers at each reduced Project minimum P.I. level. It is not the net capital per potential customer.

b) Please see the chart below.

[1] All letters are included in Exhibit A, Tab 1, Appendix N.


Project Envelopes at Differing PI's
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
Net Capital / Incremental Customer
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
Potential or Forecast Customers
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
P.I.
Net Capital / Incremental Customer
Max Potential Customers
Forecast Customers

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 29, lines 14-16

Union's analysis states that "completing the five projects would result in Union's IP decreasing to 1.02 for Union South, which is below the minimum target of 1.1."

a) If there are cost overruns for the projects, what amount of cost overruns would result in Union's IP for Union South decreasing below 1.0?

b) What percentage of forecasted actual customers need to attach to each project in order to prevent Union's IP for Union South from decreasing below 1.0?

c) What would Union's IP for Union South be if Union's forecasted actual customers for each project attach one, two, or three years later than forecasted?

Response:

a) The P.I. of 1.02 (Union South) would be revised to 1.03 excluding the Walpole Island First Nations project that Union has withdrawn[1]. The first year capital cost of the four proposed projects used in the estimate of the Investment Portfolio ("IP") of 1.03 is $6.1 million. A P.I. of 1.0 for the IP would occur if the first year cost for the four projects was $7.5 million.

b-c) The question posed is not relevant to the Investment Portfolio (IP) as the underlying assumption would require that the attachments for the Projects occur in a pattern that would be unrealistic. More specifically:

- Part b) would require a back calculation to accelerate multiple years of future attachments into year 1 in order to answer the question. This is not a realistic scenario.
- Part c) asks for year 1 customers to be delayed until year 2 or later, in which case for the IP there would be a cost for main and zero customers. Union would not undertake the Project if such scenario was realistic.

To clarify, the IP is a single year assessment of the capital cost of connecting all customers to Union's system in only that single year and the future revenue stream from only the attachments made in that same year. The capital costs included in the IP include the cost of attaching customers where installation of new gas main is necessary, plus the cost of attaching

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

customers on existing main in areas where main previously existed (e.g. main installed one or more years prior). In the IP the attachments for the four proposed Projects only include the year 1 forecasted customers.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 31, lines 18-20
Exhibit A, Tab 1, Appendix C, p. 25, para. 191

Union states that its "proposal is consistent with the principle that Gas Distributors should not be exposed to financial risk related to the incremental capital investment required for Community Expansion Projects."

a) Where is this principle specified in law, regulations, policy, or any energy board decision?

b) Does this principle suggest that Gas Distributors should *never* be exposed to financial risk related to the incremental capital investment required for Community Expansion Projects? If not, then when should Gas Distributors be exposed to such financial risk?

c) Advise how this principle is consistent with the principle set out by the OEB in section 6.1.3 of E.B.O 188 that utility shareholders should bear the risk of forecasting errors?

d) Does Union accept that if there is a principle that Gas Distributors should not be exposed to financial risk, that it must be balanced by the corresponding principle that a Gas Distributor should not invest in overly risky or unprofitable projects when someone else is bearing all or most of the financial risk?

Response:

a) This principle is not specified in law, regulations, policy, or any Board Decisions. The principles defined at Exhibit A, Tab 1, p. 6 are principles that Union set and attempted to balance in the development of its proposal. With approval of its proposal, Union will continue to be exposed to the same risks that it is generally exposed to in running the LDC business on an ongoing basis. The key financial risks that Union had in mind in developing its proposal were as follows:

- The capital required for a Community Expansion Program is incremental to the utility's routine expected capital program each year, and was not anticipated at the time the current Incentive Regulation ("IR") Framework was developed. Without approval for a capital pass-through, Union would be unable to manage this incremental investment within its existing price cap framework, and accordingly would not make this investment.

- Union is unwilling to bear the forecast attachment risk because the TES for these projects is much more significant than for Community Expansion Projects Union has completed in the past.

b) Please see the response to a).

c) This principle is not consistent nor is it intended to be consistent. As noted at Exhibit A, Tab 1, p.8, the E.B.O.188 Decision was implemented during a period of time that preceded the recent provincial policy goal of providing customers in underserved communities more energy choices. The E.B.O. 188 principle does not work for this purpose.

d) The intent of Union's Community Expansion proposal is to provide a balanced approach to allow for expansion that provides access to the greatest possible number of communities while ensuring rate impact for existing customers is reasonable. Should Union's proposal be approved, the risks of the incremental investments would be no different than those associated with Union's regulated utility business.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 38, lines 8-10

Union assumes an attachment rate of 80% over 25 years and 47% over 10 years in carrying out its Stage 2 analysis: "The attachment rate is 80% of the market potential over an attachment term of 25 years. The 10 year forecast period attachment rate is 47% with the remaining 33% occurring over the following 15 years."

a) Provide the data, assumptions, calculations, and any source documents that Union used to determine that the 80% and 47% attachment rates should be used in the Stage 2 analysis.

b) Throughout the Application, Union assumes a TES period of four years. However, in the references section, Union cites and considers the 10 and 25 year attachment rates, instead of providing the four year rate. Provide a revised Stage 2 analysis based on attachment and savings applicable over the first four years.

Response:

a) The five proposed Projects have a Project specific attachment rate as detailed in their respective schedules.[1] The other Projects in Exhibit A, Tab 1, Appendix D are based on 45% over 10 years unless better information was available. The 47% referenced in the question is the average for 30 Projects. The 80% is a conservative estimate for longer term gas penetration. Where Union has gas service the pre-dominate fuel choice by customers is gas with a gas penetration rate of approximately 90%[2]. After 25 years Union expects the gas penetration for the proposed Projects to be similar to existing gas serviced areas. The 80% was used as an indication of the relative magnitude of Stage 2 saving using a conservative penetration rate.

b) The Stage 2 calculations used the TES periods noted in Exhibit A, Tab 1, Appendix D. Union's proposal is for a minimum TES term of 4 years. A Stage 2 calculation limited to four years of attachments would be misleading and not relevant to the proposal.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

[2] Union's current penetration rate of single family homes that are adjacent to the natural gas system is 90% based on Union Gas 2011 Market Share study, provided at Exhibit B.SEC.9.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 38, lines 4-5

Union claims that its Stage 2 analysis shows that potential customers could have net energy savings if they had access to natural gas.

a) Provide all data, the source of the data and the calculations and assumptions relied upon, including those involving gas and propane prices, used in the Stage 2 analysis.

b) Does the propane price information relied upon by Union in its Stage 2 analysis relate to auto propane (used for vehicles) or heating propane (used for residential and commercial heating purposes)?

Response:

a) The equipment costs are listed at Exhibit A, Tab 1, Table 2, p. 19.

Please see the response at Exhibit B.CPA.1, Attachment 1 for fuel prices.
The TES and ITE are based on Union's Community Expansion proposal detailed in Exhibit A, Tab 1.

Attachment 1 illustrates the Stage 2 calculation.

b) Please see the response at Exhibit B.CPA.2.

Stage 2 Summary

Summary: Energy Savings $ 000's at Mkt share of 80.0%

Line		South	Term	Term	Term
		(a)	(b)	(c)	(d)
1	Discount Rate	5.0%	15	30	40
2	Discount Rate	10.0%			
3	NPV discounted at 5.0%		79,115	188,105	233,379
4	NPV discounted at 10.0%		48,814	87,628	96,551
		North	Term	Term	Term
6	Discount Rate	5.0%	15	30	40
7	Discount Rate	10.0%			
8	NPV discounted at 5.0%		32,838	73,590	90,518
9	NPV discounted at 10.0%		20,634	35,147	38,483
		North + South	15	30	40
10	NPV discounted at 5.0%		111,953	261,695	323,897
11	NPV discounted at 10.0%		69,447	122,775	135,035

Table 1

Stage 2--Energy Cost Savings: South

Line	Weighting	Fuel	Equipment	Estimated Conversion Cost	Alt Fuel Cost	Gas Cost	Annual Fuel Savings
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	32.2%	Oil	Boiler	4,200	2,644	759	1,886
2	2.8%	Oil	Forced Air	4,200	2,644	759	1,886
3	1.2%	Propane	Boiler	4,000	2,438	759	1,679
4	11.7%	Propane	Forced Air	1,525	2,438	759	1,679
5	2.1%	Propane	Space Heater	3,500	2,438	759	1,679
6	6.3%	Electric	Baseboard	11,000	3,061	759	2,303
7	12.0%	Electric	Forced Air	4,000	3,061	759	2,303
8	3.8%	Electric	Heat Pump	4,000	3,061	759	2,303
9	28.0%	Wood	Wood Stove	3,500	1,572	759	813
10		Weighted Average		4,068	2,405	759	1,646

Stage 2--Energy Cost Savings: North

Line	Weighting	Fuel	Equipment	Estimated Conversion Cost	Alt Fuel Cost	Gas Cost	Annual Fuel Savings
11	32.2%	Oil	Boiler	4,200	2,610	1,097	1,512
12	2.8%	Oil	Forced Air	4,200	2,610	1,097	1,512
13	1.2%	Propane	Boiler	4,000	2,794	1,097	1,696
14	11.7%	Propane	Forced Air	1,525	2,794	1,097	1,696
15	2.1%	Propane	Space Heater	3,500	2,794	1,097	1,696
16	6.3%	Electric	Baseboard	11,000	2,891	1,097	1,794
17	12.0%	Electric	Forced Air	4,000	2,891	1,097	1,794
18	3.8%	Electric	Heat Pump	4,000	2,891	1,097	1,794
19	28.0%	Wood	Wood Stove	3,500	1,572	1,097	475
20		Weighted Average		4,068	2,409	1,097	1,311

Line	**Table 2 : TES Cost**				
1	TES		North	South	
2	Price		0.2300	0.2300	
3	M3 User per year		2,342	2,237	
4	TES/ Yr		539	515	
5	Residential Use/Customer	2,300			
6	Comm Customer	10,000			
7	Comm Factor	4.3	<< use this to apply to above TES to apply for commerical loads		

Table 3 Customer Attachments

Line		% of Potential	North Attach	South attach	Total Attach
		(a)	(b)	(c)	(d)
1	Base Forecast @ 46.9%	46.9%	2,528	6,761	9,289
2	Percent by Area		27.2%	72.8%	100.0%
3	**Attachment Potential @ 100%**		5,390	14,415	19,805
4	Long Term Attach % of Potential	80%	4,312	11,532	15,844
5	Base Forecast @ 46.9%	46.9%	2,528	6,761	9,289
6	Additional Fcst Scenario	33.1%	1,784	4,771	6,555

Table 3 Cont'd: Calculate Residential vs Commerical Attachments at 80%

Line			Cust Potential	North Base Fcst	South Base Fcst	Total Base Fcst	80%	Incr Potential	North Incr	South Incr	Total North	Total South
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		Number of Customers	19,805	2,528	6,761	9,289	15,844	6,555	1,784	4,771	4,312	11,532
2	90%	Residential	17,825	2,275	6,085	8,360	14,260	5,900	1,606	4,294	3,881	10,379
3	10%	Commercial	1,981	253	676	929	1,584	656	178	477	431	1,153

Forecast Attachment Profile

Line			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	10 Year Forecast %	45.0%	27.0%	24.0%	9.0%	6.0%	5.0%	7.0%	5.0%	6.0%	6.0%	5.0%	-	-	-	-	-
2	Long Term Attach % of Potential	80%															
3	=Additional % Attachments	35%															
4	Num Yrs in base Fcst	10															
5	Add Years of Attach	15	<< Total years is 25														
6	Flag for Added Years	Flag	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1
7	Additonal % Per year	6.7%	-	-	-	-	-	-	-	-	-	-	6.7%	6.7%	6.7%	6.7%	6.7%

South Attachment by Year

Line		Yr>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
8	Base Attachment Profile	**South**	27%	24%	9%	6%	5%	7%	5%	6%	6%	5%	0%	0%	0%	0%	0%
9	Incr Attach Profile		-	-	-	-	-	-	-	-	-	-	6.7%	6.7%	6.7%	6.7%	6.7%
10	Residential adds: Base	6,085	1,643	1,460	548	365	304	426	304	365	365	304	-	-	-	-	-
11	Residential Incr Adds	4,294	-	-	-	-	-	-	-	-	-	-	286	286	286	286	286
12	Residential Adds Cummulative		1,643	3,103	3,651	4,016	4,320	4,746	5,050	5,416	5,781	6,085	6,371	6,657	6,944	7,230	7,516
13	Commercial Adds: Base	676	183	162	61	41	34	47	34	41	41	34	-	-	-	-	-
14	Commerical Incr Adds	477	-	-	-	-	-	-	-	-	-	-	32	32	32	32	32
15	Commercial Adds Cummulative		183	345	406	446	480	527	561	602	642	676	708	740	772	803	835
16	Total Cummulative	11,532	1,825	3,448	4,057	4,462	4,800	5,274	5,612	6,017	6,423	6,761	7,079	7,397	7,715	8,033	8,351

South Stage 2: Energy Cost Savings — Year by Year Figures in $ 000's

Line		**South**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Current Energy Cost (based on UGL Attachment Fcts)																
		$/ Year	$000's														
17	Residential	2,405	3,951	7,463	8,780	9,658	10,389	11,414	12,145	13,023	13,901	14,633	15,321	16,010	16,698	17,386	18,075
18	Commcerical	10,456	1,909	3,605	4,241	4,666	5,019	5,514	5,867	6,291	6,716	7,069	7,402	7,734	8,067	8,399	8,732
19	Total Current Energy Cost		5,859	11,068	13,021	14,323	15,408	16,927	18,013	19,315	20,617	21,702	22,723	23,744	24,765	25,786	26,807
	Conversion Cost	$/ Conversion	$000's														
20	Residential	4,068	6,683	5,941	2,228	1,485	1,238	1,733	1,238	1,485	1,485	1,238	1,164	1,164	1,164	1,164	1,164
21	Commerical	4,068	743	660	248	165	138	193	138	165	165	138	129	129	129	129	129
22	Total Conversion Cost		7,426	6,601	2,475	1,650	1,375	1,925	1,375	1,650	1,650	1,375	1,294	1,294	1,294	1,294	1,294
	Gas Cost																
		$/ Year	$000's														
23	Residential	759	1,246	2,354	2,769	3,046	3,277	3,600	3,831	4,108	4,385	4,616	4,833	5,050	5,267	5,484	5,701
24	Commerical	3,298	602	1,137	1,338	1,472	1,583	1,739	1,851	1,984	2,118	2,230	2,335	2,440	2,544	2,649	2,754
25	Total Gas Fuel Cost		1,848	3,491	4,107	4,518	4,860	5,339	5,682	6,092	6,503	6,845	7,167	7,489	7,812	8,134	8,456
	Fuel Savings Before TES	$/ Year	$000's														
26	Residential	1,646	2,705	5,109	6,010	6,611	7,112	7,813	8,314	8,915	9,516	10,017	10,488	10,960	11,431	11,902	12,373
27	Commerical	7,158	1,307	2,468	2,904	3,194	3,436	3,775	4,017	4,307	4,597	4,839	5,067	5,295	5,522	5,750	5,978
28	Total		4,011	7,577	8,914	9,805	10,548	11,588	12,331	13,222	14,114	14,856	15,555	16,254	16,953	17,652	18,351
29	**TES Forecast**	$ 000's	820	2,188	2,943	3,286	2,671	2,899	3,053	3,041	3,032	173	-	-	-	-	-

Line			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Summary	South	$000's														
30	Total Current Energy Cost		5,859	11,068	13,021	14,323	15,408	16,927	18,013	19,315	20,617	21,702	22,723	23,744	24,765	25,786	26,807
31	Less Total Conversion Cost		7,426	6,601	2,475	1,650	1,375	1,925	1,375	1,650	1,650	1,375	1,294	1,294	1,294	1,294	1,294
32	Less Total Gas Fuel Cost		1,848	3,491	4,107	4,518	4,860	5,339	5,682	6,092	6,503	6,845	7,167	7,489	7,812	8,134	8,456
33	Less TES Forecast		820	2,188	2,943	3,286	2,671	2,899	3,053	3,041	3,032	173	-	-	-	-	-
34	Net Energy Cost Savings		(4,235)	(1,212)	3,495	4,869	6,502	6,764	7,903	8,531	9,432	13,308	14,261	14,960	15,659	16,358	17,057

	Summary: Energy Savings $ 000's at Mkt share of 80.0%				
		South	Term	Term	Term
35	Discount Rate	5.00%	15	30	40
36	Discount Rate	10.00%			
37	NPV discounted at 5.0%		79,115	188,105	233,379
38	NPV discounted at 10.0%		48,814	87,628	96,551

Stage 2: Energy Cost Savings

		Yr>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
39	Base Attachment Profile	**North**	27%	24%	9%	6%	5%	7%	5%	6%	6%	5%	0%	0%	0%	0%	0%
40	Incr Attach Profile		-	-	-	-	-	-	-	-	-	-	6.7%	6.7%	6.7%	6.7%	6.7%
41	Residential adds: Base	2,275	614	546	205	137	114	159	114	137	137	114	-	-	-	-	-
42	Residential Incr Adds	1,606	-	-	-	-	-	-	-	-	-	-	107	107	107	107	107
43	Residential Adds Cummulative		614	1,160	1,365	1,502	1,615	1,775	1,888	2,025	2,161	2,275	2,382	2,489	2,596	2,703	2,810
44	Commercial Adds: Base	253	68	61	23	15	13	18	13	15	15	13	-	-	-	-	-
45	Commerical Incr Adds	178	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12
46	Commercial Adds Cummulative		68	129	152	167	179	197	210	225	240	253	265	277	288	300	312
47	Total Cummulative	4,312	683	1,289	1,517	1,668	1,795	1,972	2,098	2,250	2,402	2,528	2,647	2,766	2,885	3,004	3,123

Stage 2: Energy Cost Savings Year by Year Figures in $ 000's

		North	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Current Energy Cost (based on UGL Attachment Fcts)																
		$/ Year	$000's														
48	Residential	2,405	1,477	2,790	3,283	3,611	3,885	4,268	4,541	4,869	5,198	5,471	5,729	5,986	6,244	6,501	6,758
49	Commcerical	10,456	714	1,348	1,586	1,744	1,877	2,062	2,194	2,352	2,511	2,643	2,768	2,892	3,016	3,141	3,265
50	Total Current Energy Cost		2,191	4,138	4,869	5,356	5,761	6,329	6,735	7,222	7,709	8,115	8,496	8,878	9,260	9,641	10,023
	Conversion Cost	$/ Conversion	$000's														
51	Residential	4,068	2,499	2,221	833	555	463	648	463	555	555	463	435	435	435	435	435
52	Commerical	4,068	278	247	93	62	51	72	51	62	62	51	48	48	48	48	48
53	Total Conversion Cost		2,777	2,468	926	617	514	720	514	617	617	514	484	484	484	484	484
	Gas Cost (based on UGL Attachment Fcts)																
		$/ Year	$000's														
54	Residential	759	466	880	1,035	1,139	1,225	1,346	1,432	1,536	1,640	1,726	1,807	1,888	1,969	2,051	2,132
55	Commerical	3,298	225	425	500	550	592	650	692	742	792	834	873	912	951	991	1,030
56	Total Gas Fuel Cost		691	1,305	1,536	1,689	1,817	1,996	2,124	2,278	2,432	2,560	2,680	2,800	2,921	3,041	3,162
	Fuel Savings Before TES	$/ Year	$000's														
57	Residential	1,646	1,011	1,910	2,247	2,472	2,659	2,922	3,109	3,334	3,558	3,746	3,922	4,098	4,274	4,450	4,627
58	Commerical	7,158	489	923	1,086	1,194	1,285	1,411	1,502	1,610	1,719	1,809	1,895	1,980	2,065	2,150	2,235
59	Total		1,500	2,833	3,333	3,666	3,944	4,333	4,611	4,944	5,277	5,555	5,816	6,078	6,339	6,600	6,862

Line			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
60	**TES As Collected**	$ 000's	261	736	1,030	1,161	423	219	233	216	111	69	-	-	-	-	-
	Summary	**North**	$000's														
61	Total Current Energy Cost		2,191	4,138	4,869	5,356	5,761	6,329	6,735	7,222	7,709	8,115	8,496	8,878	9,260	9,641	10,023
62	Less Total Conversion Cost		2,777	2,468	926	617	514	720	514	617	617	514	484	484	484	484	484
63	Less Total Gas Fuel Cost		691	1,305	1,536	1,689	1,817	1,996	2,124	2,278	2,432	2,560	2,680	2,800	2,921	3,041	3,162
64	Less TES As Collected		261	736	1,030	1,161	423	219	233	216	111	69	-	-	-	-	-
65	Net Energy Cost Savings		(1,538)	(371)	1,377	1,888	3,006	3,394	3,863	4,111	4,549	4,972	5,333	5,594	5,855	6,117	6,378

	Summary: Energy Savings $ 000's at Mkt share of 80.0%				
		North	Term	Term	Term
66	Discount Rate	5.00%	15	30	40
67	Discount Rate	10.00%			
68	NPV discounted at 5.0%		32,838	73,590	90,518
69	NPV discounted at 10.0%		20,634	35,147	38,483

	Summary: Energy Savings $ 000's at Mkt share of 80.0%				
	Combined South & and North		Term	Term	Term
70	Discount Rate	5.00%	15	30	40
71	Discount Rate	10.00%			
72	NPV discounted at 5.0%		111,953	261,695	323,897
73	NPV discounted at 10.0%		69,447	122,775	135,035

Forecast Attachment Profile

Line			16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
1	10 Year Forecast %	45.0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Long Term Attach % of Potential	80%																
3	=Additional % Attachments	35%																
4	Num Yrs in base Fcst	10																
5	Add Years of Attach	15																
6	Flag for Added Years	Flag	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-
7	Additonal % Per year	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	-	-	-	-	-	-

South Attachment by Year

Line		Yr>	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
8	Base Attachment Profile	**South**	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	Incr Attach Profile		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	-	-	-	-	-	-
10	Residential adds: Base	6,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Residential Incr Adds	4,294	286	286	286	286	286	286	286	286	286	286	-	-	-	-	-	-
12	Residential Adds Cummulative		7,802	8,089	8,375	8,661	8,948	9,234	9,520	9,806	10,093	10,379	10,379	10,379	10,379	10,379	10,379	10,379
13	Commercial Adds: Base	676	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Commerical Incr Adds	477	32	32	32	32	32	32	32	32	32	32	-	-	-	-	-	-
15	Commercial Adds Cummulative		867	899	931	962	994	1,026	1,058	1,090	1,121	1,153	1,153	1,153	1,153	1,153	1,153	1,153
16	Total Cummulative	11,532	8,669	8,987	9,306	9,624	9,942	10,260	10,578	10,896	11,214	11,532	11,532	11,532	11,532	11,532	11,532	11,532

South Stage 2: Energy Cost Savings

Line		South	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Current Energy Cost (based on UGL Attachment Fcts)																	
		$/ Year																
17	Residential	2,405	18,763	19,452	20,140	20,828	21,517	22,205	22,894	23,582	24,270	24,959	24,959	24,959	24,959	24,959	24,959	24,959
18	Commcerical	10,456	9,064	9,397	9,729	10,062	10,395	10,727	11,060	11,392	11,725	12,057	12,057	12,057	12,057	12,057	12,057	12,057
19	Total Current Energy Cost		27,828	28,849	29,869	30,890	31,911	32,932	33,953	34,974	35,995	37,016	37,016	37,016	37,016	37,016	37,016	37,016
	Conversion Cost	$/ Conversion																
20	Residential	4,068	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	1,164	-	-	-	-	-	-
21	Commerical	4,068	129	129	129	129	129	129	129	129	129	129	-	-	-	-	-	-
22	Total Conversion Cost		1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	-	-	-	-	-	-
	Gas Cost																	
		$/ Year																
23	Residential	759	5,918	6,136	6,353	6,570	6,787	7,004	7,221	7,438	7,656	7,873	7,873	7,873	7,873	7,873	7,873	7,873
24	Commerical	3,298	2,859	2,964	3,069	3,174	3,279	3,384	3,489	3,593	3,698	3,803	3,803	3,803	3,803	3,803	3,803	3,803
25	Total Gas Fuel Cost		8,778	9,100	9,422	9,744	10,066	10,388	10,710	11,032	11,354	11,676	11,676	11,676	11,676	11,676	11,676	11,676
	Fuel Savings Before TES	$/ Year																
26	Residential	1,646	12,845	13,316	13,787	14,259	14,730	15,201	15,672	16,144	16,615	17,086	17,086	17,086	17,086	17,086	17,086	17,086
27	Commerical	7,158	6,205	6,433	6,661	6,888	7,116	7,343	7,571	7,799	8,026	8,254	8,254	8,254	8,254	8,254	8,254	8,254
28	Total		19,050	19,749	20,448	21,147	21,846	22,545	23,243	23,942	24,641	25,340	25,340	25,340	25,340	25,340	25,340	25,340
29	**TES Forecast**	$ 000's	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Line			16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Summary	South																
30	Total Current Energy Cost		27,828	28,849	29,869	30,890	31,911	32,932	33,953	34,974	35,995	37,016	37,016	37,016	37,016	37,016	37,016	37,016
31	Less Total Conversion Cost		1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	-	-	-	-	-	-
32	Less Total Gas Fuel Cost		8,778	9,100	9,422	9,744	10,066	10,388	10,710	11,032	11,354	11,676	11,676	11,676	11,676	11,676	11,676	11,676
33	Less TES Forecast		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Net Energy Cost Savings		17,756	18,455	19,154	19,853	20,552	21,251	21,950	22,649	23,347	24,046	25,340	25,340	25,340	25,340	25,340	25,340

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
		South
35	Discount Rate	5.00%
36	Discount Rate	10.00%
37	NPV discounted at 5.0%	
38	NPV discounted at 10.0%	

Stage 2: Energy Cost Savings

		Yr>	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
39	Base Attachment Profile	**North**	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
40	Incr Attach Profile		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	-	-	-	-	-	-
41	Residential adds: Base	2,275	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Residential Incr Adds	1,606	107	107	107	107	107	107	107	107	107	107	-	-	-	-	-	-
43	Residential Adds Cummulative		2,917	3,024	3,131	3,239	3,346	3,453	3,560	3,667	3,774	3,881	3,881	3,881	3,881	3,881	3,881	3,881
44	Commercial Adds: Base	253	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Commerical Incr Adds	178	12	12	12	12	12	12	12	12	12	12	-	-	-	-	-	-
46	Commercial Adds Cummulative		324	336	348	360	372	384	396	407	419	431	431	431	431	431	431	431
47	Total Cummulative	4,312	3,242	3,361	3,479	3,598	3,717	3,836	3,955	4,074	4,193	4,312	4,312	4,312	4,312	4,312	4,312	4,312

Stage 2: Energy Cost Savings

		North	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Current Energy Cost (based on UGL Attachment Fcts)																	
		$/ Year																
48	Residential	2,405	7,016	7,273	7,531	7,788	8,045	8,303	8,560	8,818	9,075	9,332	9,332	9,332	9,332	9,332	9,332	9,332
49	Commcerical	10,456	3,389	3,514	3,638	3,762	3,887	4,011	4,135	4,260	4,384	4,508	4,508	4,508	4,508	4,508	4,508	4,508
50	Total Current Energy Cost		10,405	10,787	11,168	11,550	11,932	12,314	12,695	13,077	13,459	13,841	13,841	13,841	13,841	13,841	13,841	13,841
	Conversion Cost	$/ Conversion																
51	Residential	4,068	435	435	435	435	435	435	435	435	435	435	-	-	-	-	-	-
52	Commerical	4,068	48	48	48	48	48	48	48	48	48	48	-	-	-	-	-	-
53	Total Conversion Cost		484	484	484	484	484	484	484	484	484	484	-	-	-	-	-	-
	Gas Cost (based on UGL Attachment Fcts)																	
		$/ Year																
54	Residential	759	2,213	2,294	2,375	2,457	2,538	2,619	2,700	2,781	2,862	2,944	2,944	2,944	2,944	2,944	2,944	2,944
55	Commerical	3,298	1,069	1,108	1,148	1,187	1,226	1,265	1,304	1,344	1,383	1,422	1,422	1,422	1,422	1,422	1,422	1,422
56	Total Gas Fuel Cost		3,282	3,402	3,523	3,643	3,764	3,884	4,005	4,125	4,245	4,366	4,366	4,366	4,366	4,366	4,366	4,366
	Fuel Savings Before TES	$/ Year																
57	Residential	1,646	4,803	4,979	5,155	5,331	5,508	5,684	5,860	6,036	6,212	6,389	6,389	6,389	6,389	6,389	6,389	6,389
58	Commerical	7,158	2,320	2,405	2,490	2,576	2,661	2,746	2,831	2,916	3,001	3,086	3,086	3,086	3,086	3,086	3,086	3,086
59	Total		7,123	7,384	7,646	7,907	8,168	8,430	8,691	8,952	9,214	9,475	9,475	9,475	9,475	9,475	9,475	9,475

Line			16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
60	**TES As Collected**	$ 000's	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Summary	**North**																
61	Total Current Energy Cost		10,405	10,787	11,168	11,550	11,932	12,314	12,695	13,077	13,459	13,841	13,841	13,841	13,841	13,841	13,841	13,841
62	Less Total Conversion Cost		484	484	484	484	484	484	484	484	484	484	-	-	-	-	-	-
63	Less Total Gas Fuel Cost		3,282	3,402	3,523	3,643	3,764	3,884	4,005	4,125	4,245	4,366	4,366	4,366	4,366	4,366	4,366	4,366
64	Less TES As Collected		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Net Energy Cost Savings		6,639	6,900	7,162	7,423	7,684	7,946	8,207	8,468	8,730	8,991	9,475	9,475	9,475	9,475	9,475	9,475

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
		North
66	Discount Rate	5.00%
67	Discount Rate	10.00%
68	NPV discounted at 5.0%	
69	NPV discounted at 10.0%	

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
	Combined South & and North	
70	Discount Rate	5.00%
71	Discount Rate	10.00%
72	NPV discounted at 5.0%	
73	NPV discounted at 10.0%	

Forecast Attachment Profile

Line			32	33	34	35	36	37	38	39	40
1	10 Year Forecast %	45.0%	-	-	-	-	-	-	-	-	-
2	Long Term Attach % of Potential	80%									
3	=Additional % Attachments	35%									
4	Num Yrs in base Fcst	10									
5	Add Years of Attach	15									
6	Flag for Added Years	Flag	-	-	-	-	-	-	-	-	-
7	Additonal % Per year	6.7%	-	-	-	-	-	-	-	-	-

South Attachment by Year

		Yr>	32	33	34	35	36	37	38	39	40
8	Base Attachment Profile	**South**	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	Incr Attach Profile		-	-	-	-	-	-	-	-	-
10	Residential adds: Base	6,085	-	-	-	-	-	-	-	-	-
11	Residential Incr Adds	4,294	-	-	-	-	-	-	-	-	-
12	Residential Adds Cummulative		10,379	10,379	10,379	10,379	10,379	10,379	10,379	10,379	10,379
13	Commercial Adds: Base	676	-	-	-	-	-	-	-	-	-
14	Commerical Incr Adds	477	-	-	-	-	-	-	-	-	-
15	Commercial Adds Cummulative		1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
16	Total Cummulative	11,532	11,532	11,532	11,532	11,532	11,532	11,532	11,532	11,532	11,532

South Stage 2: Energy Cost Savings

		South	32	33	34	35	36	37	38	39	40
	Current Energy Cost (based on UGL Attachment Fcts)										
		$/ Year									
17	Residential	2,405	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959	24,959
18	Commcerical	10,456	12,057	12,057	12,057	12,057	12,057	12,057	12,057	12,057	12,057
19	Total Current Energy Cost		37,016	37,016	37,016	37,016	37,016	37,016	37,016	37,016	37,016
	Conversion Cost	$/ Conversion									
20	Residential	4,068	-	-	-	-	-	-	-	-	-
21	Commerical	4,068	-	-	-	-	-	-	-	-	-
22	Total Conversion Cost		-	-	-	-	-	-	-	-	-
	Gas Cost										
		$/ Year									
23	Residential	759	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873
24	Commerical	3,298	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803	3,803
25	Total Gas Fuel Cost		11,676	11,676	11,676	11,676	11,676	11,676	11,676	11,676	11,676
	Fuel Savings Before TES	$/ Year									
26	Residential	1,646	17,086	17,086	17,086	17,086	17,086	17,086	17,086	17,086	17,086
27	Commerical	7,158	8,254	8,254	8,254	8,254	8,254	8,254	8,254	8,254	8,254
28	Total		25,340	25,340	25,340	25,340	25,340	25,340	25,340	25,340	25,340
29	**TES Forecast**	$ 000's	-	-	-	-	-	-	-	-	-

Line			32	33	34	35	36	37	38	39	40
	Summary	South									
30	Total Current Energy Cost		37,016	37,016	37,016	37,016	37,016	37,016	37,016	37,016	37,016
31	Less Total Conversion Cost		-	-	-	-	-	-	-	-	-
32	Less Total Gas Fuel Cost		11,676	11,676	11,676	11,676	11,676	11,676	11,676	11,676	11,676
33	Less TES Forecast		-	-	-	-	-	-	-	-	-
34	Net Energy Cost Savings		25,340	25,340	25,340	25,340	25,340	25,340	25,340	25,340	25,340

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
		South
35	Discount Rate	5.00%
36	Discount Rate	10.00%
37	NPV discounted at 5.0%	
38	NPV discounted at 10.0%	

Stage 2: Energy Cost Savings

		Yr>	32	33	34	35	36	37	38	39	40
39	Base Attachment Profile	**North**	0%	0%	0%	0%	0%	0%	0%	0%	0%
40	Incr Attach Profile		-	-	-	-	-	-	-	-	-
41	Residential adds: Base	2,275	-	-	-	-	-	-	-	-	-
42	Residential Incr Adds	1,606	-	-	-	-	-	-	-	-	-
43	Residential Adds Cummulative		3,881	3,881	3,881	3,881	3,881	3,881	3,881	3,881	3,881
44	Commercial Adds: Base	253	-	-	-	-	-	-	-	-	-
45	Commerical Incr Adds	178	-	-	-	-	-	-	-	-	-
46	Commercial Adds Cummulative		431	431	431	431	431	431	431	431	431
47	Total Cummulative	4,312	4,312	4,312	4,312	4,312	4,312	4,312	4,312	4,312	4,312

Stage 2: Energy Cost Savings

		North	32	33	34	35	36	37	38	39	40
	Current Energy Cost (based on UGL Attachment Fcts)										
		$/ Year									
48	Residential	2,405	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332
49	Commcerical	10,456	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508	4,508
50	Total Current Energy Cost		13,841	13,841	13,841	13,841	13,841	13,841	13,841	13,841	13,841
	Conversion Cost	$/ Conversion									
51	Residential	4,068	-	-	-	-	-	-	-	-	-
52	Commerical	4,068	-	-	-	-	-	-	-	-	-
53	Total Conversion Cost		-	-	-	-	-	-	-	-	-
	Gas Cost (based on UGL Attachment Fcts)										
		$/ Year									
54	Residential	759	2,944	2,944	2,944	2,944	2,944	2,944	2,944	2,944	2,944
55	Commerical	3,298	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422	1,422
56	Total Gas Fuel Cost		4,366	4,366	4,366	4,366	4,366	4,366	4,366	4,366	4,366
	Fuel Savings Before TES	$/ Year									
57	Residential	1,646	6,389	6,389	6,389	6,389	6,389	6,389	6,389	6,389	6,389
58	Commerical	7,158	3,086	3,086	3,086	3,086	3,086	3,086	3,086	3,086	3,086
59	Total		9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475

Line			32	33	34	35	36	37	38	39	40
60	**TES As Collected**	$ 000's	-	-	-	-	-	-	-	-	-
	Summary	**North**									
61	Total Current Energy Cost		13,841	13,841	13,841	13,841	13,841	13,841	13,841	13,841	13,841
62	Less Total Conversion Cost		-	-	-	-	-	-	-	-	-
63	Less Total Gas Fuel Cost		4,366	4,366	4,366	4,366	4,366	4,366	4,366	4,366	4,366
64	Less TES As Collected		-	-	-	-	-	-	-	-	-
65	Net Energy Cost Savings		9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475	9,475

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
		North
66	Discount Rate	5.00%
67	Discount Rate	10.00%
68	NPV discounted at 5.0%	
69	NPV discounted at 10.0%	

	Summary: Energy Savings $ 000's at Mkt share of 80.0%	
	Combined South & and North	
70	Discount Rate	5.00%
71	Discount Rate	10.00%
72	NPV discounted at 5.0%	
73	NPV discounted at 10.0%	

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 38, lines 16-18 and p. 39, lines 4-5

Union states that potential customers could save between $248 million and $324 million if they had access to natural gas. Union further states that the total capital investment to provide natural gas is $150 million. Accordingly, even if new customers paid the full cost of obtaining natural gas service, they would have net savings of approximately $98 million to $174 million.

a) Why does Union oppose requiring new customers to pay the entire cost of obtaining natural gas, which according to Union's own figures, would still leave them with a net savings of over $98 million, as opposed to only requiring them to pay some of the costs and requiring existing users to subsidize the remainder?

b) Please advise whether Union surveyed potential customers regarding whether they would choose to connect if they had to pay their full share of the capital costs? If so, provide a copy of the survey and the full survey results.

Response:

a) New communities have been, and are currently, unable to pay the full share of the capital costs. Had they been willing to do so, Union would have already expanded its natural gas system to serve them under E.B.O. 188, and the current proposal would not be required.

b) Union did not survey potential customers to determine if they would pay a full share of the capital costs. Union is aware of a handful of residential customers who were willing to pay Aid-to-Construction of approximately $2,000 over the past couple of years. However, Union has not experienced any residential customers who were willing to pay Aid-to-Construction ranging from $5,000 to $20,000, which would be required for these projects, as can be seen in Exhibit A, Tab 1, Figure 4.

   Union is aware that a customer's interest in converting to natural gas varies with the cost. Union tested this concept with the third party phone market surveys for Milverton, Lambton Shores, and Prince Township[1]. With these surveys, Union asked about interest in converting in the absence of a TES, and with a TES of $450 per year for up to 10 years. The results were a reduced likelihood to convert, with on average, between 78% and 90% of those who expressed likelihood to convert without a TES, still expressing a likelihood to convert with the TES. If the TES was set high enough to allow the projects to reach a P.I. of 1.0, the

[1] Exhibit B.CPA.1 a) x), xi), and xiii).

further reduction in customer interest could be dramatic and very few customers would be likely to convert. Please also see the response at Exhibit B.CCC.7.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 40, lines 16-20 and p. 41, lines 18-21

To calculate rate impacts, Union included the forecasted contributions associated with TES and ITE contributions. Accordingly, if Union's forecasted contributions are incorrect, current customers (and not Union shareholders) will pay increased rates beyond the rate impacts projected by Union in the Application.

a) What principle justifies requiring current customers (and not Union shareholders or new customers) to be exclusively responsible for any shortfall?

b) How is this principle consistent with the principle set out by the OEB in section 6.1.3 of E.B.O 188 that utility shareholders should bear the risk of forecasting errors?

Response:

a) Please see the response at Exhibit B.CPA.16 a).

b) Please see the response at Exhibit B.CPA.11 c).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 43, lines 1-3

Union states that "any potential Natural Gas Access Loans and Natural Gas Economic Development Grants received in advance of project construction will be treated as an aid-to-construction and reduce the gross project capital."

a) Advise whether the Natural Gas Access Loans and Natural Gas Economic Development Grants will accrue solely to the benefit of current ratepayers, and not to reduce the TES, TCS or ITE or their transition periods.

Response:

a) While Union does not know the details of the Natural Gas Access Loans or Natural Gas Economic Development Grants, under Union's proposal an Aid-to-Construction ("CIAC") is only required after both the TES and ITE have been applied for the maximum proposed 10 years.

   To the extent that a community can provide an up-front CIAC payment regardless of the source of the funding, it would first serve to reduce any CIAC required, and any residual amounts would be used to reduce the term of the TES and ITE.

   As noted in the response at Exhibit B.CCC.16, Union's understanding is that Community Expansion Projects would need to exhaust any available regulatory flexibility before they would become eligible for provincial funding.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, p. 44, lines 15-17
Exhibit A, Tab 1, p. 45, Table 8, Table 5
Schedule 2 to each Leave to Construct Application

Union bases its Application on attachment forecasts which it claims are based in part on phone surveys and community leader discussions. Union has not provided any survey questions, copies of surveys, actual data arising from the surveys, any description of those targeted for surveys, any description of those who responded to surveys, or response rates. Nor has any supporting information been provided regarding the scope or content of their discussions.

a) Provide all survey questions, copies of surveys, actual data arising from the surveys, demographic descriptions of survey respondents, descriptions of those called, survey response rates, discussion notes and engagement logs related to the discussions cited by Union, and any other evidence and background information to support the purported attachment forecast conclusions reached by Union and relied upon in the Application, including the five Leave to Construct Applications; all to the extent that such information is not already provided in response to CPA Question No. 1.

Response:

a) Please see the response at Exhibit B.Staff.11.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, Appendix D, Col. 4

The "potential customer" figures cited by Union appear to differ from the customer populations of the relevant communities. Union has not provided any description or explanation of how it identified or determined potential customers.

a) Explain how Union identified and determined "potential customers" for each project.

Response:

a) A number of different methods were used to determine potential customers in each municipality. They included discussions with municipal officials, field surveys where houses were counted, counting the number of roofs from large scale aerial photography and population counts assuming an average 2.56 occupants per household. For purposes of this Application, an installed meter would be representative of a customer.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, Appendix H, p. 4, lines 5-6

Union's proposed Guidelines require PI to be equal to or greater than 0.4 "including any customer and municipal contributions". Projects could, therefore, meet the proposed guidelines with a PI of almost nil and Union could simply charge TES and ICT in order to bring it up to 0.4.

a) What is the basis for eliminating the PI requirement, instead of requiring a starting PI of 0.4 before applying the TES of ICT (which could be used to bring the PI up to 0.8 or higher)?

Response:

a) Union has structured its proposal to meet the government's desire to complete the maximum number of Projects, and Union has applied its experience, judgment and regulatory precedent to also include a maximum ratepayer impact. Applying the above criteria to the natural P.I.'s of the Projects Union identified in Exhibit A, Tab 1, Appendix D, would result in the elimination of all but two of the 103 Projects. If Union were to adopt this approach, Union's proposal would not address the government's goals as identified in the Long Term Energy Plan, or the letter from the Ministry to the Board[1].

[1] Exhibit A, Tab 1, Appendix A, p. 1.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, Appendix J, line 12, and Note (6)

The revenues added at Line 12 of the table are said to be "incremental revenues associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer."

a) Provide the data and formulas used to calculate, and the calculations for, the estimated Incremental Revenue for the 30 projects.

Response:

a) Please see the response at Exhibit B.LPMA.24 b).

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: Exhibit A, Tab 1, Appendix K

Union has capped the TES at $0.23 per m^3, which is based on its attachment forecast. However, if the attachment forecast is wrong, then TES revenue will be higher or lower, and therefore the rate increase for current customers (e.g. M1, M2) will not be as set out.

a) Provide a range of attachment scenarios (percentage and timing) and the corresponding range of rate impacts, with appropriate explanations and supporting data.

Response:

The attachment forecasts were not a determinant in setting the TES Rate.

a) Union has provided estimated impacts for a range of attachment rates and annual volumes in the response at Exhibit B.South Bruce.6. Union has not reproduced Exhibit A, Tab 1, Appendix K for "a range of attachment scenarios" due to the number of unspecified variable values in the request. In order to do so, for each variable value change, 30 economic models would need to be created and the resulting rate impacts determined. This effort would require an unreasonable level of effort, given the intent of the Opportunity Assessment as noted in the response at Exhibit B.SEC.15, and the estimated rate impacts that were derived from that Assessment.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Propane Association ("CPA")

Reference: KPMG Report "Jurisdictional Review of Natural Gas Distribution System Expansions" posted by OEB on March 31, 2015 in EB-2015-0156

According to the KPMG Report filed by the OEB as part of its Natural Gas Expansion Policy Consultation, in New Brunswick, Enbridge forecasted 70,000 attachments in 23 communities. Fifteen years later, it has 12,000 customers in 10 communities; its attachment forecasts were off by 83%. In Maine, SNG forecasted that it would serve 15,000 customers, but it serves only 3,000; its attachment forecasts were off by 80%.

a) Why does Union believe its forecasting ability is at least 80% more accurate than Enbridge's and SNG's?

Response:

a) Union is not aware of the market conditions, how the forecasts were derived, the relative savings by converting, or the types of marketing efforts undertaken in either Maine or New Brunswick. However, in both cases it appears new entrants (gas distributors) in the State or Province were chosen to develop the systems.

   In contrast, Union has operated gas distribution systems in Ontario for over 100 years and has a proven track record. Throughout this time, Union has expanded from a start-up to the point where it now provides service to over 1.4 million customers in 400 communities. Each of these communities at some point represented a Community Expansion opportunity. The response at Exhibit B.SEC.22 demonstrates Union's success in making Community Expansion Projects successful.

   For the most recent Community Expansion Project, Red Lake, in the four years following construction in 2012, Union connected 73% (919 of 1,265) of the private dwellings identified at the time the forecast was developed for that project.

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 12

Preamble: Beginning at Line 8 of the reference, Union discusses the economic benefits of expanding its distribution system to unserved communities. Enbridge wishes to understand the extent to which Union is aware of reports or studies that examine the impacts of expanding natural gas service to unserved communities.

Is Union aware of any reports or studies which address the impacts of expansion of natural gas distribution service to currently unserved communities in Canada or in other jurisdictions? If yes please provide these studies and / or reports.

Response:

Please see the response at Exhibit B.CCC.5.

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 45, Table 8

Preamble: Enbridge would like to gain a better understanding of the assumptions used by Union to perform the feasibility analysis for each of the communities identified in Table 8.

Please provide Union's assumed customer capture rates by year for each of the leave to construct projects identified in Table 8. How do these assumed customer capture rates compare to actual customer capture rates experienced in Union's franchise area for other similar projects that have been completed?

Response:

The forecasted capture rates are provided at Exhibit A, Tab 2 schedules for each of the proposed projects.

Please see the response at Exhibit B.Staff.12 a) for the similar projects, which are the basis of forecasted attachments for the proposed projects.

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 20

Preamble: At Line 15 of the reference Union discusses the term of the TES. Enbridge wishes to understand the rationale for selection of the term of the TES.

Why is the term of the TES set at a maximum of 10 years? Please explain the rationale behind setting this particular term for the TES.

Response:

The maximum of 10 years is based on Union's judgment, taking several factors into account, including:

- A period longer than 10 years would improve Project P.I.'s but the degree of improvement would be muted by the time value of money. Given a discount rate of 5.1%[1], the $500 per year in TES in current dollars is equivalent to $320, $249, and $194 in years 10, 15, and 20 respectively.

- A longer timeframe might lead to fewer forecasted attachments.

- The 10 year timeframe is based on a subjective assessment of the probability of at least the current competitive cost advantage of natural gas relative to other fuels being maintained. Extending this period would benefit Project economics, but may raise some level of concern that the comparative value proposition might change over the longer term.

- A longer period would require extending the period for which tracking and reporting mechanisms would need to apply.

Union tested a term of as long as 10 years in the surveys[2] for Milverton, Prince Township and Lambton Shores, and found that 90% of potential customers who were likely to convert in absence of the TES would still do so with the TES.

Union also considered setting a rolling term that begins when each customer connects to a Project as opposed to when the Project is put into service. Union modelled the most extreme case where a 10 year TES term is a rolling 10 year term from year of attachment (e.g. TES for

[1] Incremental weighted after-tax average cost of capital, as used for the projects in Exhibit A, Tab 2.

[2] Survey details can be found at Exhibit B.Staff.11.

the last connection in year 10 continues to year 20). The improvement in the P.I. is immaterial at less than 0.02. A significant down side to this approach would be the need to track and administer the TES deferral process for a period that could approach 20 years.

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 22

Preamble: Beginning at Line 3 of the reference Union discusses its proposed ITE. Enbridge wishes to better understand the ITE.

Please explain why the municipality could not simply forgo the collection of municipal taxes on company plant located in community expansion projects as opposed to Union's ITE proposal.

Response:

Municipalities in Ontario are governed by the Municipal Act. It is Union's understanding that per Section 106 of the Municipal Act, Municipalities are not legally permitted to give a total or partial exemption from any levy, charge or fee, directly or indirectly, to a commercial enterprise.

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 13

Preamble: Beginning at Line 7 of the reference Union indicates that it has been approached by several municipal and provincial representatives to explore ways to expand natural gas infrastructure to additional remote communities.

Please provide a list of all municipalities that have inquired with Union with respect to the extension of gas service to their communities within the past three years.

Response:

Union does not have a list of every contact initiated by municipalities over a three year period because all the contacts are not documented. The inquiries have occurred in a broad range of venues and settings, ranging from a telephone request, contact at a municipal or other type of conference or at a social event, or a formal presentation request. Records of dates and contacts are not readily available.

However, Union can confirm that it has had contact with municipalities specific to all but one of the first 30 Projects identified in Exhibit A, Tab 1, Appendix D, within the past two years. In total, Union can confirm that potential customers or elected representatives from at least 65 of the Project areas have inquired about obtaining natural gas service, as shown in Attachment 1. The row numbers in Attachment 1 correspond to the row numbers in Exhibit A, Tab 1, Appendix D.

Union has received inquiries from several other areas since this Application was submitted. Such inquiries include Mallorytown, Holstein/Ayton, and Minden Hills.

Prior Inquiries

Row	Community Name	Past Inquiries
1	Milverton	Past Inquiries - not economically feasible in past
2	Prince Township, Sault Ste Marie	Past Inquiries - not economically feasible in past
3	Lambton Shores, Kettle Point First Nation	Past Inquiries - not economically feasible in past
4	Walpole Island First Nation- main commercial area	Currently In progress
5	Moraviantown First Nation- main commercial area	Past Inquiries - not economically feasible in past
6	Lagoon City (Orillia)	Past Inquiries - not economically feasible in past
7	Hidden Valley/Huntsville	Partial Expansion in 2013
8	Santa's Village/Bracebridge	Past Inquiries - not economically feasible in past
9	Canal Road (Gravenhurst)	Past Inquiries - not economically feasible in past
10	Northshore Rd / Peninsula Rd North Bay	Past Inquiries - not economically feasible in past
11	Hornby	Past Inquiries - not economically feasible in past
12	Oneida First Nation	Conversations with past chiefs - no pricing provided
13	Auburn	Met at ROMA - no pricing
14	Cedar Springs	Past Inquiries - not economically feasible in past
15	Astorville	Past Inquiries - not economically feasible in past
16	***Brenman Line, Servern Twp (Gravenhurst)	No Inquiries prior to 2015
17	Nipissing First Nation / Jocko Point	Estimate in 2013/2014 for Federal funding application
18	***Munsee Delaware First Nation	Past inquiries - in 2015.
19	Chippewa of the Thames First Nation- phase 3 & 4	Past Inquiries - not economically feasible in past
20	Sheffield	No Inquiries prior to 2015
21	Turkey Point	Past Inquiries - not economically feasible in past
22	Rockton	No Inquiries prior to 2015
23	Chippewas of the Saugeen	Past Inquiries (2015) - not economically feasible in past
24	Washago	Past Inquiries >10 years
25	E Floral (T Bay area)	Past Inquiries - not economically feasible in past
26	Haldimand Shores	Past Inquiries - not economically feasible in past
27	Latchford, Tri Town	Past Inquiries - not economically feasible in past
28	Belwood	UG contacted Belwood
29	Kincardine. Tiverton, Paisley, Chesley	Past Inquiries - not economically feasible in past
30	***Little Longlac	Identified as part of 2014 Project
31	Swiss Meadow	No Inquiries prior to 2015
32	Boblo Island	Past Inquiries - not economically feasible in past
33	Village of Warwick	Past Inquiries - not economically feasible in past
34	Mohawks of the Bay of Quinte (Tyendinaga FN)	Currently In progress
37	Wroxieter/Gorrie/Fordwich	Past Inquiries - not economically feasible in past
39	Long Lake Phase 3, Sudbury	Past Inquiries - not economically feasible in past
41	***Emsdale Muskoka	Past Inquiries - not economically feasible in past
42	Consecon- Ameliasburgh, Rossmore	Past Inquiries – not economically feasible in past
43	Keast and South Bay Rd, Sudbury	Past Inquiries - not economically feasible in past
44	Neustadt	Past Inquiries > 10 years, not feasible
47	St Charles, Sudbury	Past Inquiries - not economically feasible in past
48	Spencerville	Past Inquiries - not economically feasible in past
51	Nobel (Parry Sound)	Past Inquiries - not economically feasible in past
53	Chukuni Subdivision (Red Lake area)	Proposed to be completed in 2016
54	Ripley,Lucknow	Past Inquiries - not economically feasible in past
57	Gillies (outside Thunder Bay)	Past Inquiries - not economically feasible in past
61	Webbwood and McKerrow + Massey	Past Inquiries - not economically feasible in past
62	Centenial Cres, North Bay	No recent work
64	Charlton NW of Englehart	Past Inquiries - not economically feasible in past

Prior Inquiries

Row	Community Name	Past Inquiries
69	Sioux Lookout, Hudson, Lac Seul FN, Fisherman's Head	Past Inquiries - not economically feasible in past
72	Back Rd- Timmins area	Partially served in 2015
74	Field	Past Inquiries - not economically feasible in past
75	Slate River (outside Thunder Bay)	Past Inquiries - not economically feasible in past
76	Hagar	2014 Inquiry
77	Rosseau (Parry Sound)	Past Inquiries - not economically feasible in past
80	Town of Wabigoon, Wabigoon First Nation	Past Inquiries - not economically feasible in past
81	O'Connor (Outside Thunder Bay)	Past Inquiries - not economically feasible in past
82	Terrace Bay, Schrieber, Marathon	Past Inquiries - not economically feasible in past
83	Conmee (outside Thunder Bay)	Past Inquiries - not economically feasible in past
84	Algoma Mills, Spragge, Serpent River, Spanish	Past Inquiries - not economically feasible in past
86	Nolalu (outside Thunder Bay)	Past Inquiries - not economically feasible in past
87	***Dorion (outside Thunder Bay)	Past Inquiries - not economically feasible in past
88	***Marks Township (outside Thunder Bay)	Past Inquiries - not economically feasible in past
90	Kaministiquia	Past Inquiries - not economically feasible in past
101	***Baysville Muskoka	Past Inquiries > 10 years

UNION GAS LIMITED

Answer to Interrogatory from
Enbridge Gas Distribution Inc. ("EGD")

Reference: Exhibit A, Tab 1, p. 17

Preamble: Beginning at Line 9 of the reference, Union indicates that the proposed TES will apply to only potential general service customers attaching to systems installed as part of a community expansion project. Enbridge would like to understand why the TES will be applied to general service customers only.

a) Why does Union propose not to have the TES apply to contract customers when, in the event of a community expansion, these customers, like general service customers, will also benefit from community expansion?

b) Would Union consider applying the TES to all customers (general service and contract customers) residing in a community expansion project? If not, why not?

Response:

a) Union identified fewer than five potential contract[1] customers in the 30 Projects that might become feasible under its proposal. Union considered developing a TES for contract customers, and informally consulted with the largest potential contract customer identified to determine what type of rate would be competitive. It became clear through those discussions that a rate of $0.23/m^3 would not lead to a decision to attach to the system.

   Union recognizes that because of the large volumes of energy consumed, landed costs of natural gas as well as competing forms of energy are significantly lower per unit delivered for contract customers than for general service customers. If a TES was proposed for these customers a unique rate would be required for each contract rate class.

   Recognizing the limited number of contract customers in expansion communities that a TES would apply to, Union has proposed an alternative approach[2] for these customers that will allow them to support expansion projects to serve their communities and to gain the economic benefits should they make a decision to attach to the system. Please see the response at Exhibit B.LPMA.2 a) for further details.

b) Please see part a) above.

[1] Potential contract customers have expected annual volumes in excess of 350,000 m^3 per year.
[2] Exhibit A, Tab 1, p. 26, line 13.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation (“Energy Probe”)

Reference: Exhibit A, Tab 1, Appendix A- OEB Letter February 18, 2015

a) Please provide a list of all correspondence, e-mails and notes or minutes of meetings with Government Ministry officials and with Ontario Energy Board Staff in the development of the Application. Indicate the availability of the listed documents.

b) Please provide a list of correspondence, e-mails and notes or minutes of meetings with the 5 proposed communities in development of the Application. Indicate the availability of the listed documents.

c) Please provide Union’s costs related to the Opportunity Assessment Project.

d) Please provide Union’s costs related to the development of the Application and of the 5 Community Expansion Project LTC applications.

e) Please explain how Union proposes to recover these costs if the applications are/are not approved.

Response:

a) Union has discussed its intent to develop a Community Expansion proposal with Government Ministry officials as well as Board staff on a number of occasions. Attachment 1 provides a list of these contacts.

b) Please see the response at Exhibit B.SEC.16.

c) Union did not track the cost of developing the information in the Opportunity Assessment.

d) The costs related to the development of the Application and the five Community Expansion Project applications are being managed within Union’s existing O&M Budget.[1] Project specific expenses include the Environmental Report and Archaeological Assessment costs of $165,000 and Customer Survey costs of $24,000.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union’s Community Expansion proposals to make it economically feasible.

e) The costs to develop this Application will be managed within the price cap of Union's existing IRM framework.

Provncial Government Meeting/Correspondence Summary

Date	Party	Document Description	Documents Available
2015/11/17	Economic Development, Ministry of Energy, OMAFRA	Presentation - Community Expansion	Yes
2015/05/12	Ministry of Energy	Presentation - Community Expansion	Yes
2015/04/08	OEB/Stakeholders	Presentation - Community Expansion	Yes
2015/03/25	Economic Development	Email - followup response with communities and estimated costs	Yes
2015/01/07	Ministry of Energy	Correspondence - cost impacts	Yes
2014/12/16	Economic Development Minister	Presentation - Community Expansion	Yes
2014/11/27	OEB Staff	Presentation - Community Expansion	Yes
2014/11/27	Ministry of Energy, Economic Development	Presentation - Community Expansion	Yes
2014/11/14	Economic Development, Ministry of Energy	Email - followup response with community expansion process	Yes
2014/11/12	Ministry of Energy	Email - followup response with equipment conversion costs	Yes
2014/10/30	Ministry of Energy	Email - followup response with P.I. and rolling portfolio descriptions	Yes
2014/10/29	Various	Community Expansion Outline and Natural Gas presentations	Yes
2014/10/10	Ministry of Energy	Email - followup response with explanation of P.I.'s	Yes
2014/10/09	Ministry of Energy	Email - scheduling meeting	Yes
2014/04/17	OMAFRA	Email - meeting summary	No
2014/04/09	OEB/Stakeholders	Presentation - Community Expansion	Yes
2014/03/24	OMAFRA, OFA	Presentation - Community Expansion	Yes
2014/02/27	Ministry of Energy	Correspondence - responses to follow up questions	Yes
2014/02/12	Ministry of Energy	Correspondence - Potential Project List	Yes
2014/01/20	Ministry of Energy	Community Expansion Program Options	Yes

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 1

Preamble: The Ontario government's desire to expand natural gas distribution systems, which will increase natural gas use, is inconsistent with their recently announced intent to implement a cap and trade program whose objective is to significantly reduce the use of natural gas. While Union supports its Community Expansion proposals as filed in this application, the ultimate degree to which any approved regulatory flexibility is used will depend on reconciling these two opposing government policy positions.

Please provide any correspondence (emails, letters and so on) that it has been written to or received from the provincial government regarding the provincial government's proposed cap and trade system for carbon emissions.

Response:

Attachment 1 reflects Union's position on cap and trade, including community expansion and that it has no other correspondence related to cap and trade in the context of community expansion.

November 25, 2015

Melissa Ollevier, Senior Policy Advisor
Ministry of the Environment and Climate Change
Climate Change and Environmental Policy Division
Air Policy Instruments and Programs Design Branch
77 Wellesley Street West, Floor 10, Ferguson Block
Toronto, Ontario
M7A 2T5

Re: Initial Submissions of Union Gas Limited regarding the Greenhouse Gas ("GHG") Cap-and-Trade System being developed by the Ontario Ministry of the Environment and Climate Change ("MOECC")

Union Gas has received the MOECC's November 2015 Cap & Trade Program Design Options presentation, and Union will be submitting a separate document by the December 15, 2015 deadline responding to the questions identified in the presentation.

At this time, Union Gas is pleased to submit these initial comments regarding the province's anticipated GHG cap-and-trade system. As a large natural gas distribution company serving over 1.4 million customers across Ontario, and a large covered emitter itself, Union Gas has a constructive role to play in helping the government develop a Made-in-Ontario Cap & Trade framework that will realize the shared goals of reducing Ontario greenhouse gas emissions while ensuring the competitiveness of Ontario businesses is not harmed. Union Gas has developed models to better understand the impacts of cap and trade on the natural gas sector in the province and to help identify opportunities to reduce emissions in a cost-effective manner. We have investigated opportunities that would enable tangible emissions reductions here in Ontario, balanced against the needs of industry for cost-competitive energy; and we examined the general financial burden that could be placed on families and small businesses. Based on this analysis, Union Gas recommends that the following three themes guide the government's development of the Cap & Trade Framework:

- Theme #1: Phase-in the Consumer Impact
- Theme #2: Be Transparent
- Theme #3: Use Auction Proceeds for Cost-Effective Abatement

These themes are explained briefly below.

Theme #1: Phase-in the Consumer Impact

Four important considerations drive our recommendation to phase-in the impact on consumers.

1) ***The need to develop the regulatory framework for natural gas utilities***

Union Gas recommends starting the Cap & Trade framework with transportation fuels in 2017, and **adding the natural gas sector on January 1, 2018**. This solution enables Ontario to meet its objective of launching the framework on January 1, 2017 with the much less complex transportation fuels sector, and will provide the Ontario Energy Board with sufficient time to conduct a transparent process for the development and implementation of the corresponding regulatory framework necessary for gas distributors to participate in the Cap & Trade system. While Ontario's situation is unique from other jurisdictions, delayed introduction of the natural gas sector is consistent with the approach taken by both California and Quebec.

2) ***The need to manage abnormal cost impacts on Ontario energy consumers***

Union Gas recommends following the California model of allowance allocation which provide a very high percentage of required allowances to natural gas distributors free of charge, and requires distributors to auction off a percentage of those allowances gradually over time. The funds raised through the sale of allocated allowances would be used for the benefit of customers. The allocation of free allowances to natural gas distributors is a key design feature of the cap-and-trade system in California and was done expressly to ease the bill impact for consumers and businesses. **The case for free allowances is even stronger in Ontario than in California (**home heating is 59 per cent in California and 76 per cent in Ontario, with much colder climate).

Energy consumers in Ontario are already experiencing significant electricity price increases. In California, concern for the impact on natural gas consumers led state authorities to mitigate the impact on natural gas consumers by providing natural gas distributors with free allowances, coupled with an obligation on the distributors to sell an increasing percentage of those allowances and to use the proceeds for the benefit of customers. Our modelling indicates that the **average Ontario residential consumer could be paying over $1,200 more per year in cumulative energy bills by 2025 [natural gas ($475/year), gasoline ($400/year) and electricity ($380/year)]. A representative small auto parts manufacturer could see a cumulative increase to natural gas and electricity costs of over $1 million per year by 2025.** A phased-in approach will allow time for customer education, enable consumers to make adjustments to their behavior, and thereby build broader understanding and support for the cap-and-trade approach

3) ***Equity and Fairness***

The allocation of free allowances to natural gas distributors also addresses the issues relating to equity and fairness. It is our understanding that Ontario intends to provide large final emitters with up to 100 percent free allowances through 2020 (subject to annual reductions in the cap). As a result, the vast majority of auction revenues being considered during that time period will be derived from small- and medium-sized businesses, electricity consumers (as a result of costs passed on by natural gas-fired electricity generators) and Ontario residents (in addition to those who consume electricity, homeowners who use natural gas to heat their homes and those who drive automobiles). **Providing natural gas distributors with free allowances reduces the costs faced by those smaller businesses and households and mitigates the perception of unfairness**

4) ***Addressing competitive trade issues***

An allocation of free allowances also helps to address the concern that small- and medium-sized businesses constitute an important component of the Ontario economy yet will be incurring new costs that their competitors in neighbouring states will not. Providing natural gas distributors with free allowances at first, with a steady reduction over a number of years, **constitutes a simple means of mitigating the unintended consequence of the possible adverse trade and competitive impacts** that such small- and medium-sized businesses may suffer under the cap-and-trade system.

Theme #2 – Be Transparent

There are a number of areas where transparency plays a key role:

1) ***Understanding Modelling Assumptions and Analysis***

We invite the government to share their assumptions and models with all stakeholders for review and comment. **In California and with the EPA, data is shared openly and quickly to enable more informed dialogue and better decision making.**

2) ***Addressing Consumer Understanding and Behaviour***

In the natural gas sector, consumers need to understand the impact of carbon pricing on the cost of natural gas and other alternative energy sources. **Clearly displaying this information on the monthly bill will help drive the desired change in consumer behavior**. It is also important that the methodology for granting free allowances and the use of the proceeds from allowance auctions are clearly articulated and transparent.

3) ***Clearly Identifying Emissions Attributable to Natural Gas Suppliers***

Consistent with the treatment of natural gas suppliers in Québec's and California's cap-and-trade systems, regulations should only cover natural gas distributors with respect to:

i. emissions attributable to their supply of natural gas to end-users, minus the natural gas supplied to separately covered emitters (such as covered large industrial emitters and natural gas-fired generators); and

ii. emissions from the operation of the utility's facilities (e.g., compressor stations), provided those emissions exceed 25,000 $MTCO_2e$/year.

Under the Ontario system, gas-fired generators should be separately covered, and gas suppliers should not be responsible for emissions from these generators.

4) ***Select an appropriate Baseline to determine supply and allocation of allowances***

California and Quebec took 2 years to set up the system to include transportation, and the natural gas sector was added in year three of the system. **This allowed for the time to gather energy usage information and emissions information to ensure an appropriate supply and allocation of allowances when these significant portions of the economy entered the cap and trade system.** In Ontario, the baseline supply and allocation of allowances should be set using actual, verifiable energy usage information. **Utilizing 2015 and 2016, or 2016 and 2017 data to establish the baseline would be appropriate.**

Theme #3 – Use Auction Proceeds for Cost-Effective Abatement

Natural gas contributes approximately one third of Ontario's greenhouse gas emissions. Government needs to provide the necessary policy, regulatory and technology investment framework to help consumers reduce the emissions intensity within the natural gas sector; otherwise, it will be very difficult to achieve the overall emission reduction targets.

Union Gas believes that there are opportunities for the government and the natural gas sector to support complementary measures that will make a **significant** contribution to the transition of the Ontario economy. In the natural gas sector, such complementary measures could contribute up to **20 $MtCO_2e$ per year** of emissions reductions by 2030. **A portion of auction proceeds should be used to fund the initiatives**.

Union Gas **has identified five areas of focus** which are noted below. Union is also in the process of preparing a detailed solutions paper for government that will clearly identify complementary measures and articulate what is required to realize these significant emissions reductions over the next 15 years.

1) ***Transportation Opportunities***

The government has indicated a desire to push towards electrification of the transportation sector, and an overall increased focus on transportation-related emissions reductions.. There are some segments of the transportation market where electrification is not an option. In the **higher horsepower long-haul heavy-duty transportation, and the return to base fleets, Liquefied Natural Gas/Compressed Natural Gas (LNG/CNG) can play an important role in reducing emissions**. By making the required policy changes and providing the right incentives, emissions reductions up to **3 $MtCO_2e$ per year** by 2030 are achievable. This is the equivalent of replacing 750,000 combustion engine cars with electric vehicles.

2) ***Cap & Trade Energy Conservation (CTEC)***

Since the 1980s, Union Gas has successfully implemented demand side management (DSM) initiatives to reduce the carbon footprint of natural gas consumers throughout our province. There are significant opportunities to expand the energy efficiency activities in which Union Gas already engages under the direction of the OEB. These activities have proven to be a significant source of energy efficiency improvements in the province, and could be expanded with additional funding. The success of these programs is substantial**; the average residential home uses 30% less natural gas than it did 10 years ago.** Union Gas and Enbridge are about to embark on an unprecedented acceleration of energy efficiency activities, investing over $750 million between 2015 and 2020 towards the reduction of greenhouse gas emissions. Union Gas believes that the **DSM programs as overseen by the OEB and included in natural gas distribution rates should continue and expand** to achieve even greater efficiency gains and GHG reductions.

In addition to emissions reductions already being targeted through existing programs, Union has identified an opportunity to further reduce emissions by **9 MtCO$_2$e per year by 2030** through even higher levels of energy conservation

3) ***Renewable Natural Gas***

By 2030, RNG could supplant a significant portion (18 per cent) of the natural gas used in Ontario, resulting in a potential emissions reduction of **8 MtCO$_2$e per** year. If executed correctly, **Ontario has the potential to become a leader with respect to gasification technology** and develop a local industry, with the investment and jobs that come with a leadership position. This approach would use strategic natural gas assets currently in place in Ontario and allow them to play a role in transitioning our economy. RNG produced from sources such as landfills and waste treatment plants can be injected into the natural gas pipeline system.

4) ***Combined Heat and Power (CHP)***

The wider use of natural gas CHP systems would strengthen and secure Ontario's electricity system, better serve industry through increased energy security, and create capacity on the grid that could be used for other purposes (e.g. electric vehicles).. Various stakeholders, including electricity LDCs, suppliers and consultants have been working with the IESO to remove barriers that are currently preventing a wider adoption of CHP. It is important that Ontario's Cap and Trade Program Design does not create a new barrier to CHP adoption.

5) ***Natural Gas-related Innovation***

Ontario will need to become a leader in green technology innovation in order to achieve its 2050 targets. Natural gas consumers will eventually pay a significant amount of the revenue collected from allowance auctions. **It is therefore reasonable that investment in medium and long-term technologies be made that will benefit these consumers. The government should establish a "Green Fund" that invests in promising technologies that will economically reduce greenhouse gas emissions.** There are existing technologies that require additional investment to bring them to market or to spur adoption (such as Micro

CHP and natural gas heat pumps) and could play a role in the net-zero home or new LNG vehicle engines that could help drive our economy.

Further Dialogue

It is in everyone's best interest to ensure that the cap-and-trade framework suits Ontario's unique needs, ensures strong economic growth, stands the test of time, is practical, and maintains Ontario's position as a global leader in reducing greenhouse gas emissions.

Thank you for the opportunity to submit these initial comments. We would welcome the opportunity to discuss our perspectives and recommendations with you in further detail. In the meantime, if you have any questions or comments, please contact me at the coordinates below.

Sincerely,

Steve Baker

President

Union Gas Limited – A Spectra Energy Company

50 Keil Drive North

Chatham, Ontario

N7M 5M1

sbaker@spectraenergy.com

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 5

Preamble: Union indicates the following Guiding Principles:
1. Customers and municipalities who directly benefit from Community Expansion Projects should contribute to the financial viability of the project.
2. Expansion customer contributions to project feasibility should be commensurate with the savings achieved by switching to natural gas.
3. Moderate cross subsidization from existing customers is acceptable, provided long term rate impacts are reasonable.
4. Natural gas distributors should not be exposed to financial risk related to the incremental new community capital investments.

a) Please explain why responding to Government and OEB direction is not a Guiding Principle?

b) Please explain why "Customers should not be exposed to financial risk related to the incremental new community capital investments" is not a Guiding Principle. (should this not also be a consideration so that Union's approach is appropriate – customers are also at financial risk as they ultimately pay for these projects

c) Please explain why the optimum use of available Government Loans and Grants for gas infrastructure development is not included?

Response:

a) The Government and OEB directions are the context for the guiding principles.

b) Please see the responses at Exhibit B.CPA.8 c) and Exhibit B.CPA.11.

c) Optimum use of government loans and grants has not been included because the criteria and processes surrounding the loans and grants have not been developed, and Union does not expect them to become available until 2017 at the earliest. As noted in the response at Exhibit B.CCC.16, Union's understanding is the government expects that Community Expansion Projects would exhaust any available regulatory flexibility before they would become eligible for provincial funding.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p.8

Preamble: The E.B.O. 188 Decision supports an approach that facilitates the expansion of natural gas service while adhering to a key principle that existing ratepayers ultimately be held harmless from rate impacts resulting from the cost of new connections.

a) Does Union disagree with the objectives of The E.B.O. 188 Decision? If so, indicate in detail why this is the case.

b) Please indicate if Union is proposing to Change the E.B.O. 188 approach
   i. only for the current 5 Community Expansion projects,
   ii. for the Opportunity Assessment top 30 projects,
   iii. for the Opportunity Assessment Potential Projects.

c) Why does Union now believe ratepayers should not be held harmless from rate impacts from the cost of connections?

Response:

a) Union believes the intent of the E.B.O. 188 Decision to "hold other customers harmless from the cost of new connections"[1] specifically related to communities that currently do not have access to natural gas warrants review. Union believes the recent provincial policy position supporting extension of natural gas infrastructure to additional rural and northern communities[2] are an appropriate reason for this review.

   The E.B.O. 188 Decision was issued in 1998. Since that time, the energy environment in Ontario has changed significantly, and the savings available from switching from other fuels to natural gas have increased significantly. This has led to heightened interest from communities that don't have access to natural gas. Union believes this heightened interest is a driving factor in the government's recent policy positioning related to natural gas infrastructure. Union's proposal is a direct response to this recent public policy position.

b) Union is seeking exemptions from the E.B.O. 188 requirements for any Community Expansion projects that become feasible at a P.I. of 0.4 or higher. At this time, Union has

[1] Board invitation for proposals, Exhibit A, Tab 1, Appendix A, p. 3.

[2] As evidenced by Minister's mandate letter from the Premier of Ontario, as filed in Exhibit A, Tab 1, Appendix N.

identified five[3] projects (see Exhibit A, Tab 2) that it is seeking approval for. Union's intent is to conduct detailed reviews of other potential Projects, including the Projects identified in Exhibit A, Tab 1, Appendix D. Union will also initiate future requests for approval from the Board for rate recovery for any of those Projects that meet the criteria outlined in Union's proposal.

c) Union believes that the broader economic benefits of extending natural gas infrastructure, as outlined in the response at Exhibit B.CCC.5, warrant consideration of the degree to which existing customers could support the provincial policy position noted above.

Union has structured its proposal to meet the government's desire to complete the maximum number of Projects, and Union has applied its experience, judgment and regulatory precedent to also include a maximum ratepayer impact.

The precedent referenced in the framework issued by the Board in 2014 which stated that the annual cost impact of Union's DSM programs be limited to a maximum of $2.00 per month for a typical residential ratepayer.[4] Union's proposal to limit the maximum ratepayer impact of a Community Expansion Program is entirely consistent with this figure. Please also see the response at Exhibit B.CPA.11.

[3] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

[4] EB 2014-0134, Demand Side Management Framework for Natural Gas Distributors (2015-2020), p. 17, http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0134/Report_Demand_Side_Management_Framework_20141222.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 10
Exhibit A, Tab 1, Appendix E

Preamble: Figure 2 shows the cumulative energy costs a typical residential customer can experience if converting to natural gas. The natural gas cost estimate for year one includes the estimated cost of replacement of existing equipment, or conversion of equipment to natural gas, at a cost of $4,000 and assumes an up-front customer contributions-in-aid-of-construction ("CIAC") payment of $2,500.

a) Please provide the Spreadsheet Model (live) that predicts residential energy cost savings populated with the baseline prediction in Figure 2 and notes on all input assumptions including cost of capital etc.

b) Please provide the supporting energy cost forecasts for each alternative.

c) Specifically provide the future gas price forecast used by Union for the next 10 years. Provide references and as appropriate, reconcile to the latest ICF International gas price forecast provided to Union.

d) Please provide a Table that reconciles the calculations in Figure 2 to those in Exhibit A, Tab 1, Appendix E.

Response:

a) Union provided an Excel version via email, copying the Board. The calculations performed in this Excel file are included as Attachment 2 to Exhibit B.CPA.1. Should any other interested parties wish to receive the document, please contact Union directly.

   Figure 2 is an illustrative example that shows the cumulative energy costs a typical residential customer can experience if converting to natural gas. The figure extrapolates savings at current energy prices over a 10-year period. It does not represent discounted cash flows or provide for future energy prices.

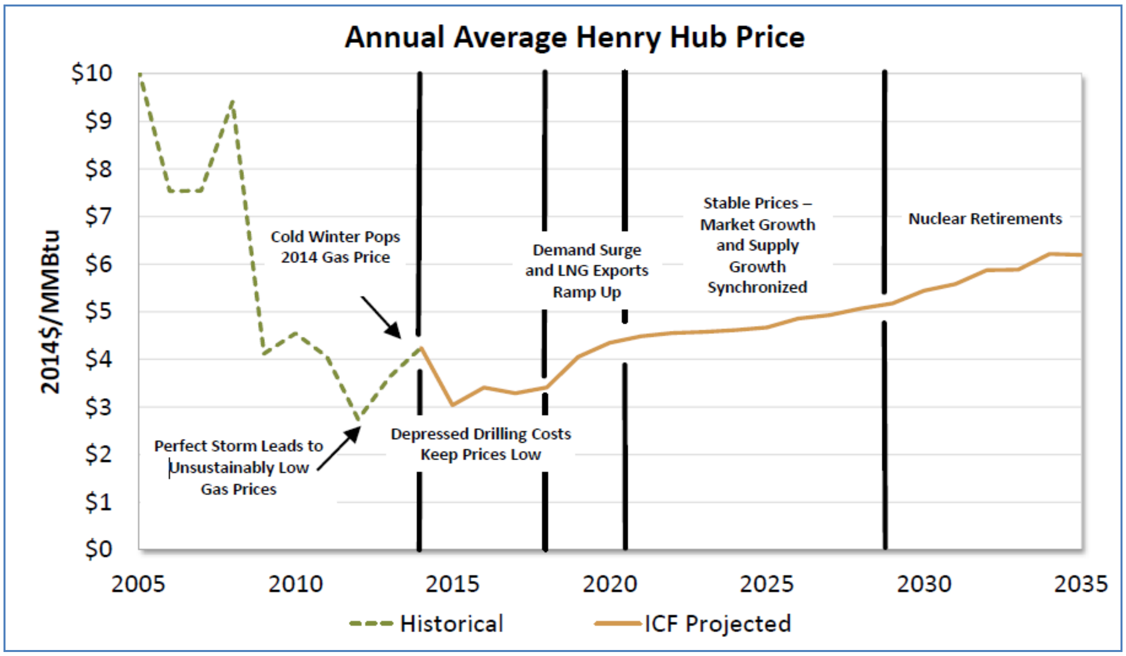
   Please see the response at Exhibit CCC.6 and Exhibit B.CPA.1 a) i) and ii) for details on Figures 1 and 2.

b) Please see part a) above.

c) As noted in part a) above, the illustrative example does not account for future price changes. As a result it cannot be reconciled to the latest ICF International gas price forecast.

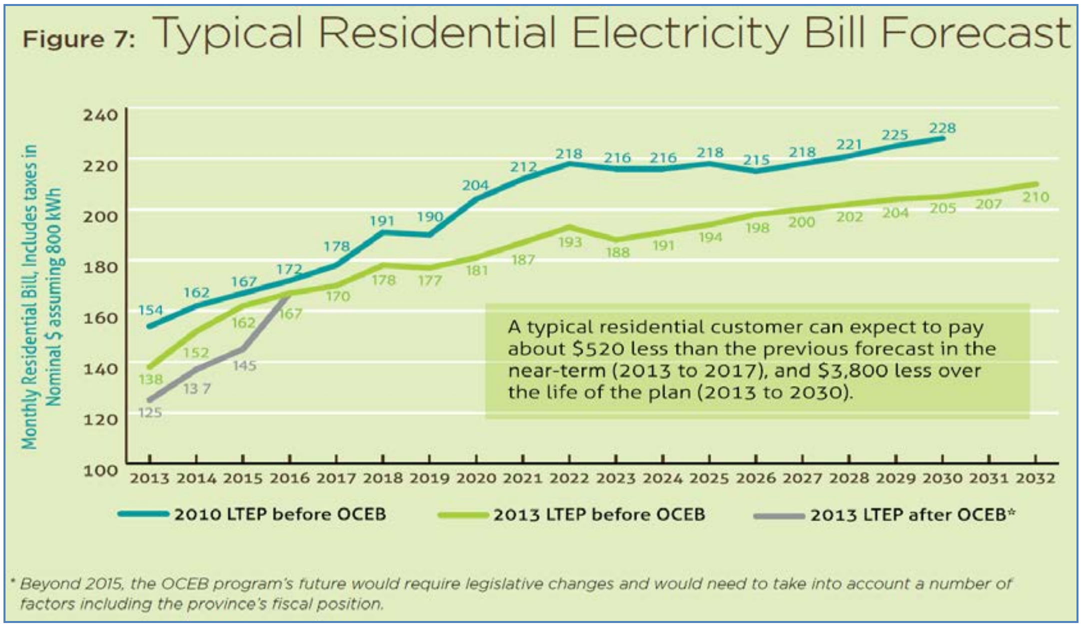
Below Union has provided the latest ICF International gas price forecast, as provided to Union in July 2015.

In the near term, to 2016, prices of natural gas at Henry Hub are expected to continue to range between $3.00 to $4.00 USD/mmbtu. In the long term, between 2020 and 2030, gas prices at Henry Hub are expected to range between $4.50 to $6.00 USD/mmbtu.

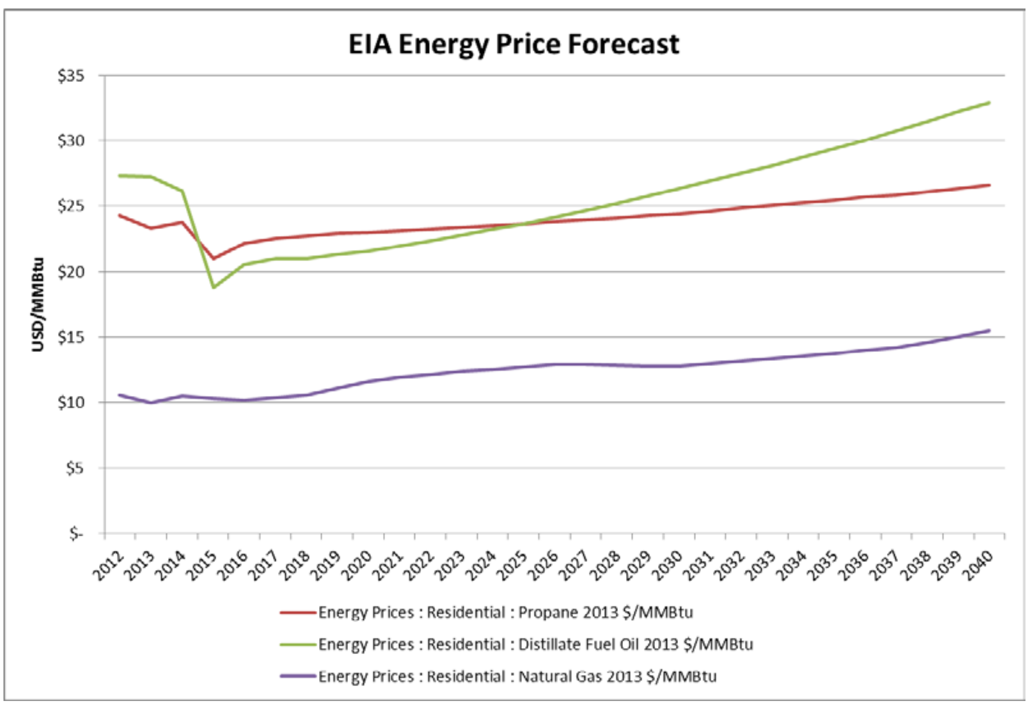


Below is a figure showing a typical residential electricity bill forecast from Ontario's Long-Term Energy Plan.

The figure shows electricity costs in 2032 being $0.2625/kwh. Annual costs of 82 GJ of electricity (the typical annual energy use of a residential gas customer) at this price would amount to approximately $6,000 per year.



Below is a figure showing the US Energy Information Administration (EIA) forecast[1] of residential prices of natural gas, propane, and fuel oil in US$/MMBtu. During the period 2015 to 2040, the spread between natural gas and propane and fuel oil is steady or increasing into the future.



[1] Source: U.S. Energy Information Administration

d) Figure 2 cannot be reconciled with Exhibit A, Tab 1, Appendix E. The intent of Figure 2 is outlined in part a) above. Figure 2 provides estimated energy costs for differing energy sources, including equipment conversions costs in the case of natural gas as well as an assumed required up-front Aid-to-Construction payment of $2,500. It does not factor in the TES proposed by Union.

   The purpose of Exhibit A, Tab 1, Appendix E is to demonstrate how Union calculated a TES rate that would support a simple payback period for a residential customer of less than four years.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 10
Exhibit A, Tab 1, Appendix E

Preamble: Energy Probe wishes to understand in the framework of IRP, if OPA/IESO CDM programs for Electricity distributors e.g. Hydro One, may facilitate conversion from Electricity to Natural Gas and whether also DSM programs are available for home retrofit and furnace upgrades.

a) Has Union determined/assessed if customers converting from electricity to gas can access CDM programs and incentives? If so, provide a précis of the available programs/incentives.

b) In preparing its savings estimates, did Union take into account all such assistance/programs. If not why not?

c) Did Union take into account assistance from its own proposed DSM programs for homeowners and particularly for Low Income households? Please summarize the available assistance, including retrofit measures and furnace replacement.

d) Please rerun Savings Scenarios for typical households with available incentives from

i) CDM (assume an electricity price forecast) and
ii) DSM programs (using future gas price forecast)

Please summarize all input assumptions and provide the results in Excel format in the same Workbook requested at Exhibit B.Energy Probe.5 a).

e) Given the Boards Policy on IRP, please describe the specific steps Union has taken to implement IRP methodology in planning for these projects.

Response:

a) It is Union's understanding that currently CDM programs and incentives are not available to residential customers to convert from electricity to natural gas.

b) Based on a) above, these is no need for this assessment.

c) Union has a suite of DSM offerings available for customers, as detailed in its 2015-2020 DSM Plan (EB-2015-0029[1]). Union did not take these programs into account when estimating the impacts of its proposals, however, Union believes they would marginally increase savings available on average, but would not materially affect the impacts.

   The following is a very brief summary of the offerings:

   - A Home Renovation incentive program for residential customers, offering financial incentives for energy efficient upgrades to home energy using equipment as well as the building shell (for example insulation),
   - A low income single family program for which Union installs energy saving measures, such as thermal insulation, in the home at no cost to the resident,
   - Commercial/Industrial energy efficiency programs which provide financial incentives for the installation of qualifying higher efficiency equipment or building shell improvements,
   - A low income multi-family building program whereby Union offers improved financial incentives for the commercial program outlined above.

   If the Board approves Union's DSM Plan as filed, Union would make these offerings available to potential customers that intend to be served by Community Expansion Projects, provided they have completed an application for service, and provided payment of incentives for any measures installed are suspended until such time as they have activated their service.

d) As noted in part c) above, Union has various DSM programs that would be available to customers in the potential Project areas, and would expect that customers would participate in applicable programs to the same extent they do across the remainder of Union's franchise areas. In the absence of knowing how any available CDM programs might be applied for electricity customers, or expected participation rates, Union is not able to provide a revised average savings scenario.

e) As outlined in EB-2015-0029, Union will be completing a study on the role of DSM in infrastructure planning in time to inform the mid-term review required under the Demand Side Management Framework for Natural Gas Distributors (EB-2014-0134).

[1] A Board decision on this proceeding is pending.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation (“Energy Probe”)

Reference: Exhibit A, Tab 1, p. 12

Preamble: Union states that "despite the increasing number of conversion customer attachments, very few of these customer attachments were in 'new -to-gas' communities. In the past decade Union has only expanded to one new community requiring Board facilities approval, Red Lake”.

a) Is it correct that the primary reason that Union has not expanded to new communities is because the economics of those projects were unfavourable (having a Profitability Index of less than 1.0).

b) Please explain how many projects were rejected due to economics or other considerations.

c) Please provide the rationale to proceed with the expansion to Red Lake.

Response:

a) Yes.

b) Union is not aware of how many projects were rejected. It can confirm that over 50 of the Projects listed in Exhibit A, Tab 1, Appendix D have been considered and rejected in the past due to poor economic feasibility, as shown in Attachment 1 at Exhibit B.EGD.5. The row numbers in Attachment 1 correspond to the row numbers in Exhibit A, Tab 1, Appendix D.

c) With the support of funding partners who contributed an Aid-to-Construction, Union was able to combine service to a large industrial customer and to the Municipality of Red Lake.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 16

Preamble: Union states: "The proposed TES provides a means of satisfying the principle that those that benefit from expansion should bear a share of the costs, as well as the principle that customer contributions to project feasibility be commensurate with the savings they achieve by switching from other energy sources to natural gas."

a) Does the proposal mean that large volume customers will be cross subsidizing low volume customers, as the costs to service the two customers may be similar, while the TES charges will be significantly higher for one? Please explain.

b) Did Union consider a fixed charge? Please discuss.

Response:

a) The TES is only proposed to be used for general service customers. The general service customers that have higher annual consumption will contribute more to the Project feasibility than low volume general service customers; however, they will also save substantially more from converting to natural gas.

   Having a proposal that required all customers to pay the same amount despite the wide range in annual savings they could experience would not satisfy the principle that customer contributions to project feasibility be commensurate with the energy savings achieved.

b) Union considered a fixed monthly rate as opposed to a volumetric rate. At the proposed annual cost equivalent, a TES in this form would require a rate of about $42 per month, in additional to the existing fixed monthly charge of $21. Union was concerned that at a total fixed cost of $63 per month, water heater conversions might be jeopardized as a customer without a gas water heater might be incented to turn off their meter for the warmer months. In addition to this concern, taking a fixed rate recovery approach would result in less TES being collected since larger customers, who consume more natural gas, would not pay any additional share of their annual savings from converting. This approach would not satisfy the principle that customer contributions to project feasibility be commensurate with the energy savings achieved. A higher fixed rate or additional Aid-to Construction would be necessary to offset the detrimental impact on project economics.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 16-17

Preamble: An additional barrier is the CIAC mechanism applying only to those customers who attach in the year a project goes into service. Customers who delay attaching until future years can avoid paying their share of the CIAC. As proposed, the TES mitigates the incentive for customers to delay connection by ensuring all customers who attach during the TES period associated with the project feasibility analysis pay the TES.

a) Please provide the forecast of customer attachments for each project.

b) Please provide the TES period for each of the 5 Community Expansion Projects.

c) Please indicate the customer attachments forecast during the period of the TES.

d) If the TES period was extended to 10 years, how would this impact the forecast attachment? Please be specific for each project.

Response:

a) Please refer to the schedules at Exhibit A, Tab 2, for the attachment forecast.

b) The TES period is provided at Exhibit A, Tab 1, p.45, Table 8.

c) Customer attachments forecast during the term of the TES period can be determined by comparing the response to a) above to the TES/ITE months from Exhibit A, Tab 1, Appendix D.

d) When Union was surveying, it did not identify a specific timeframe for the length of the TES, other than a five to 10 year range. Union does not expect that the length of time that the TES was collected would change the attachment forecast, provided it did not extend past 10 years.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation (“Energy Probe”)

Reference: Exhibit A, Tab 1, p. 19

a) Please provide the sources for all the data used to generate Table 2.

b) For what year(s) are the costs applicable?

c) Please provide a comparable Table for Water Heating Costs.

d) Please provide a Table that shows/combines costs for each of Space and Water Heating.

Response:

a) Please see the response at Exhibit B.CPA.1a) ii).

b) The costs are applicable for 2015.

c) Please see the response to d) below.

d) In populating the table below, Union assumed a 50 U.S. gallon power vented water heater would be installed in all instances. Approximate costs for water heating conversions were determined through discussions with a contractor.

Estimated Heating/Water Heating Equipment Replacement/Conversion Costs

Fuel	Heating Equipment and Fuel	Heating Distribution	Estimated Heating Conversion Cost	Water Heating Distribution	Estimated Water Heating Conversion Cost	Water Heater Monthly Rental Rate
Oil	Boiler	32%	$4,200	13%	$1,500	$26
	Forced Air	3%	$4,200			
Propane	Boiler	1%	$4,000	8%	$1,500	$26
	Forced Air	12%	$1,525			
	Space Heater	2%	$3,500			
Electric	Electric Baseboard	6%	$11,000	79%	$1,500	$26
	Forced Air	12%	$4,000			
	Heat Pump /Hydronic	4%	$4,000			
Wood	Wood (assumed wood stove)	28%	$3,500	0%	N/A	N/A
Weighted Average		**100%**	**$4,068**	**100%**	**$1,500**	**$26**

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 23- E.B.O.188 Exemption: Minimum Project PI Threshold

Preamble: Union proposes an exemption from E.B.O. 188 that would allow the minimum economic threshold for Community Expansion Projects to be lowered to a PI of 0.4 from the current minimum of 0.8.

a) Please indicate if this minimum PI of 0.4 is before or after including TES, ITE and CIAC revenues.

b) Please indicate why Union is proposing a minimum PI of 0.4 rather than any other level.

c) Is 0.4 a minimum PI threshold for all projects proposed to be implemented from the Opportunity Assessment? Please explain.

Response:

a) The minimum P.I. of 0.4 is after including TES, ITE, and any necessary Aid-to-Construction.

b) A minimum P.I. of 0.4 best satisfies the government's goal of expanding to as many communities as possible while at the same time ensuring the long-term rate impacts for current ratepayers remain reasonable. Please also see the response at Exhibit B.SEC.13.

c) Yes. No further projects would be put forward for approval unless the economics for those projects indicate a P.I. of 0.4 or higher, after accounting for the TES, ITE, and any necessary residual Aid-to-Construction.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, Page 25, Figure 4 and
Exhibit A, Tab 1, Appendix D.

Preamble: The main reason for the increase in customers that could be served as the PI decreases from 0.5 to 0.4 is the impact of a large project that becomes feasible at 0.4. This project would provide access to natural gas to over 9,000 potential customers in the communities of Kincardine, Tiverton, Paisley and Chesley.

a) Please explain why the Kincardine, Tiverton, Paisley and Chesley Project is being advanced when it has a natural PI of 0.18.

b) Please explain why it is appropriate that the PI minimum should be decreased from 0.5 to 0.4 to accommodate this project.

c) Please confirm/provide the following resulting impacts:
- Cost /Customer
- Total Capital cost
- Cost/rate impact to existing customers

d) Please provide a scenario with a Provincial CIAC loan/grant to make the minimum PI threshold 0.5 for this and other top 30 projects.

Response:

a) The Kincardine area is the largest community in Ontario that does not have access to natural gas. The Kincardine area was identified as one of the 30 potential projects because after including TES and ITE for a period of 8.6 years, the Project could achieve a P.I. of 0.4.

Union is not advancing this project at this point. Detailed costing and new market surveys would be required in order to develop a Leave-to-Construct application for the Board along with a request for any revenue deficiency.

Since developing the information for the Kincardine-area Project as presented in Exhibit A, Tab 1, Appendix D, Union has undertaken further analysis and a costing review of that project, as well as an adjacent project to serve Ripley and Lucknow. The result of that analysis is provided in Exhibit B.South Bruce.6. The natural P.I. before including TES or ITE would be 0.23.

b) Please see the response at Exhibit B.Energy Probe.11 b).

c) Union has updated the Kincardine-area Project with information that was not available at the time Exhibit A, Tab 1, Appendix D was filed. Based on the updated information, the Kincardine-area Project would have a gross capital cost of $66 million, and a natural P.I. (before considering TES or ITE) of 0.23. Capital cost per forecasted customer would be $18,960. Attachment 1 provides the bill impacts of the revised Kincardine-area Project for an average residential Rate M1 and Rate 01 customer consuming 2,200 m^3 annually.

d) This scenario is presented in Exhibit A, Tab 1, Appendix D (Updated), pp. 1-3, in the columns labelled "Including TES/ITE, min P.I.=0.5, CIAC Required". Applying the criteria above would result in:

- 20 potential projects that would not require Aid-to-Construction, listed in Exhibit A, Tab 1, Appendix D (Updated), p. 1, lines 1 to 23, but excluding lines 4[1], 16 and 18. The gross capital expenditure for these Projects would be $48 million.

- The remaining nine projects would require $5 million in Aid-to-Construction which might be satisfied by means of applying government grants or loans. These projects are listed in Exhibit A, Tab 1, Appendix D (Updated), lines 24 to 33, but excluding line 30. Net capital for these nine projects will be $82 million.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impact of Revised Kincardine Project
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (a)	Excluding Kincardine Total Bill (1) ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	86.15	82.57	3.58	
3	Storage Services	16.28	16.30	(0.02)	
4	Total Delivery Charge	354.43	350.87	3.57	1.0%
	Supply Charges				
5	Transportation to Union	83.37	83.37	-	
6	Commodity & Fuel	274.03	274.03	-	
7	Total Gas Supply Charge	357.40	357.40	-	
8	Total Bill (line 4 + line 7)	711.84	708.27	3.57	0.5%
9	Impacts for Customer Notices - Sales (line 8)			3.57	
10	Impacts for Customer Notices - Direct Purchase (line 4)			3.57	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (a)	Excluding Kincardine Total Bill (1) ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
11	Monthly Charge	252.00	252.00	-	
12	Delivery Commodity Charge	197.27	198.32	(1.05)	
13	Total Delivery Charge	449.27	450.32	(1.05)	-0.2%
	Supply Charges				
14	Transportation to Union	172.44	172.43	0.00	
15	Storage Services	95.52	95.56	(0.04)	
16	Subtotal	267.96	267.99	(0.03)	0.0%
17	Commodity & Fuel	274.26	274.26	-	
18	Total Gas Supply Charge (line 16 + line 17)	542.22	542.25	(0.03)	
19	Total Bill (line 13 + line 18)	991.49	992.57	(1.08)	-0.1%
20	Impacts for Customer Notices - Sales (line 19)			(1.08)	
21	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			(1.08)	

Notes:
(1) per Exhibit B.LPMA.22 Attachment 4, p.1.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impact of Revised Kincardine Project Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (a)	Excluding Kincardine Total Bill (1) ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	86.15	82.57	3.58	
3	Delivery Price Adjustment	(1.54)	(0.57)	(0.97)	
4	Storage Services	16.28	16.30	(0.02)	
5	Total Delivery Charge	352.89	350.30	2.59	0.7%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	710.29	707.70	2.59	0.4%
10	Impacts for Customer Notices - Sales (line 9)			2.59	
11	Impacts for Customer Notices - Direct Purchase (line 5)			2.59	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (a)	Excluding Kincardine Total Bill (1) ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	197.27	198.32	(1.05)	
14	Delivery Price Adjustment	(1.22)	(1.55)	0.33	
15	Total Delivery Charge	448.05	448.77	(0.72)	-0.2%
	Supply Charges				
16	Transportation to Union	172.44	172.43	0.00	
17	Storage Services	95.52	95.56	(0.04)	
18	Subtotal	267.96	267.99	(0.03)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.22	542.25	(0.03)	
21	Total Bill (line 13 + line 18)	990.27	991.02	(0.75)	-0.1%
22	Impacts for Customer Notices - Sales (line 21)			(0.75)	
23	Impacts for Customer Notices - Direct Purchase (line 15 + line 18)			(0.75)	

Notes:
(1) per Exhibit B.LPMA.22 Attachment 4, p.2.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 25
Exhibit A, Tab 1, Appendix D

Preamble: Table 3 provides a summary of the projects that may become feasible at each PI level without a need for CIAC sourced from the grants and loans announced by the Province.

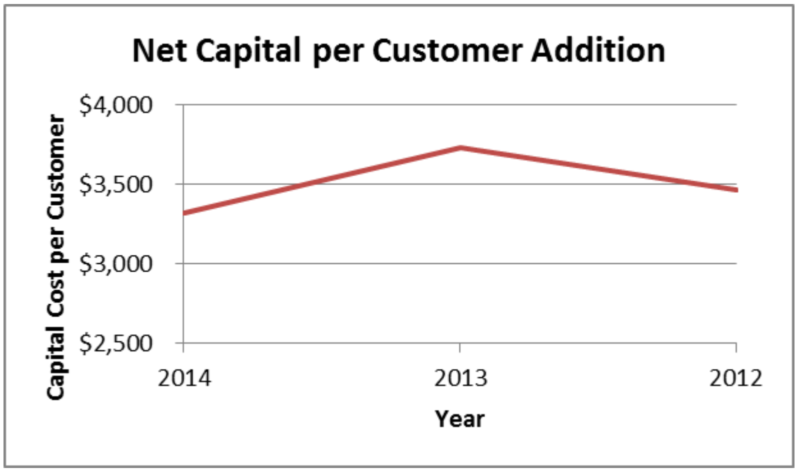
a) Please provide in both tabular and graphical form the Unit Capital cost to service customers for the recent (last 3 years) OEB approved System Expansion Projects.

b) Please provide in both tabular and graphical form the Unit Capital cost to service the current 5 Projects and the top 30 Opportunity Assessment projects.

Response:

a) Union has provided the capital cost per customer added to the distribution system below. Please note the table includes all connections to Union's system each year, including services that are attached to main that was installed in prior years. The Red Lake Project in 2012 was the only project that required Leave-to-Construct approval from the Board. The number of services installed for that project is provided at Exhibit B.Staff.14, Attachment 1.

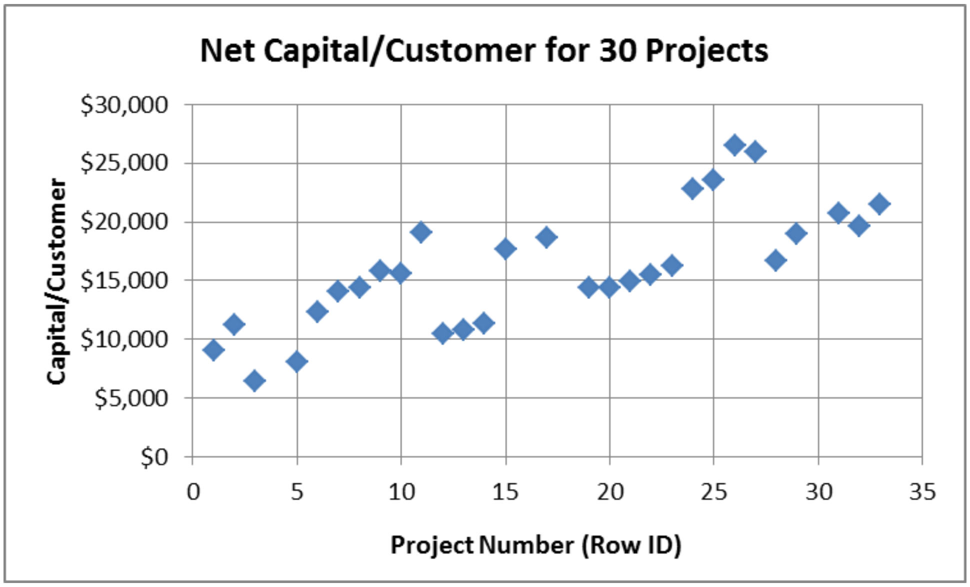
Year	Net Capital (million)	Added Customers	Net Capital per Customer
2014	$70.3	21,164	$3,321
2013	$75.5	20,259	$3,726
2012	$71.2	20,566	$3,462



b) Please see below. Note that in the graph, the project numbers correspond to the Row number in the chart as well as in Exhibit A, Tab 1, Appendix D[1].

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

Row	Community Name	Net Capital per Forecast Customer
1	Milverton	$9,062
2	Prince Township, Sault Ste Marie	$11,223
3	Lambton Shores, Kettle Point First Nation	$6,381
4	~~Walpole Island First Nation- main commercial area~~	
5	Moraviantown First Nation- main commercial area	$8,045
6	Lagoon City (Orillia)	$12,342
7	Hidden Valley/Huntsville	$14,026
8	Santa's Village/Beaumont Dr, Bracebridge	$14,342
9	Canal, Gravenhurst	$15,859
10	Northshore Rd / Peninsula Rd North Bay	$15,607
11	Hornby	$19,118
12	Oneida First Nation	$10,473
13	Auburn	$10,750
14	Cedar Springs	$11,344
15	Astorville	$17,682
17	Nipissing First Nation / Jocko Point	$18,643
19	Chippewa of the Thames First Nation- phase 3 & 4	$14,423
20	Sheffield	$14,435
21	Turkey Point	$14,964
22	Rockton	$15,508
23	Chippewas of the Saugeen	$16,200
24	Washago	$22,769
25	E Floral (T Bay area)	$23,554
26	Haldimand Shores	$26,495
27	Latchford, Tri Town	$26,005
28	Belwood	$16,732
29	Kincardine. Tiverton, Paisley, Chesley	$18,960
31	Swiss Meadow	$20,766
32	Boblo Island	$19,577
33	Village of Warwick	$21,514


Net Capital/Customer for 30 Projects
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
Capital/Customer
0
5
10
15
20
25
30
35
Project Number (Row ID)

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 31

Preamble: Union proposes to adjust rates annually to recover the forecasted net revenue requirement associated with the gross capital investment for all Community Expansion Projects. Consistent with Union's current practice, gross capital will be reduced by any upfront CIAC that is received (i.e. provincial funding). In addition, Union proposes to create a deferral account (see Section 4.6) to capture the variances between the forecast net revenue requirement and the actual net revenue requirement for the Community Expansion Projects.

a) Please provide a Summary Table that provides the Rate class impacts by year for each of the 5 projects.

b) Please provide a table providing the amount of money that to be spent on the proposed community expansion projects that will come from:
- current residential natural gas ratepayers,
- ratepayers that are being connected through the new program,
- municipal governments and
- provincial taxpayers (in the form of government grants and loans).

Response:

a) Please see Attachment 1 for the revenue requirement by rate class for 2016 to 2018 for each of the four proposed Community Expansion Projects requested in this Application[1].

b) In the context of the question Union interprets the phrase "the amount of money that to be spent …." (emphasis added) to mean the NPV of the resulting revenue that will come from each group referenced in the question assuming Union's proposal is accepted.

To respond on the basis of "current residential natural gas ratepayers" (emphasis added) would require a cost study assessment over a 40 year period. As an alternative, Attachment 2 uses the NPV of the project after the collection of all other contributions. The NPV is the shortfall borne by all customers (all existing customer as well as new expansion customers in all rate classes). Please see Attachment 2.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED
Milverton Community Expansion Project Revenue Requirement by Rate Class

Line No.	Particulars ($000's)	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)
1	Rate M1	119	214	333	14	347
2	Rate M2	22	38	60	0	60
3	Rate M4	6	10	16	0	16
4	Rate M5	8	14	23	0	23
5	Rate M7	1	3	4	0	4
6	Rate M9	(0)	(0)	(0)	0	0
7	Rate M10	0	(0)	0	0	0
8	Rate T1	4	7	11	0	11
9	Rate T2	6	11	17	0	17
10	Rate T3	(0)	(0)	(0)	0	(0)
11	Subtotal - Union South	167	298	464	15	479
12	Excess Utility Space	(0)	(0)	(0)	0	(0)
13	Rate C1	(0)	(0)	(0)	0	(0)
14	Rate M12	(3)	(1)	(4)	1	(4)
15	Rate M13	(0)	(0)	(0)	0	(0)
16	Rate M16	(0)	(0)	(0)	0	(0)
17	Subtotal - Ex-franchise	(3)	(1)	(5)	1	(4)
18	Rate 01	(11)	(18)	(29)	0	(29)
19	Rate 10	(2)	(3)	(5)	0	(5)
20	Rate 20	(2)	(3)	(5)	0	(5)
21	Rate 100	(1)	(3)	(4)	0	(4)
22	Rate 25	(1)	(1)	(1)	0	(1)
23	Subtotal - Union North	(17)	(27)	(44)	1	(43)
24	In-franchise	150	270	420	15	436
25	Ex-franchise	(3)	(1)	(5)	1	(4)
26	Total	146	269	416	16	431

UNION GAS LIMITED
Prince Township Community Expansion Project Revenue Requirement by Rate Class

Line No.	Particulars ($000's)	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)
1	Rate M1	(9)	(13)	(22)	(0)	(22)
2	Rate M2	(2)	(3)	(5)	0	(5)
3	Rate M4	(1)	(1)	(1)	0	(1)
4	Rate M5	(1)	(1)	(2)	0	(2)
5	Rate M7	(0)	(0)	(0)	0	(0)
6	Rate M9	(0)	(0)	(0)	0	(0)
7	Rate M10	(0)	(0)	(0)	0	(0)
8	Rate T1	(0)	(1)	(1)	0	(1)
9	Rate T2	(1)	(1)	(1)	0	(1)
10	Rate T3	(0)	(0)	(0)	0	(0)
11	Subtotal - Union South	(13)	(20)	(33)	(0)	(33)
12	Excess Utility Space	(0)	(0)	(0)	0	(0)
13	Rate C1	(0)	(0)	(0)	0	(0)
14	Rate M12	(2)	(1)	(3)	0	(2)
15	Rate M13	(0)	(0)	(0)	0	(0)
16	Rate M16	(0)	(0)	(0)	0	(0)
17	Subtotal - Ex-franchise	(2)	(1)	(3)	0	(3)
18	Rate 01	29	54	83	14	97
19	Rate 10	11	18	29	(0)	29
20	Rate 20	21	37	58	(1)	57
21	Rate 100	27	47	74	(1)	73
22	Rate 25	5	9	14	(0)	14
23	Subtotal - Union North	93	165	259	12	270
24	In-franchise	80	146	226	12	237
25	Ex-franchise	(2)	(1)	(3)	0	(3)
26	Total	78	145	223	12	235

UNION GAS LIMITED
Chippewa's of Kettle and Stony Point First Nation and Lambton Shores Community Expansion Project
Revenue Requirement by Rate Class

Line No.	Particulars ($000's)	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)
1	Rate M1	61	53	114	64	178
2	Rate M2	11	47	58	(28)	30
3	Rate M4	3	14	17	(9)	8
4	Rate M5	4	19	23	(12)	11
5	Rate M7	1	3	3	(1)	2
6	Rate M9	(0)	0	0	0	0
7	Rate M10	0	0	0	0	0
8	Rate T1	2	9	11	(6)	6
9	Rate T2	3	7	10	(1)	9
10	Rate T3	(0)	0	(0)	0	(0)
11	Subtotal - Union South	85	152	236	7	244
12	Excess Utility Space	(0)	(0)	(0)	0	(0)
13	Rate C1	(0)	(0)	(0)	0	(0)
14	Rate M12	(2)	(1)	(2)	0	(2)
15	Rate M13	(0)	(0)	(0)	0	(0)
16	Rate M16	(0)	(0)	(0)	0	(0)
17	Subtotal - Ex-franchise	(2)	(1)	(3)	0	(2)
18	Rate 01	(6)	(9)	(15)	0	(15)
19	Rate 10	(1)	(2)	(3)	0	(2)
20	Rate 20	(1)	(1)	(2)	0	(2)
21	Rate 100	(1)	(1)	(2)	0	(2)
22	Rate 25	(0)	(0)	(1)	0	(1)
23	Subtotal - Union North	(9)	(14)	(23)	0	(22)
24	In-franchise	76	138	214	8	221
25	Ex-franchise	(2)	(1)	(3)	0	(2)
26	Total	74	137	211	8	219

UNION GAS LIMITED
Delaware Nation of Moraviantown Community Expansion Project Revenue Requirement by Rate Class

Line No.	Particulars ($000's)	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)
1	Rate M1	15	27	42	1	43
2	Rate M2	3	5	8	(0)	8
3	Rate M4	1	1	2	(0)	2
4	Rate M5	1	2	3	(0)	3
5	Rate M7	0	0	1	0	1
6	Rate M9	(0)	(0)	(0)	0	(0)
7	Rate M10	(0)	0	0	0	0
8	Rate T1	1	1	1	(0)	1
9	Rate T2	1	1	2	0	2
10	Rate T3	(0)	(0)	(0)	0	(0)
11	Subtotal - Union South	21	37	59	1	59
12	Excess Utility Space	(0)	(0)	(0)	0	(0)
13	Rate C1	(0)	(0)	(0)	0	(0)
14	Rate M12	(0)	(0)	(1)	0	(1)
15	Rate M13	(0)	(0)	(0)	0	(0)
16	Rate M16	(0)	(0)	(0)	0	(0)
17	Subtotal - Ex-franchise	(0)	(0)	(1)	0	(1)
18	Rate 01	(2)	(2)	(4)	0	(3)
19	Rate 10	(0)	(0)	(1)	0	(1)
20	Rate 20	(0)	(0)	(1)	0	(1)
21	Rate 100	(0)	(0)	(1)	0	(0)
22	Rate 25	(0)	(0)	(0)	0	(0)
23	Subtotal - Union North	(2)	(3)	(6)	0	(5)
24	In-franchise	19	34	53	1	54
25	Ex-franchise	(0)	(0)	(1)	0	(1)
26	Total	19	34	52	1	53

Line	Figures are NPV in $ 000's	Project 1 (a)	Project 2 (b)	Project 3 (c)	Project 4 (d)	Total (e)= Sum (a) to (d)
1	Distribution Revenue from New Expansion Customers	1,466	2,905	323	1,597	6,291
2	TES Collected from New Expansion Customers	509	1,015	97	223	1,844
3	ITC collected from Municipalities	13	183	18	93	307
4	Provincial Government (Grants and Loans)	-	-	-	-	-
5	All current and future ratepayers	964	1,832	177	1,333	4,306

As of this date the figures for Provincial governments grants and loans is not known

	Project	Evidence
1	Kettle Point/ Lambton Shores	Exhibt A, Tab 2, Section A
2	Milverton	Exhibt A, Tab 2, Section B
3	Moraviantown	Exhibt A, Tab 2, Section C
4	Prince Township	Exhibt A, Tab 2, Section D

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 35

Preamble: Union is seeking approval of five projects in this application.

For the remaining 25 that can be serviced under its Proposal, Union will continue to file leave to construct ("LTC") applications for those expansion projects that meet the Board's LTC criteria. The LTC applications will include the requests for approval of the net revenue requirement associated with the projects. Union will also apply for franchise and certificate applications if necessary.

For those projects that do not meet the Board's LTC criteria, Union will file an application for approval of the forecast net revenue requirements. Union will then include the approved net revenue requirement impacts for all the approved projects in its next annual rate-setting application.

a) Please explain why the E.B.O. 188 Exemption applies beyond the 5 projects in the existing Application.

b) Please explain why the CE Plan should not involve phasing projects to mitigate rate impacts.

c) Please explain why all CE Applications that do not meet E.B.O. 188 should not be filed with full information on feasibility, economic benefits and rate impacts.

Response:

a) Please see the response at Exhibit B.CCC.3.

b) Union intends to phase in the Projects. Union's proposal will cause the rate impacts to be phased in, through a combination of the TES/ITE deferral[1], and the timing for construction of the potential Projects.

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

[1] The Community Expansion Contribution Deferral Account ("CECDA") referenced at Exhibit A, Tab 1, p.33.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 42

Preamble: Union indicates the criteria and form of funding from the announced provincial funding are unknown at this time.

Please discuss the timing of when the criteria and form of funding will be known.

Response:

Please see the response at Exhibit B.CCC.16.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, p. 4, Small Main Extension Project Proposal Tab 3, Appendix O

Preamble: The parameters of Union's proposals have been set to achieve the following objectives:
1. Temporary Connection Surcharge ("TCS") rate for smaller main extension projects.
2. To maximize the number of new communities to receive natural gas service without the use of provincial funding support, and
3. To limit the rate impacts on existing customers to a maximum approximating $2 per month ($24 per year) over the multi-year expansion program.

a) Please indicate if the TCS rate and the TES rate are identical. If not, explain the differences.

b) Please indicate if the above rate impacts are included or on top of the subsidy/impact from the Community Projects. Please provide the combined total.

c) Please provide a list of prospective Small Main Extension Projects with timing and estimated costs.

d) If available, provide information on estimated PIs without TCS.

Response:

a) The TCS as proposed in Exhibit A, Tab 3, is not applicable to Community Expansion Projects, and is a separate proposal from Union's proposal for Community Expansion projects as filed in Exhibit A, Tab 1. The TCS is only intended for use in situations where Union's Community Expansion Project criteria do not apply. Examples of these types of projects can be found at Exhibit B.Staff.15. The TCS provides an alternative to CIAC for a customer who wishes to attach to Union's system where a Community Expansion Project is not occurring.

The TCS and TES are only similar in that the same rate (both are proposed at $0.23/m^3$) and maximum term (up to 10 years) are proposed for both.

A major difference between the TCS and TES is that because Union is not proposing any form of capital pass-through for smaller main extension projects (non-Community Expansion Projects), the TCS will not be collected in a deferral account to be disposed to ratepayers.

Union is seeking approval to apply the TCS charge to the bills of applicable customers who are attaching the system for a period of up to 10 years beginning at the time the project to serve them goes into service.

Assuming full 10 year TCS periods are required for two projects to make them feasible at a minimum P.I. of 1.0, if Union put one project into service in December of 2015, and a different project in December of 2018, the TCS would expire after December 2025 for the first project, and after December 2028 for the second project. In this case the TCS would be in use for 13 years.

b) The parameters provided in Exhibit A, Tab 1, p. 4 refer to Community Expansion Projects, not small main extension projects. There would be no revenue deficiency to recover for small main extension projects. Projects that do not meet the criteria for Community Expansion Projects will continue to require a minimum P.I. of 1.0. At this P.I., there are no longer term ratepayer impacts for these projects. At P.I.'s above 1.0, there are longer term ratepayer benefits.

c) Union does not maintain a list of prospective small projects, because they are routinely requested, planned and constructed on an ongoing basis within each calendar year in accordance with Union's Distribution New Business Guidelines, which are filed in Exhibit A, Tab 1, Appendices H and I.

d) Estimated P.I.'s without using TCS would still be 1.0 or above, because Aid-to-Construction would be required before proceeding, in accordance with Union's Distribution New Business Guidelines. The P.I.'s of all these projects combined is reflected in Union's Rolling Project Portfolio, for which the most recent three year average P.I. is 1.48, as shown in Exhibit A, Tab 1, Table 4.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, Appendix H-Distribution New Business Guidelines

a) Please provide a Blackline version of the revised Guidelines.

b) Please indicate if the revised Guidelines will apply generally or to only the Opportunity Assessment Community expansion Projects.

Response:

a) Please see Attachment 1.

b) The guidelines will apply generally to all Distribution expansion work.

Union's ~~Current~~Revised Distribution New Business Guidelines

DISTRIBUTION NEW BUSINESS GUIDELINES[1]

Purpose

- To ensure that customers are treated fairly and consistently.
- To manage growth of the natural gas distribution business by providing guidelines for capital investment to ensure no undue rate impact for existing customers.
- To provide business principles and guidelines for distribution new business investments.
- To streamline administrative processes and approvals where possible.
- To delegate authority where appropriate to field operations staff.

Definitions

Aid to Construction ("Aid"): A financial contribution to the capital costs of a natural gas system extension, also called Aid

Community Expansion Project: A natural gas system expansion project which will provide first time natural gas system access where a minimum of 50 potential customers in homes and businesses already exist, for which minimum economic feasibility guidelines permit a Profitability Index ("PI") of less than 1.0.

Distribution New Business ~~– is defined as providing~~: Providing gas service to new customers in all market segments (i.e. new and existing housing, commercial and industrial~~) who do not currently have access to natural gas.~~). It also includes providing incremental gas supply capacity to existing customers.

~~Distribution~~Rolling Project Portfolio: An accumulation of ~~all~~ the new business capital requisitions that are issued and approved ~~in the current~~for a 12 month~~. It~~ period. The rolling Profitability Index ("PI") is the cumulative PI data from the Rolling Project

[1] As filed in EB-2011-0210, Exhibit B1, Tab 3, Union Gas 2013 Cost of Service Application

portfolio. The rolling project portfolio includes all future customer attachments, revenues and costs on the basis of the life cycle of each project. It also includes a forecast of normalized reinforcement costs. It excludes those customers requiring only a service lateral from an existing main~~.~~

~~**Rolling Project Portfolio:** An accumulation of the new business capital requisitions from the past 12-months Distribution Project Portfolio. The rolling Profitability Index (PI) is the cumulative PI data from the Rolling Project portfolio.~~

Investment Portfolio: The costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching on existing mains). The Investment Portfolio includes a forecast of normalized reinforcement costs.

~~**Major Projects:** All new business projects with capital costs greater than $500,000.~~

Service Lateral: A gas pipeline connecting the company gas main to the customer's gas meter as measured from property line to meter.

Temporary Connection Surcharge (TCS): An economic contribution to financial feasibility of main extension projects made by customers who attach to the project through a temporary volumetric rate.

Temporary Expansion Surcharge (TES): An economic contribution to financial feasibility of community expansion projects by all the customers who attach to the system during the period in which it is in place through a temporary volumetric rate.

Minimum Size: The minimum pipeline design size required to supply gas to the affected customers without consideration of potential customer demand downstream from ~~this customer.~~ these customers.

Profitability Index ("PI"): A ratio of the net present value of cash inflows over the net present value of cash outflows resulting from a discounted cash flow analysis of a distribution new business project, or an accumulation of projects in the case of a portfolio.

Accountability

~~The Company~~Union manages separate ~~corporate distribution portfolios~~Investment Portfolios and Rolling Project Portfolios for Union North (Rate 01 and 10) and Union South (Rate M1 and M2) areas. Excluding Community Expansion Projects, the ~~Northern Operations area and the Southern Operations area. The rolling portfolio~~Rolling Project Portfolio PI for each area must remain above 1.0 and the Net Present Value ~~(~~(“NPV~~)~~”) must remain greater than $0 at all times.

The Director, Distribution Marketing is accountable for ensuring that the corporate ~~rolling~~Rolling Project Portfolio PI, excluding Community Expansion Projects, exceeds 1.0 on an ongoing basis.

Each district is accountable for ensuring that they maintain a district ~~rolling~~Rolling Project PI at or greater than a specified threshold. As a general rule the threshold is a PI of 1.0. However, at the discretion of the company, a district threshold may be set higher or lower for specified periods to balance the needs of customers and maintain the rolling PI for each operations area in excess of 1.0.

Project Acceptance Levels

~~The minimum qualifying project PI shall be 0.8 including any customer contributions. The company will manage the Investment Portfolio ensuring that the portfolio PI remains above 1.0 and the rate impact is acceptable.~~

~~Requests for exceptions to the minimum PI must be authorized by the Director, Distribution Marketing, and the Director, Distribution Operations.~~

~~A PI of 1.0~~A PI of 1.0 from a stage one economic feasibility analysis (discounted cash flow) is required in situations where there is no further growth anticipated in the surrounding area and /or a dedicated line is required (i.e. a large industrial customer or a customer requiring only a service).

Where the cost of proposed projects exceeds the capital available in a particular year or would result in failure to meet minimum portfolio performance (PI) targets, Union will proceed with the most profitable projects.

For single residential services being attached on existing main, an economic feasibility analysis is not required.

Acceptance Level Exceptions:

Subject to ability to manage minimum portfolio PI's as indicated above, projects can proceed with reduced PI levels. All requests for exceptions to the minimum project PI of 1.0 must be authorized by the Director, Distribution Marketing, and the Director, Distribution Operations prior to construction. Generally the following types of exceptions will be considered:

a) For Community Expansions projects that will provide first time natural gas access to a minimum of 50 potential customers in pre-existing homes and businesses, the minimum qualifying project PI shall be 0.4 including any customer and municipal contributions, provided that:
    i. Customer contributions include a minimum 4 year commitment to a Temporary Expansion Surcharge ("TES"), and
    ii. The municipality has agreed to make a contribution equivalent to the value of any incremental property taxes that would be generated from the project for a period of time that matches the term of the TES referenced above at minimum.
b) For Community Expansions projects that will provide first time natural gas system access to a minimum of 50 potential customers in pre-existing homes and businesses, a minimum qualifying project PI of 0.8 can be considered where conditions specified in section a above are not in place
c) For any other projects, if an alternative system design reduces investment required for the project, a reduced PI can be accepted. By example, a short main extension may be less costly for the Company than a high pressure road crossing service.

Collecting a Contribution

Projects that do not meet the minimum stage 1 economic criteria shall require that a contribution be collected from the customer(s).

The Company uses an Aid to ~~Construct~~Construction method to collect these contributions. This can be defined as a charge collected in advance of construction from new customers or other parties who have agreed to fund the shortfall in the economics.

a) The amount of ~~aid~~Aid to ~~construct~~Construction charged to the customer(s) will be based on the minimum size facilities to service that customer(s).

b) The customer(s) will have the option of paying the ~~aid~~Aid to ~~construct upfront~~Construction up front as a lump sum or have the amount financed at the company's finance rate.

For Community Expansion Projects, contributions will be collected from all customers serviced by the project through use of a Temporary Expansion Surcharge (TES), and municipal contributions can be collected by way of annual payments for the same term as the TES.

For other projects involving main extensions or commercial/industrial general service customer attachments requiring Aid to Construction in excess of $1,000 per customer, customers can elect to make a contribution by use of a Temporary Connection Surcharge (TCS)

Project Costs

a) When available, economic feasibility analysis shall use project specific data (costs, volumes, ~~and~~ customer attachments) based on survey data, historical practice, weather and local conditions to determine the costs, load and forecast.

b) When no specific data is available or the project is a minor project, district averages shall be used.

Service Laterals

a) The company shall provide at its cost up to 30 metres of service line to connect a residential customer.

b) Services over the length specified above shall require the prior agreement of the customer to pay an "excess charge" of $45.00 per metre. This charge reflects a company-wide average of summer versus winter pricing, open versus built up conditions and company versus contractor crew pricing. In all cases the customer/builder shall be advised in advance of this charge.

c) The PI analysis for ~~non-residential~~commercial and industrial services shall be individually calculated reflecting the site specific lateral length, pipeline sizing, costs, gas usage and margins. ~~Non-residential~~Commercial and Industrial customers shall be required to contribute Aid to ~~Construct~~Construction or the TCS if necessary to achieve a minimum PI of 1.0~~.~~, unless part of a Community Expansion Project. For services in Community Expansion projects, the minimum PI for commercial and industrial attachments will match that approved for the project until such time as the TES has been in place for 24 months.

d) The service lateral is measured from property line to meter.

e) The minimum requirement to qualify for residential service shall be attachment of a water heater or a primary heat source. Requests for service ~~without meeting~~where this condition is not satisfied shall be considered but will require a discounted cash flow analysis ~~with estimated costs~~ to be completed and any required customer contribution to be made in advance.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, Appendix J

a) Please provide a similar schedule showing the Revenue Requirement for the 5 initial Projects in the same format.

b) Please provide details of the Incremental Revenue calculation (line 12) for the 5 projects. Clarify if not shown, whether TES and ITE are included.

c) Please provide details of the Incremental Revenue calculation for the 30 projects (line 12). Clarify if not shown, whether TES and ITE are included.

d) Please list the Projects and Data for the 30 projects in the same format as Appendix D.

e) Please explain the criteria determining if a Provincial CIAC loan/grant is or is not required for each of the projects.

Response:

a) The revenue requirement for each of the four proposed Community Expansion Projects requested in this Application is provided at Exhibit A, Tab 1, Appendix F, Updated.[1]

A combined revenue requirement for the four proposed Community Expansion Projects requested in this Application is provided at Attachment 1.

b-c) A live excel spreadsheet in response to Exhibit B.LPMA.24 b) provides the incremental revenue calculation for the four projects for which Union is seeking approval. That file contains average use per customer, number of additions for each of the four projects from Exhibit A, Tab 2, Updated (using attachment rates specific to each project), and the resulting revenue and total volume. In general terms, the revenue forecast is customer additions times average revenue per customer. The live spreadsheet does not include the full 30 projects as it is premature to provide this level of detail. Projects other than the four referenced above have their attachment forecast based on 45% of market potential attaching during the first 10 years.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

Line 12 shown in Exhibit A, Tab 1, Appendix J, Updated excludes the TES and ITE.

d) Union will file the relevant data for each of the Projects at the time approval is sought for rate recovery of each of these Projects.

e) If the Projects meet the minimum proposed P.I. of 0.4 after including TES and ITE, no Aid-to-Construction would be required.

UNION GAS LIMITED
Revenue Requirement of the Milverton, Prince Township,
Chippewa's of Kettle and Stony Point First Nation and Lambton Shores and Delaware Nation of Moraviantown
Community Expansion Projects

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	9,244	418	166
2	Average Investment	3,020	9,133	9,209
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	4	17	33
4	Depreciation Expense (2)	125	254	262
5	Property Taxes	35	104	104
6	Total Operating Expenses	163	375	399
7	Required Return (5.77% x line 2) (3)	174	527	532
	Income Taxes:			
8	Income Taxes - Equity Return (4)	35	106	107
9	Income Taxes - Utility Timing Differences (5)	(55)	(107)	(99)
10	Total Income Taxes	(20)	(1)	8
11	Total Revenue Requirement (line 6 + line 7 + line 10)	317	902	938
12	Incremental Revenue (6)	24	110	203
13	Net Revenue Requirement (line 11 - line 12)	293	792	736

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$9.209 million x 64% x 4.0% = $0.236 million plus
$9.209 million x 36% x 8.93% = $0.296 million for a total of $0.532 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.

(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, Appendix K and
Exhibit A, Tab 1, Appendix L

a) Please provide a schedule with the Rate Class cost allocation for the initial 5 projects.

b) Please provide a schedule with the General Service Rate Impacts for the initial 5 projects.

Response:

a) Please see Attachment 1 for the rate class cost allocation of the 2018 project costs and the TES and ITE deferral credits for the four proposed Community Expansion Projects requested in this Application.[1]

b) Please see Attachment 2 for the 2018 general service bill impacts for the four proposed Community Expansion Projects requested in this Application. Attachment 2, p. 1 includes only the 2018 project costs and Attachment 2, p. 2 includes the 2018 project costs as well as the 2018 TES and ITE deferral credits.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED
2018 Cost Allocation of the Milverton, Prince Township,
Chippewa's of Kettle and Stony Point First Nation and Lambton Shores and Delaware Nation of Moraviantown
Community Expansion Projects

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	546	(293)	(28)	225
2	Rate M2	92	(49)	(5)	38
3	Rate M4	25	(13)	(1)	10
4	Rate M5	35	(19)	(1)	15
5	Rate M7	6	(3)	(0)	3
6	Rate M9	(0)	0	(0)	(0)
7	Rate M10	0	(0)	(0)	(0)
8	Rate T1	17	(9)	(1)	7
9	Rate T2	27	(14)	(4)	8
10	Rate T3	(0)	0	(0)	(0)
11	Subtotal - Union South	749	(402)	(42)	305
12	Excess Utility Space	(1)	0	(0)	(0)
13	Rate C1	(0)	0	(0)	(0)
14	Rate M12	(9)	5	(16)	(20)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(10)	5	(16)	(21)
18	Rate 01	50	(27)	(12)	11
19	Rate 10	21	(11)	(2)	8
20	Rate 20	50	(27)	(1)	22
21	Rate 100	67	(36)	(1)	30
22	Rate 25	12	(6)	(0)	5
23	Subtotal - Union North	200	(107)	(17)	76
24	In-franchise	948	(509)	(59)	380
25	Ex-franchise	(10)	5	(16)	(21)
26	Total	938	(504)	(75)	360

Notes:
(1) 2018 project costs associated with four potential Community Expansion Projects, as per Exhibit B.EnergyProbe.19, Attachment 1, column (c).
(2) TES credit allocated to rate classes in proportion to column (a).
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED
2018 General Service Bill Impacts of the Milverton, Prince Township,
Chippewa's of Kettle and Stony Point First Nation and Lambton Shores and Delaware Nation of Moraviantown
Community Expansion Projects
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.67	0.35	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.31	(0.00)	
5	Total Delivery Charge	349.64	349.98	0.35	0.1%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.38	0.35	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.35	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.35	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	196.13	0.86	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	448.13	0.86	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	(0.00)	
17	Storage Services	95.59	95.58	(0.00)	
18	Subtotal	268.02	268.02	(0.00)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.00)	
21	Total Bill (line 13 + line 18)	989.55	990.41	0.85	0.1%
22	Impacts for Customer Notices - Sales (line 19)			0.85	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			0.85	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts of the Milverton, Prince Township,
Chippewa's of Kettle and Stony Point First Nation and Lambton Shores and Delaware Nation of Moraviantown
Community Expansion Projects Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.67	0.35	
3	Delivery Price Adjustment	-	(0.24)	(0.24)	
4	Storage Services	16.32	16.31	(0.00)	
5	Total Delivery Charge	349.64	349.74	0.11	0.0%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.14	0.11	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.11	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.11	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	196.13	0.86	
14	Delivery Price Adjustment	-	(0.09)	(0.09)	
15	Total Delivery Charge	447.28	448.04	0.77	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	(0.00)	
17	Storage Services	95.59	95.58	(0.00)	
18	Subtotal	268.02	268.02	(0.00)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.00)	
21	Total Bill (line 13 + line 18)	989.55	990.31	0.76	0.1%
22	Impacts for Customer Notices - Sales (line 19)			0.76	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			0.76	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 1, Appendix M

a) Please provide a schedule with the Rate Class cost allocation including TES and ITE for the initial 5 projects.

b) Please provide a schedule with the General Service Rate Impacts including TES and ITE for the initial 5 projects.

Response:

a) Please see Exhibit B.Energy Probe.20 a).

b) Please see Exhibit B.Energy Probe.20 b).

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("Energy Probe")

Reference: Exhibit A, Tab 2, Section A, Kettle Point Project
Exhibit A, Tab 2, Section B, Milverton Project
Exhibit A, Tab 2, Section C, Moraviantown Project
Exhibit A, Tab 2, Section D, Prince Township Project
Exhibit A, Tab 2, Section E, Walpole Project

a) Please provide a Summary Workbook and schedules with the details of each project including:
   - In service date
   - Customer attachments
   - Capital Cost
   - Natural NPV and PI
   - NPV and PI with TES and ITE.
   - TES period
   - Amount of TES contributions
   - Amount of ITE contributions
   - Provincial Infrastructure CIAC
   - Revenue forecast for 10 years and lifetime 40 years

b) Please reconcile the above to the data in respective Sections A-D and E and to Exhibit A, Tab 1, Appendix D.

c) Please provide an estimate for each project of the additional revenue/CIAC required to achieve a PI of 0.8. List assumptions used to prepare the estimates.

Response:

a) The majority of the data requested is filed in evidence. Please refer to the Schedules provided in Exhibit A, Tab 2[1].

In-service Date	DCF parameter schedule
Customer attachments	Customer attachment schedule
Capital cost	Capital cost schedule
NPV and PI with TES, ITE	DCF Schedule

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

TES and ITE Term	DCF parameter schedule
Amount of TES, ITE	Lines 5, 6 DCF Schedule
CIAC	Zero as filed
Revenue Forecast	Line 1 DCF Schedule

The table below provides the data not reflected in the evidence sections:

Project	"Natural PI" PI prior to TES, ITE	"Natural NPV" $ 000's NPV Prior to TES, ITE
Lambton Shores/Kettle Point	0.44	($977)
Milverton	0.32	($3,137)
Moraviantown	0.35	($319)
Prince Township	0.38	($1,641)

b) Exhibit A, Tab 2, Appendix D provides the P.I. for Lambton Shores/Kettle Point as 0.42 which is a typographical error. The correct figure is 0.44.

c) Please see the response at Exhibit B.LPMA.14 c).

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Preamble: In its Application of July 23 to the Ontario Energy Board (EB-2015-0179) Union Gas applies for certain Orders to provide the necessary financial assistance to allow Union to construct facilities that will extend natural gas into markets which are otherwise uneconomical.

Union is asking for the following Orders:

a) An Order allowing a Temporary Expansion Surcharge (TES) of $.23 per m3.

b) An Order allowing Union to charge Municipalities an Incremental Tax Equivalent (ITE) equal to the forecasted property tax payments Union will be making.

c) An Order establishing the term for the TES and ITE.

d) An Order allowing Union to include in rate base the total cost of a capital project when the project goes into service.

e) An Order allowing automatic recover in rates each year of any deficiency between the forecasted net revenue requirement and the actual revenue requirement achieved. (This money is to be funded by the TES and placed in deferral account to be cleared annually)

f) An Order allowing a Temporary Connection Charge (TCS) to be charged to all existing customers of approximately $2 per month or $24 per year over the multiyear expansion program

If the Board refuses to grant one or more of these Orders what are the implications for the other Orders?

Response:

Union will determine and assess any implications that result from the Board's Decision after the Decision is issued.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: TES

Preamble: Union proposes a TES rate of $.23 per m3 for new customers in new expansion areas. To calculate this amount Union assumes that the average residential customer will save $1600 per year by converting to natural gas. Union also estimates that the one-time cost of conversion is approximately $4000. That means that after paying the conversion costs the customer saves $1932 over 3.75 years or $515 per year. Union assumes that the average annual consumption is 2200 m3. Accordingly the $ 515 equals $.23 per M3. Union therefore argues that in the first 3.75 years the total savings will be paid to the utility in the form of a TES. That is the customer is neutral. The Conversion cost is offset by the savings. After the 3.75 years the customer saves $1600 per year.

a) Is this rate dependent on the achievement of a specific conversion rate?

b) If so what is that rate?

c) If Union fails to achieve that rate what are the implications for the TES rate proposed?

Response:

a) The savings figures as posed in the question are incorrect. The expansion area customer only begins saving the entire $1,600 after the TES term has expired. During the TES term an average residential customer will save $1,094 ($1,600 – TES of $506) each year until the term expires.

   The TES rate was determined based on the payback period analysis, and is independent of the conversion rate. The TES rate will not be affected by the rate of conversions.

b) Please see a) above.

c) Please see a) above.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: TES

Preamble: The government of Ontario in establishing the natural gas expansion project has established a grant program of $ 20 million and a loan fund of $200 million. The government is not specific as to the purpose to which these funds should be directed.

Union makes no submission with respect to the use of government funds except to say that they will be used to reduce any capital costs.

a) Does Union intend to apply under the government grant program?

b) If so, what will Union's request be?

c) If the government grants that request what are the implications for this application?

d) If not, why not?

Response:

Union notes that the grant program announced by the Province is $30 million as opposed to the $20 million referenced in the Preamble above.

a) While the details of the Natural Gas Economic Development Grants are currently unknown, Union intends to assist potential expansion communities in need of Aid-to-Construction (as outlined in Exhibit A, Tab 1, Appendix D), in applying for this funding.

   This funding will allow northern and rural communities beyond the 30 potential projects identified in this Application (Exhibit A, Tab 1, Appendix D, rows 1 to 34 excluding rows 16, 18 and 30) to gain access to natural gas. Please see the response at Exhibit B.CCC.16.

b) Union would encourage Municipalities that meet whatever criteria are established for the funding to apply for it to the extent that Aid-to-Construction is required, to enable projects to serve their communities.

c) The implications are that natural gas could be extended to more than the 30 projects that could be enabled as a result of Union's Application.

d) Please see the response to a) above.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: ITE

Preamble: Union has asked the Board to allow Union to charge the Municipalities an annual fee which would be equal to the forecasted property taxes Union would pay during the TES term The Municipality must agree to this prior to construction. The municipality would only pay the ITE on projects with a PI of less than .8.

a) What authority does the Board have to issue the requested Orders?

b) If the municipality refuses what adjustment will Union make to other rates?

c) What authority does the Board have to include in rates an amount that reflects the refusal by municipality to waive property taxes?

Response:

a) The Board has the authority to set rates under the OEB Act[1], Section 36(2). Union is seeking approval of a mechanism to collect municipal contributions, not a specific amount. The ITE contributions collected will be captured in the proposed Community Expansion Contributions Deferral Account along with the TES contributions. The intent of the deferral account is to allocate the ITE revenues to ratepayers to reduce the cross-subsidization of the capital costs.

b) If the municipality refuses to pay the ITE, the related project will not be eligible for a reduced P.I. and Union would not propose to construct facilities unless the project could meet a P.I. of at least 0.8 or higher. This approach could result in an extended TES term for the potential customers in that expansion community. For example, if a community only requires a TES and ITE term of six years to reach the minimum P.I. of 0.4, and the municipality refuses to agree to the ITE, then it is possible that extending the TES from six years towards the proposed maximum term of 10 years might still make the project feasible at a P.I. of 0.8.

If an extension of the TES term will not make the Project viable at a P.I. of 0.8 or higher, any remaining gap would have to be funded through an Aid-to-Construction. Requiring a higher minimum P.I. (0.8 or higher) in circumstances where the Municipality is not able to pay the ITE

[1] Ontario Energy Board Act, 1998, Part III, Gas Regulation, Section 36(2).

would reduce the revenue deficiency resulting from the Project, in comparison to the revenue deficiency that would exist if the Project was undertaken at a P.I. of 0.8.

c) This situation would not occur based on Union’s response to b) above.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: TES Term

Preamble: Union proposes that the maximum TES term be 10 years. The term is the time it takes project to reach PI of 1 or to breakeven .The term can be less than ten years for more profitable projects. The term ends at year 10 for every customer regardless of when the customer connected.

What action will Union take if none of the projects reach a PI of 1 in less than 10 years?

Response:

The question appears to be based on an incorrect interpretation of Union's proposal. The term is not the time it takes a project to reach a P.I. of 1.0 or to break even. If that were the case, Union would not be applying for exemption from the minimum P.I. requirements established in E.B.O. 188.

To clarify, Union is proposing to complete Projects that may have a P.I. as low as 0.4, after including the effects of the TES, ITE, and any necessary Aid-to-Construction in the economic feasibility analysis. These Projects are expected to meet this P.I. level over the economic life of the assets being installed. As such, Union does not expect these Projects to reach a P.I. of 1.0.

However, in the event that one of these Community Expansion Projects reached a P.I. of 1.0, the unexpected benefits would be credited to ratepayers through the Community Expansion Contribution Deferral Account disposition process, as outlined in Exhibit A, Tab 1, p. 33.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: TES Term

Preamble: Union proposes to adjust rates annually to recover any shortfall in the actual net revenue received compared to the net revenue requirement allowed and to fund that payment by the TES charge.

a) Has Union estimated the expected revenue shortfall?

b) If so, how much is it and what projects does it relate to?

Response:

a) The TES will not be used to fund any shortfall resulting from forecasted versus actual revenues. It will be used solely to support making the Projects economically feasible, and once the term is set for a specific Project it will not be adjusted.

b) Please see the response to a) above.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: TCS

Preamble: Union proposes that all customers should make a contribution to the natural express gas expansion program. This is called the temporary connection surcharge or TCS. Existing customers would pay approximate two dollars per month over the multiyear expansion program. Union proposes to complete approximately 30 projects and provide natural gas service to approximately 20,000 homes and businesses including seven first nations at a total cost of $150 million.

a) What percentage of the total cost of $150 million will be funded by the TCS?

b) Will the rate be adjusted if Union elects not to proceed with all 30 projects?

c) Does Enbridge intend to implement a similar TCS charge in its territories?

d) If Enbridge elects not to implement a similar program what are the implications for the Board in terms of discrimination between ratepayers?

e) Will utilities other than Union that have before the board applications under the gas expansion program have access to the funds raised from Union's existing customers through the TCS charge?

f) If so, how will the Board allocate the funds between utilities?

g) How will Union allocate the funds raised through the TCS charge between projects?

h) What action does Union intend to take if specific customers refuse to pay the TCS charge?

Response:

The question appears to be based on a misinterpretation of Union's proposal. The TCS rate has not been proposed at $2.00/month and is not related in any way to funding the 30 potential Projects.

a) The TCS will not be used to fund any portion of the proposed Community Expansion Projects. Please see the response at Exhibit B.Energy Probe.17 a).

b) Please see the response to a) above.

c) Union is not aware of Enbridge's intention with respect to a TCS.

d) Please see the response to c) above.

e) No.

f) Please see the response to e) above.

g) Please see the response to a) above. The TCS charge supports the economic feasibility of only the Project for which it is required.

h) If a customer refuses to pay a TCS in order to enable their connection to the system, their only other option is to pay required Aid-to-Construction. Otherwise their connection would be uneconomic and Union would not proceed.

UNION GAS LIMITED

Answer to Interrogatory from
EPCOR Utilities Inc. ("EPCOR")

Reference: The Capital Pass Through

Preamble: Union proposes that the Union be allowed to include in rate base the Project capital when it becomes used and useful and in service. Union indicates it is necessary to avoid the problem that inclusion in rate base may be delayed if utilities are in a multiyear rate plan.

a) Will this adjustment be made in an annual application to the Board?

b) If not, what process does Union intend to follow?

Response:

a) Subject to the Board's approval of Union's Community Expansion Project proposal, Union plans to pass through into rates the revenue requirement of the four[1] projects identified in this Application. Specifically, these Projects are Milverton, Prince Township, Chippewas of Kettle and Stony Point First Nation/Lambton Shores and Delaware Nation of Moraviantown. Union will file a Leave-to-Construct Application or an Application seeking approval including the forecast net revenue requirement for subsequent Projects prior to including any additional Projects in rates.

   Union will include the approved Project costs in rates in its annual rate filing in accordance with the Board-approved 2014-2018 Incentive Regulation Application in the year following the approval of the specific Projects.

   Union will apply to dispose of balances in the proposed Community Expansion Project Deferral Account and Community Expansion Contribution Deferral Account as part of Union's annual non-commodity deferral account disposition proceeding.

b) Please see the response to a) above.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section B, Schedules 5 and 6

Preamble: With more than half of the estimated cost of the Milverton project being the NPS 4 Steel transmission line, we are interested in alternatives considered to extend service to this and other remote communities.

Has Union estimated the cost of providing interim service using Compressed Natural Gas ("CNG") trucked from the existing source near Sebringville to the proposed Gate Station in Milverton?

a) If not, why not?

   i) Why would Union not consider developing the capability of creating "receipt and delivery" stations, potentially skid mounted, that could serve as interim transmission systems for these remote communities until the distribution system is built out based upon market demand?

b) If so, please update Schedules 5 and 6 to reflect the impact of interim CNG delivery system for the first:

   i) 5 years
   ii) 10 years

Response:

a-b) Union has conducted a review of compressed natural gas ("CNG") and liquefied natural gas ("LNG") alternatives and found that while they may represent reduced up-front investment requirements in comparison to pipeline supplied projects, they may be more costly over the life of the assets, may offer less reliability than pipeline supply to communities, and will require a long lead time to work through a number of regulatory considerations. Although CNG or LNG may present viable opportunities to provide natural gas to more remote communities, traditional pipeline supply is favoured where the economics can be made feasible. For this reason Union has focused its proposal on potential pipeline supplied communities.

Union will continue to evaluate CNG and LNG options as the technology evolves in order to ensure the most cost-effective way to serve each community, provided that a similar level of reliability of service can be maintained.

Specifically with reference to the Milverton project, Union has explored a CNG supply model with the following findings:

Estimated One Time Capital

Item	Capital Cost (millions)
CNG Compressor[1]	$3.5 to $5.4
4 CNG Trailers @ $0.35 million	$1.4
CNG Decanting site	$1.4
Distribution mains, services, and metering equipment	$2.1
Total	**$8.3 to $10.2**

Estimated Incremental Annual Operating Costs

Item	Annual Cost (thousands)
Electricity	$39
Maintenance	$29
Personnel	$200
CNG Transport	$72
Total	**$341**

The capital costs for a CNG alternative, even at the lower range of $8.3 million as provided above, exceed the cost of a traditional pipeline supplied project of $4.9 million. In addition to the higher capital costs, the annual operating costs of $341,000 would equate to over $400 per attached customer per year. For these reason Union has not updated Schedules 5 and 6 as requested.

[1] CNG Compressor Costs will vary with required fill time; 3 hour and 10 hour fill options are included above. Annual transport costs would increase above those shown with the smaller (longer fill time) compressor.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 56

a) Please explain to which "customers" the surcharge revenue would be disposed of annually.

b) Please explain why the surcharge revenue would not be considered an aid to construction and used to reduce the capital cost of the projects included in rate base.

c) If the surcharge revenue were treated as an aid to construction, thereby reducing rate base and associated costs with the projects, what would be the impact on the overall costs of the projects proposed in this application? Please provide all assumptions and calculations.

Response:

a) The surcharge revenue would be disposed to all current ratepayers in the rate classes listed in Exhibit 1, Tab 1, Appendix K, at the time of its disposal.

b) A contribution in Aid-to-Construction ("CIAC") is an amount collected and recorded at the time of construction. The proposed Temporary Expansion Surcharge ("TES") is a rate for service charged to customers in new communities as service is provided. Amounts earned as a result of providing service are accounted for as revenue consistent with generally accepted accounting principles ("GAAP"). The recovery of amounts from the municipality while not based directly on service provided are proposed to be recovered over time and will also be recorded as revenue. Treating some portion of the recovery of incremental costs as revenue and other amounts as a reduction in plant is unnecessarily complicated.

   It is Union's position that the proposal to treat the amounts recovered from customers and municipalities as revenue better reflects the economic reality, is less complicated than the treatment as CIAC, and results in an improvement of the P.I. using the E.B.O. 188 financial methodology. Each of these is discussed below.

   Treatment as revenue reflects economic reality of the transaction:

   - Under Union's proposal the incremental cost of expansion is rolled into rate base reflecting the real incremental cost incurred to provide service. Under the CIAC option, the incremental cost to construct reflected in rate base is adjusted down by the amount of the CIAC and the resulting average cost of service understates the actual average cost. In the CIAC case, the financial barrier for any pipeline addition whether it is for a new community, or for a new housing subdivision within an existing serviced area, continues to grow as actual costs increase while the revenue test, based on historical costs, does not.

- The revenue surcharge (TES/ITE) paid by the new Community Expansion customers offsets a portion of the additional rate increase attributed to the expansion. This is a hybrid approach between rolled in tolling, where all customers pay the same rate, and an incremental tolling approach, where incremental costs are the basis of the rate. The hybrid approach is reasonable in this limited circumstance as a means to respond to the Province's desire and the Board's request for proposals.

Reduced complexity

- Union's proposal is to:
  - Record capital as plant included in rate base;
  - Record billing of surcharge to customers as revenue; and,
  - Adjust rates to existing customers to recover any revenue deficiency (the difference between the additional revenue requirement and the revenue from the surcharge).

- The CIAC option would require additional process:
  - Record aid as a reduction to plant and a receivable up front (GAAP requirement);
  - Request Board approval to include CIAC receivable in rate base (to earn a return on investment);
  - Record an adjustment to revenue and receivable for the amount of CIAC collected. This would be a continuous monthly process as the TES/ITE is collected; and,
  - Request Board approval to include any uncollected CIAC receivable at the end of term in plant (regulatory asset).

P.I. Implications

- Under Union's proposal the P.I. is higher than it would be under a different proposal whereby a CIAC is collected. Milverton is the largest of the four projects Union is seeking approval for in this Application.[1] The P.I. for Milverton is 0.57 as proposed and would be 0.38 under a CIAC proposal.

c) The TES and ITE treated as revenue is a foundation of Union's proposal and if treated as an aid, an alternative financial proposal would be required.

   Treatment as an aid would slightly decrease the 40 year assessment of the revenue requirement relative to Union's proposal although this would not occur until 20 plus years after in service.

[1] The Walpole Island First Nations Project, is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

To illustrate Union's proposal, Union has prepared an example using Milverton (Exhibit A, Tab 2, Section 2). Attachment 1 is the revenue requirement for Milverton over a 40 year term under Union's proposal and an alternative proposal whereby a CIAC mechanism is created and applied. Both cases use the same capital costs, attachments, use per customers, etc. The only difference is the TES and ITE treatment.

Milverton is based on the four year minimum term for the TES and ITE. Figure 1 below is a graph showing the annual revenue requirement as proposed and an alternative proposal where the equivalent amount is collected as an aid.

As shown in Figure 1, Union's proposal reduces the revenue requirement over the term the TES/ITE is in place. In the Milverton example the term is four years, but for other projects the term can be as long as 10 years. Exhibit A, Tab 1, Appendix D lists the terms of the TES/ITE for other potential projects. When the TES/ITE term expires the revenue collection from the expansion customers served by that Project ceases and the annual revenue requirement relative to an aid reverses.

Figure 2 illustrates the NPV of the cumulative revenue requirement under both methods. The advantage of Union's proposal stays in place for 23 years before the cross over point. The significant early year impacts reduce the revenue requirement that would be paid by ratepayers. Other projects would have similar patterns. Since Milverton has a 4 year TES/ITE term, examples for other projects would have a cross over point sometime after year 23 because the TES/ITE revenue stream would be in place for terms as long as 10 years.

Figure 1: Revenue Requirement Annually

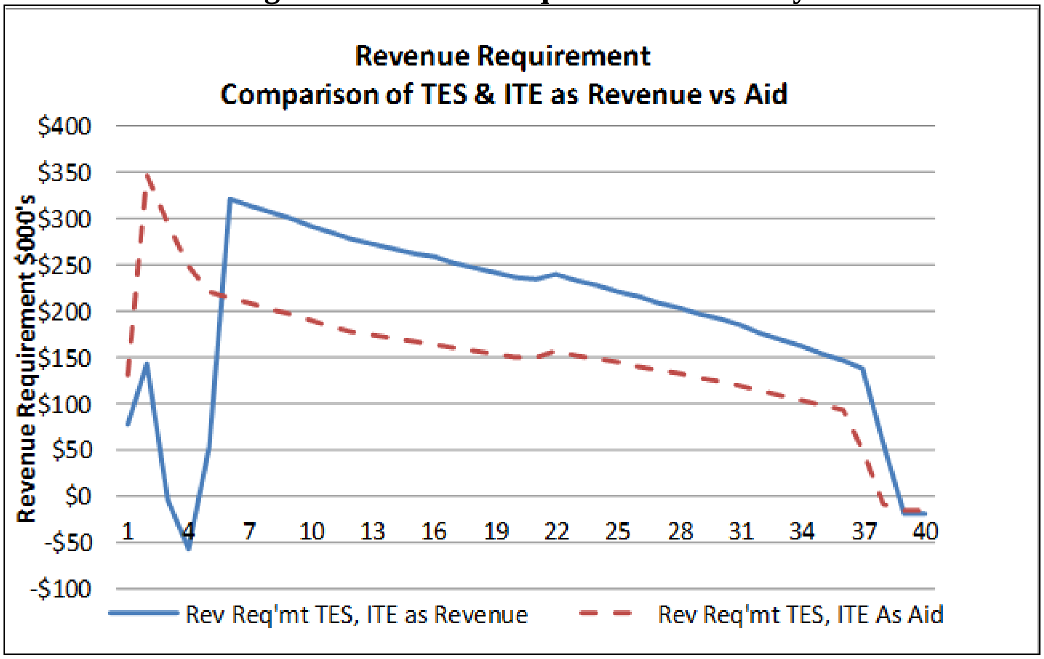
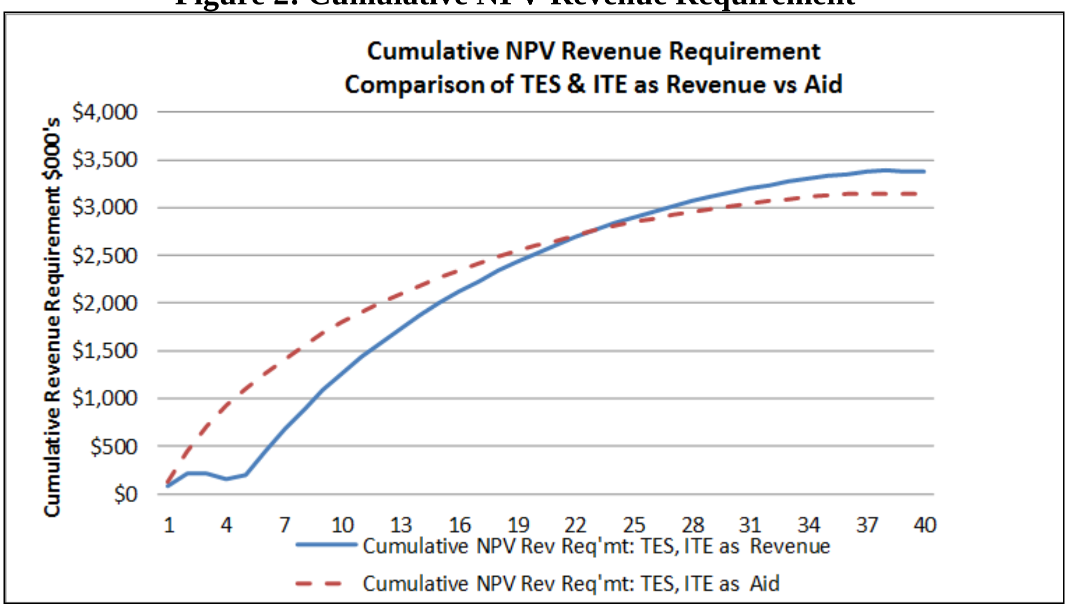


Figure 2: Cumulative NPV Revenue Requirement



Notes

Figure:

- Year 1 is based on a September 1st in service (four months) and Year 2 and thereafter are 12 months. As is normal the partial year revenue requirement skews the ongoing pattern.

Readers should be looking at the relative starting point of Year 2 for full year impact of each line.

- The line representing TES/ITE as revenue rises at Year 5, and the dashed line showing the TES/ITE as aid flattens at the same time because the term of the TES and ITE expires after 4 years for Milverton.
- There is a change in slope at Year 21. This is the result of the revenue assumption for the commercial/industrial customers which are based on a revenue term of 20 years. The revenue for the first year commercial attachment drops off at Year 21 and the last commercial attachment in Year 31.

The change in slope near the end of the line (Year 38) is the result of a reduction in depreciation expense as a portion of the asset becomes fully depreciated.

The data used to plot the graphs can be found in Attachment 1, lines 3, 4, 9 and 11.
The data in Attachment 1 is drawn from Attachment 2 (TES, ITE as Revenue), and Attachment 3 (TES, ITE as aid). Attachments 2 and 3 are the revenue requirements by year under each alternative.

Milverton: Preferred Design
Comparion of TES, ITE as Revenue or Aid

Line	($000's CDN)		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
			1	2	3	4	5	6	7	8	9	10	11	12
1	Total TES, ITE		176	336	385	411	-	-	-	-	-	-	-	-
2	Cummulative TES, ITE		176	512	897	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308
	Revenue Requirement													
3	Rev Req'mt TES, ITE as Revenue		78	143	(3)	(58)	54	321	315	307	300	292	284	278
4	Rev Req'mt TES, ITE As Aid		132	348	296	249	220	214	209	202	196	190	183	178
5	Difference	diff	(53)	(204)	(298)	(307)	(166)	107	106	105	104	102	101	100
	Discounted Cummulative Rev Req Calculation													
6	Discount Rate	5.10%												
7	Mid Period Factor	0.50	0.9754	0.9281	0.8831	0.8402	0.7994	0.7607	0.7237	0.6886	0.6552	0.6234	0.5932	0.5644
8	Discounted Rev Req'mt TES, ITE as Revenue		77	133	(2)	(48)	43	244	228	212	196	182	169	157
9	Cummulative NPV Rev Req'mt: TES, ITE as Revenue		77	209	207	159	202	446	674	886	1,082	1,264	1,433	1,590
10	Discounted Rev Req'mt TES, ITE As Aid		128	323	261	210	176	163	151	139	129	118	109	100
11	Cummulative NPV Rev Req'mt: TES, ITE as Aid		128	451	712	922	1,098	1,261	1,412	1,551	1,680	1,798	1,907	2,007
12	Difference Revenue vs Aid		(52)	(242)	(505)	(763)	(896)	(814)	(738)	(666)	(598)	(534)	(474)	(418)
13	Cross over Year	23												
	Average Investment													
14	Ave Investment TES, ITE as Revenue		1,391	4,203	4,231	4,184	4,121	4,052	3,987	3,919	3,851	3,777	3,681	3,549
15	Ave Investment TES, ITE As Aid		1,334	3,923	3,612	3,196	2,891	2,858	2,828	2,796	2,763	2,725	2,664	2,568
16	Difference		57	281	619	988	1,229	1,194	1,159	1,123	1,088	1,052	1,017	981

Milverton: Preferred Design
Comparion of TES, ITE as Revenue or Aid

Line	($000's CDN)		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
			13	14	15	16	17	18	19	20	21	22	23	24	25	26
1	Total TES, ITE		-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Cummulative TES, ITE		1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308
	Revenue Requirement															
3	Rev Req'mt TES, ITE as Revenue		273	268	263	258	253	247	242	236	236	240	233	227	221	215
4	Rev Req'mt TES, ITE As Aid		175	172	168	165	161	157	153	149	151	157	152	149	145	140
5	Difference	diff	98	97	95	93	92	90	88	86	85	83	81	79	77	75
	Discounted Cummulative Rev Req Calculation															
6	Discount Rate	5.10%														
7	Mid Period Factor	0.50	0.5370	0.5109	0.4861	0.4625	0.4401	0.4187	0.3984	0.3791	0.3607	0.3432	0.3265	0.3107	0.2956	0.2813
8	Discounted Rev Req'mt TES, ITE as Revenue		147	137	128	119	111	104	96	89	85	82	76	71	65	61
9	Cummulative NPV Rev Req'mt: TES, ITE as Revenue		1,736	1,873	2,001	2,121	2,232	2,336	2,432	2,521	2,606	2,689	2,765	2,836	2,901	2,962
10	Discounted Rev Req'mt TES, ITE As Aid		94	88	82	76	71	66	61	57	54	54	50	46	43	40
11	Cummulative NPV Rev Req'mt: TES, ITE as Aid		2,101	2,189	2,271	2,347	2,418	2,484	2,545	2,601	2,656	2,710	2,760	2,806	2,848	2,888
12	Difference Revenue vs Aid		(365)	(315)	(269)	(226)	(186)	(148)	(113)	(80)	(49)	(21)	5	30	53	74
13	Cross over Year	23														
	Average Investment															
14	Ave Investment TES, ITE as Revenue		3,418	3,286	3,155	3,023	2,892	2,760	2,628	2,497	2,365	2,233	2,101	1,970	1,838	1,707
15	Ave Investment TES, ITE As Aid		2,472	2,376	2,280	2,184	2,087	1,991	1,895	1,799	1,703	1,606	1,510	1,414	1,318	1,221
16	Difference		946	910	875	840	804	769	733	698	662	627	591	556	521	485

Milverton: Preferred Design
Comparion of TES, ITE as Revenue or Aid

Line	($000's CDN)		2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
			27	28	29	30	31	32	33	34	35	36	37	38	39	40
1	Total TES, ITE		-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Cummulative TES, ITE		1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308	1,308
	Revenue Requirement															
3	Rev Req'mt TES, ITE as Revenue		209	203	197	191	184	177	169	162	154	146	139	56	(18)	(19)
4	Rev Req'mt TES, ITE As Aid		137	133	129	124	120	114	109	104	98	93	50	(9)	(15)	(16)
5	Difference	diff	73	71	69	67	64	62	60	58	56	54	89	65	(3)	(3)
	Discounted Cummulative Rev Req Calculation															
6	Discount Rate	5.10%														
7	Mid Period Factor	0.50	0.2676	0.2546	0.2423	0.2305	0.2193	0.2087	0.1986	0.1889	0.1798	0.1710	0.1627	0.1548	0.1473	0.1402
8	Discounted Rev Req'mt TES, ITE as Revenue		56	52	48	44	40	37	34	31	28	25	23	9	(3)	(3)
9	Cummulative NPV Rev Req'mt: TES, ITE as Revenue		3,018	3,069	3,117	3,161	3,202	3,238	3,272	3,303	3,330	3,355	3,378	3,387	3,384	3,381
10	Discounted Rev Req'mt TES, ITE As Aid		37	34	31	29	26	24	22	20	18	16	8	(1)	(2)	(2)
11	Cummulative NPV Rev Req'mt: TES, ITE as Aid		2,925	2,958	2,989	3,018	3,044	3,068	3,090	3,109	3,127	3,143	3,151	3,150	3,147	3,145
12	Difference Revenue vs Aid		93	111	128	143	157	170	182	193	203	212	227	237	236	236
13	Cross over Year	23														
	Average Investment															
14	Ave Investment TES, ITE as Revenue		1,575	1,443	1,312	1,180	1,048	917	785	654	522	390	259	155	105	82
15	Ave Investment TES, ITE As Aid		1,125	1,029	933	837	741	644	548	452	356	260	178	130	105	82
16	Difference		450	414	379	343	308	273	237	202	166	131	81	25	(0)	(0)

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion Project
TES, ITE as Revenue

Line No.	Particulars ($000's)	1 2016 (a)	2 2017 (b)	3 2018 (c)	4 2019 (d)	5 2020 (e)	6 2021 (f)	7 2022 (g)	8 2023 (h)	9 2024 (i)	10 2025 (j)	11 2026 (k)	12 2027 (l)	13 2028 (m)	14 2029 (n)
	Rate Base Investment														
1	Capital Expenditures	4,259	179	80	63	52	61	59	61	58	53	0	0	0	0
2	Average Investment	1,391	4,203	4,231	4,184	4,121	4,052	3,987	3,919	3,851	3,777	3,681	3,549	3,418	3,286
	Revenue Requirement Calculation:														
	Operating Expenses:														
3	Operating and Maintenance Expenses	1	7	14	18	21	24	27	30	33	36	39	40	41	42
4	Depreciation Expense	57	117	120	122	124	125	127	128	130	131	132	132	132	132
5	Property Taxes	16	49	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	75	173	183	189	194	198	202	207	211	216	219	221	222	223
7	Required Return (5.77% x line 2)	80	243	244	241	238	234	230	226	222	218	212	205	197	190
	Income Taxes:														
8	Income Taxes - Equity Return	16	49	49	48	48	47	46	45	45	44	43	41	40	38
9	Income Taxes - Utility Timing Differences	(25)	(49)	(45)	(41)	(36)	(32)	(28)	(25)	(21)	(18)	(14)	(11)	(7)	(4)
10	Total Income Taxes	(9)	(0)	4	8	11	15	18	21	23	26	28	31	32	34
11	Total Revenue Requirement (line 6 + line 7 + line 1(	146	415	431	438	443	446	450	454	457	460	460	456	452	447
12	Incremental Revenue	9	43	81	102	115	125	135	146	157	168	176	179	179	179
13	TES and ITE	59	229	353	394	274	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	68	272	434	496	388	125	135	146	157	168	176	179	179	179
15	Net Revenue Requirement (line 11 - line 14)	78	143	(3)	(58)	54	321	315	307	300	292	284	278	273	268

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion Proj(
TES, ITE as Revenue

Line No.	Particulars ($000's)	15 2030 (o)	16 2031 (p)	17 2032 (q)	18 2033 (r)	19 2034 (s)	20 2035 (t)	21 2036 (u)	22 2037 (v)	23 2038 (w)	24 2039 (x)	25 2040 (y)	26 2041 (z)	27 2042 (aa)	28 2043 (ab)
	Rate Base Investment														
1	Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Average Investment	3,155	3,023	2,892	2,760	2,628	2,497	2,365	2,233	2,101	1,970	1,838	1,707	1,575	1,443
	Revenue Requirement Calculation:														
	Operating Expenses:														
3	Operating and Maintenance Expenses	43	45	46	47	48	49	48	44	41	41	41	41	42	42
4	Depreciation Expense	132	132	132	132	132	132	132	132	132	132	132	132	132	132
5	Property Taxes	49	49	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	224	225	227	228	229	230	229	225	222	222	222	222	223	223
7	Required Return (5.77% x line 2)	182	174	167	159	152	144	136	129	121	114	106	98	91	83
	Income Taxes:														
8	Income Taxes - Equity Return	37	35	33	32	30	29	27	26	24	23	21	20	18	17
9	Income Taxes - Utility Timing Differences	(1)	2	5	7	10	12	14	16	18	20	22	23	25	26
10	Total Income Taxes	36	37	38	39	40	41	42	42	42	43	43	43	43	43
11	Total Revenue Requirement (line 6 + line 7 + line 1(	442	437	432	426	421	415	407	396	385	378	371	364	356	349
12	Incremental Revenue	179	179	179	179	179	179	172	156	152	151	149	148	147	146
13	TES and ITE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	179	179	179	179	179	179	172	156	152	151	149	148	147	146
15	Net Revenue Requirement (line 11 - line 14)	263	258	253	247	242	236	236	240	233	227	221	215	209	203

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion Proj
TES, ITE as Revenue

Line No.	Particulars ($000's)	29 2044 (ac)	30 2045 (ad)	31 2046 (ae)	32 2047 (af)	33 2048 (ag)	34 2049 (ah)	35 2050 (ai)	36 2051 (aj)	37 2052 (ak)	38 2053 (al)	39 2054 (am)	40 2055 (an)
	Rate Base Investment												
1	Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0
2	Average Investment	1,312	1,180	1,048	917	785	654	522	390	259	155	105	82
	Revenue Requirement Calculation:												
	Operating Expenses:												
3	Operating and Maintenance Expenses	42	43	43	44	45	45	46	47	47	47	47	47
4	Depreciation Expense	132	132	132	132	132	132	132	132	132	76	23	23
5	Property Taxes	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	223	224	224	225	226	226	227	227	228	172	119	119
7	Required Return (5.77% x line 2)	76	68	60	53	45	38	30	23	15	9	6	5
	Income Taxes:												
8	Income Taxes - Equity Return	15	14	12	11	9	8	6	5	3	2	1	1
9	Income Taxes - Utility Timing Differences	27	28	30	31	32	33	33	34	35	16	(3)	(2)
10	Total Income Taxes	42	42	42	41	41	40	40	39	38	18	(1)	(1)
11	Total Revenue Requirement (line 6 + line 7 + line 1(	341	334	326	319	312	304	296	289	281	199	124	123
12	Incremental Revenue	144	143	142	142	142	142	142	142	142	142	142	142
13	TES and ITE	-	-	-	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	144	143	142	142	142	142	142	142	142	142	142	142
15	Net Revenue Requirement (line 11 - line 14)	197	191	184	177	169	162	154	146	139	56	(18)	(19)

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion Project
TES, ITE as Aid

Line No.	Particulars ($000's)	1 2016 (a)	2 2017 (b)	3 2018 (c)	4 2019 (d)	5 2020 (e)	6 2021 (f)	7 2022 (g)	8 2023 (h)	9 2024 (i)	10 2025 (j)	11 2026 (k)	12 2027 (l)	13 2028 (m)	14 2029 (n)
	Rate Base Investment														
1	Capital Expenditures	4,259	179	80	63	52	61	59	61	58	53	0	0	0	0
2	Average Investment	1,334	3,923	3,612	3,196	2,891	2,858	2,828	2,796	2,763	2,725	2,664	2,568	2,472	2,376
	Revenue Requirement Calculation:														
	Operating Expenses:														
3	Operating and Maintenance Expenses	1	7	14	18	21	24	27	30	33	36	39	40	41	42
4	Depreciation Expense	55	108	101	92	88	90	91	93	94	96	96	96	96	96
5	Property Taxes	16	49	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	73	164	164	160	158	163	167	171	176	181	184	186	187	188
7	Required Return (5.77% x line 2)	77	226	208	184	167	165	163	161	159	157	154	148	143	137
	Income Taxes:														
8	Income Taxes - Equity Return	15	45	42	37	33	33	33	32	32	32	31	30	29	27
9	Income Taxes - Utility Timing Differences	(24)	(45)	(37)	(29)	(24)	(21)	(19)	(16)	(14)	(12)	(9)	(7)	(4)	(2)
10	Total Income Taxes	(9)	0	4	8	10	12	14	16	18	20	21	23	24	26
11	Total Revenue Requirement (line 6 + line 7 + lir	141	391	377	352	335	339	344	349	353	357	359	357	354	350
12	Incremental Revenue	9	43	81	102	115	125	135	146	157	168	176	179	179	179
13	TES and ITE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	9	43	81	102	115	125	135	146	157	168	176	179	179	179
15	Net Revenue Requirement (line 11 - line 14)	132	348	296	249	220	214	209	202	196	190	183	178	175	172

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion I
TES, ITE as Aid

Line No.	Particulars ($000's)	15 2030 (o)	16 2031 (p)	17 2032 (q)	18 2033 (r)	19 2034 (s)	20 2035 (t)	21 2036 (u)	22 2037 (v)	23 2038 (w)	24 2039 (x)	25 2040 (y)	26 2041 (z)	27 2042 (aa)	28 2043 (ab)
	Rate Base Investment														
1	Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Average Investment	2,280	2,184	2,087	1,991	1,895	1,799	1,703	1,606	1,510	1,414	1,318	1,221	1,125	1,029
	Revenue Requirement Calculation:														
	Operating Expenses:														
3	Operating and Maintenance Expenses	43	45	46	47	48	49	48	44	41	41	41	41	42	42
4	Depreciation Expense	96	96	96	96	96	96	96	96	96	96	96	96	96	96
5	Property Taxes	49	49	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	189	190	191	192	193	194	194	189	186	186	187	187	187	188
7	Required Return (5.77% x line 2)	132	126	120	115	109	104	98	93	87	82	76	70	65	59
	Income Taxes:														
8	Income Taxes - Equity Return	26	25	24	23	22	21	20	19	17	16	15	14	13	12
9	Income Taxes - Utility Timing Differences	0	2	4	6	8	9	11	12	14	15	16	17	18	19
10	Total Income Taxes	27	28	28	29	30	30	31	31	31	31	31	31	31	31
11	Total Revenue Requirement (line 6 + line 7 + lir	347	344	340	336	332	328	323	313	304	299	294	289	283	278
12	Incremental Revenue	179	179	179	179	179	179	172	156	152	151	149	148	147	146
13	TES and ITE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	179	179	179	179	179	179	172	156	152	151	149	148	147	146
15	Net Revenue Requirement (line 11 - line 14)	168	165	161	157	153	149	151	157	152	149	145	140	137	133

UNION GAS LIMITED
Revenue Requirement of the Milverton Community Expansion I
TES, ITE as Aid

Line No.	Particulars ($000's)	29 2044 (ac)	30 2045 (ad)	31 2046 (ae)	32 2047 (af)	33 2048 (ag)	34 2049 (ah)	35 2050 (ai)	36 2051 (aj)	37 2052 (ak)	38 2053 (al)	39 2054 (am)	40 2055 (an)
	Rate Base Investment												
1	Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0
2	Average Investment	933	837	741	644	548	452	356	260	178	130	105	82
	Revenue Requirement Calculation:												
	Operating Expenses:												
3	Operating and Maintenance Expenses	42	43	43	44	45	45	46	47	47	47	47	47
4	Depreciation Expense	96	96	96	96	96	96	96	96	68	27	23	23
5	Property Taxes	49	49	49	49	49	49	49	49	49	49	49	49
6	Total Operating Expenses	188	188	189	189	190	191	191	192	164	123	119	119
7	Required Return (5.77% x line 2)	54	48	43	37	32	26	21	15	10	8	6	5
	Income Taxes:												
8	Income Taxes - Equity Return	11	10	9	7	6	5	4	3	2	2	1	1
9	Income Taxes - Utility Timing Differences	20	21	22	23	23	24	25	25	16	1	1	1
10	Total Income Taxes	31	31	30	30	30	29	29	28	18	3	2	2
11	Total Revenue Requirement (line 6 + line 7 + lir	273	267	262	257	251	246	241	235	192	133	127	126
12	Incremental Revenue	144	143	142	142	142	142	142	142	142	142	142	142
13	TES and ITE	-	-	-	-	-	-	-	-	-	-	-	-
14	Incremental Revenue with TES and ITE	144	143	142	142	142	142	142	142	142	142	142	142
15	Net Revenue Requirement (line 11 - line 14)	129	124	120	114	109	104	98	93	50	(9)	(15)	(16)

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 17-21

a) How will Union take into account that some contract customers may hit their MAV (due to weather, production increases, etc.) whereas other contract customers may have consumption below this level (page 17)? Does this mean that some contract customers may end providing required financial contributions while others do not?

b) Why is Union not proposing a CIAC with the option of monthly payments for a pre-determined period as opposed to a one-time payment?

c) Please expand Table 1 to include a residential customer that uses solar water heating and a ground source heat pump for water and space heating. Please provide all assumptions used in terms of energy use.

d) What is the basis for the determination of a desired payback period of 3.75 years?

e) What evidence does Union have that the expected annual consumption of residential customers in these new service areas will be 2,200 m3 per year?

f) What assumptions has Union used to determine that the 2,200 m3 per year is a realistic expectation for the annual use for the projects proposed in this application? For example, what assumptions have been used for water heating (tank vs. tankless)?

g) What is the impact on the economics of the projects and the level of subsidy proposed by Union from existing ratepayers if the actual annual residential use is above or below 2,200 m3? Please explain fully.

h) Does the TES rate remain fixed for the entire term, or does it get adjusted to reflect actual annual consumption?

i) Will the TES rate be the same for all projects, or will it be project specific to reflect different annual consumptions expected for residential customers in different project areas, due to weather differences, house size and age differences, etc.? If not, why not?

j) How was the maximum TES term of 10 years determined? Similarly, how was the minimum term of 4 years determined?

k) Please explain why it is appropriate for different projects to have different terms for the TES and ITE. In other words, why should customers have to pay the additional costs for 10 years while others pay for only 4 years, both for projects which are subsidized by existing customers?

l) Please explain why it is appropriate that a customer that connects near the end of the TES term effectively pays less than a customer that connects near the beginning of the term for the same long term benefit of having access to natural gas.

m) Does Union have any concerns that general service customers may delay the switch to natural gas to avoid the cost of the TES, in addition to delaying the conversion costs that they will incur?

Response:

a) A contract customer can choose to contract for a higher minimum annual volume ("MAV") than needed to meet their required financial contribution to the project. If a customer's annual consumption is less than their contracted MAV, Union will invoice the customer the difference between their contractual MAV and their actual annual consumption to ensure Union receives the required financial contribution.

Each contract customer will make the required financial contribution to the project at minimum because Union will bill their MAV regardless of their actual annual consumption. If a customer contributes more because they have exceeded their MAV, the benefits will be subject to earnings sharing under Union's IRM framework.

b) Please see the response at Exhibit B.LPMA.1 b).

c) The table below shows Table 1 amended to include ground source ("GS") heat pump.

Annual Residential Energy Savings Estimates

Competing Energy Source	Penetration	Union South	Union North
Oil	35%	$1,886	$1,512
Wood	28%	$813	$813
Electric	22%	$2,303	$2,082
Electric GS/Solar[1]	0%	$388 to $754	$388 to $754
Propane	15%	$1,679	$1,696
Weighted Average[2]	**100%**	**$1,646***	**$1,469***

---

[1] Heat pump/geo furnace using 6,926 to 9,680 kwh/year, and solar thermal water heater with electrical back-up using 2,365 kwh/year. Annual electricity consumption would be 33 to 43 GJ. Annual savings have not been calculated separately for Union North and Union South.
[2] Using Union's general customer distribution of 75% South and 25% North, franchise wide average savings are $1,602.

The initial installation cost for the geothermal heating system is approximately $26,000 to $30,000 and the cost of the solar thermal water system $7,000 to $8,000. This would result in a very long payback period to recover initial investment. There are currently approximately 100,000 geothermal heating and cooling system installed in Canada (Canadian GeoExchange Coalition). Considering this number, the Ontario installed Geo share would be less than 1%. Attachment 1 provides details on calculations.

d) Please see the response at Exhibit B.CCC.7.

e) In estimating average annual savings from converting to natural gas, Union has used an average residential consumption of 2,200 m^3 per year. This figure is used commonly in Union's rate-related communications with customers. It is slightly lower than the normalized residential annual consumption figures approved by the Board in Union's most recent Cost of Service Application (EB-2011-0210); 2,237 m^3 and 2,342 m^3 per year for Union South and Union North customers, respectively. For the purpose of economics, Union has used 2,237 m^3 per year for Union South and 2,342 m^3 per year for Union North because it anticipates the energy requirements for the area to be similar to Union South and Union North averages.

f) Please see the response to e) above.

g) As noted in part e) above, the economics used average residential at 2,237 m^3 for Union South and 2,342 m^3 for Union North. Variances in gas usage will have a muted impact on gas delivery revenues due to the fixed portion of the rate. Higher usage will also increase the collection of the TES that is credited back to rate payers through the deferral account, with an opposite affect for lower than forecast usage.

h) As noted in the response at Exhibit B.CCC.9, the TES rate and term will not be adjusted regardless of consumption.

i) The TES rate will remain constant for all Projects. However, the term will vary based on the project economics for each Project. If Union believes that a value other than NAC should be used in project economics, this value would be included in the application to the Board for that Project.

j) With respect to the maximum term, please see the response at Exhibit B.EGD.3.

   With respect to the minimum term, Union applied its judgment to determine that if existing ratepayers were to financially support Community Expansion Projects, it would be unfair to not expect the customers served by those Projects not to make a significant contribution as well. A TES for four years equates to about $2,000 for a typical residential home. Union has had a very small number of customers in the past year who have been willing to pay $2,000 in Aid-to-Construction to connect therefore Union considered that minimum value would be appropriate. Four years also coincided with what Union judged to be a reasonable payback period for the cost of converting equipment.

k) The TES and ITE terms are determined by the length of time it takes for the TES and ITE payments to allow a project to achieve the minimum P.I. of 0.4. If one project can reach that threshold more quickly than another, it would have a shorter TES term. Those customers who would be paying TES for a longer period are doing so because the Project to serve them is less cost effective. This is very consistent with the historic application of Aid-to-Construction, whereby each customer is required to pay the necessary Aid to allow their connection to the system to reach the minimum economic thresholds in place.

l) Union's approach satisfies the principle that contributions made by Community Expansion Project customers be commensurate with the savings achieved, as noted in line 10 at Exhibit A, Tab 1, p. 6. Assuming the fixed TES term for a specific project is established at 10 years, a customer who connects in year 10 will have not benefited from the annual energy savings for the past nine years. If a customer connects in year 10 it would be inconsistent with this principle to expect that customer to pay the same amount of TES over time as the one who connected in year 1.

m) No. Union will not be concerned that general service customer may delay the switch to natural gas to avoid the cost of the TES. The volumetric TES with a fixed term length addresses this concern. Customers who chose not to connect will pay higher energy costs every year they delay the decision. When customers do decide to connect they will be subject to the TES from the date of connection until the community TES term expires. Given the magnitude of annual energy savings, Union does not expect to see customers delaying as a result of the TES.

Average Ontario Estimated Annual Cost of Energy (82 GJ/Year)

Year	Propane	Furnace Oil	Electricity TOU	Natural Gas
2006	$ 1,894	$ 1,891	$ 2,348	$ 1,229
2007	$ 1,912	$ 1,984	$ 2,291	$ 967
2008	$ 2,184	$ 2,369	$ 2,231	$ 1,080
2009	$ 2,065	$ 1,831	$ 2,457	$ 932
2010	$ 2,124	$ 2,080	$ 2,609	$ 729
2011	$ 2,425	$ 2,611	$ 2,547	$ 772
2012	$ 2,587	$ 2,717	$ 2,701	$ 724
2013	$ 2,645	$ 2,795	$ 2,839	$ 744
2014	$ 2,724	$ 2,981	$ 3,142	$ 853
2015	$ 2,527	$ 2,636	$ 3,308	$ 843
2015 NG Savings	$ 1,683	$ 1,792	$ 2,464	elect less fixed

Note: assumed South at 75% and North at 25% weightings.

Sources:

Propane & Heating Oil: The Kent Group. Rates taken for London for the South and T. Bay for the North

Natural Gas: Union Gas Limited Rate Schedules

Electricity: OEB time-of-use rates & utility-specific charges. Rates taken for London for the South and Thunder Bay for the North

Fixed Monthly Rate: Hydro One medium density monthly fixed charge $ 24.07

Average Annual Savngs Relative to Natural Gas (82 GJ/Year)

Year	Propane	Furnace Oil	Electricity TOU	Electricity TOU excl remaining Fixed Monthy Charges
2006	$ 664	$ 661	$ 1,119	$ 830
2007	$ 945	$ 1,017	$ 1,324	$ 1,035
2008	$ 1,104	$ 1,289	$ 1,151	$ 862
2009	$ 1,133	$ 899	$ 1,525	$ 1,236
2010	$ 1,395	$ 1,351	$ 1,880	$ 1,591
2011	$ 1,654	$ 1,839	$ 1,775	$ 1,486
2012	$ 1,863	$ 1,993	$ 1,976	$ 1,688
2013	$ 1,901	$ 2,051	$ 2,095	$ 1,806
2014	$ 1,871	$ 2,128	$ 2,289	$ 2,000
2015	$ 1,683	$ 1,792	$ 2,464	$ 2,175
savings/GJ	$ 20.53	$ 21.86	$ 30.05	$ 26.53

LPMA 2.b) Ground Source/Solar (33-43 GJ/Year Comparison)

Year	Propane	Furnace Oil	Electricity TOU	Electricity TOU excl remaining Fixed Monthy Charges
33.44 GJ:				
2015	$ 1,683	$ 1,792	$ 677	$ 388
43.40 GJ:				
2015	1,683	1,792	1,043	$ 754

Notes on Ground Source/Solar System

1- Electrical equipment Heating Load (kW)/yr:
Heat Pump- Geo 6,926-9,680 kw/yr
Solar thermal with Electrical backup 2,365 kw/yr
TOTAL 9,291-12,045 kwh/yr, or 33.44-43.40 GJ

2- The initial installation cost for the geothermal system is around $26,000-$30,000 and the cost of the solar thermal $7,000-$8000.

3- The Heat Pump COP (2.5) is an average COP based on the CGC (Canadian GeoExchange Coalition).

3- There are currently 100,000 geothermal heating and cooling system installed in Canada (Canadian GeoExchange Coalition). Considering this number, the Ontario installed GS share would be significantly less than 1%.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 26 & Appendix D

a) Are the figures shown in Table 3 cumulative? For example at a minimum PI of 0.6, there are 21 projects and 22 communities. Do these figures include the 14 projects and 15 communities shown for a minimum PI of 0.5?

b) Please explain what is meant by "natural PI" in Appendix D.

c) For each of the projects listed in Appendix D for which Union is seeking approval in this application, please provide the term of the TES and ITE to achieve a PI of 0.8.

Response:

a) Each line in the Table is independent and not cumulative. For example, the number of projects at P.I. 0.6 is 14. If the P.I. limit is 0.5 the total is 21 (i.e. 7 more projects).

b) The footnote on p.3 of Appendix D is the description:

"Project profitability index based on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing."

Put more generally, it is the P.I. before addition of contributions from customers, municipalities or government sources (if any).

c) Please see the Table below.

	Project	TES Term As Proposed Years	ITE Term as Proposed Years	TES Term for P.I. of 0.8 Years	ITE Term for P.I. of 0.8 Years	Notes
1	Milverton	4	4	7	7	
2	Moraviantown	4	4	8	8	
3	Prince Township	4	4	12	12	
4a	Kettle Point	4	4	5	5	(a)
4b	Lambton Shores	7	-	7	-	(a)

Note: The term has been rounded to the closest year to the threshold

(a) Kettle Point/Lambton Shores is one project spread across two municipalities
For IR response to PI of 0.8 Union has simplified the calculation by applying one additional year to the combined Kettle Point/Lambton Shores Project. If the Board requires a criteria of 0.8, further calculations would be required to better pro-rate the requirements to each municipal area.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 27

a) Please explain what is meant by incremental common project costs (line 7) for contract customers.

b) If the contract customer required a firm CD that resulted in an increase in the size of pipe to the community being served, would that contract customer be responsible for the incremental cost of the project, or would the cost of the larger pipe be recovered from all customers?

c) If the contract customer required a firm CD that resulted in no change in the size of the pipe to the community being served, what incremental costs would that contract customer be responsible for, and in particular, would they pay a port of the cost of the pipe to the community?

Response:

a) Please see the response at Exhibit B.CCC.12.

b) Please see the response at Exhibit B.CCC.12.

c) In this case there would be no incremental common project costs. As a result, the contract customer would not be required to pay for any portion of the common project costs.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 28-31

a) How many of the five proposed projects could be completed with the Investment Portfolio remaining at or above the EBO 188 minimum requirement?

b) What is the impact on the PI of 1.02 noted on line 15 of page 29 if the PI for each of the individual projects was set at:

i) 0.5;
ii) 0.6; and
iii) 0.7?

c) For each of the three PI's requested in part (b) above, please provide a revised version of Table 4 showing the impact on the rolling project portfolio.

d) Is Union concerned about the discrimination in requiring community expansion customers to pay to raise the PI to as little as 0.4, while requiring new customers that are not included in a community expansion to pay to raise the PI to 0.8? If not, please explain fully.

Response:

a) Union could complete two of the Projects in Union South and the one Project in Union North before the forecast of the Investment Portfolio would fall below 1.10.

Union South: Lambton Shores/Kettle Point and Moraviantown
Union North: Prince Township

b) The reference to a P.I. of 1.02 in the evidence at Exhibit A, Tab 1, p. 28, line 15 is for Union South. As noted in the table below, Union North would not fall below P.I. 1.10 from this Application as it has only the Prince Township Project.

		2016 IP Including Community Expansions Project P.I. level			
	IP prior to Application	0.4	0.5	0.6	0.7
North	1.25	1.17	1.17	1.18	1.18
*South	1.14	1.02	1.03	1.03	1.04
Company	1.18	1.08	1.09	1.09	1.10

*Data excludes Walpole Island First Nations as Union has withdrawn this project from the Application

c) Please see Attachment 1.

d) Union has developed its proposal to respond to the government's goal to "provide consumers in underserved communities more energy choices…" as noted in Premier Wynne's mandate letters[1] to the Minister Energy, the Minister of Economic Development, Employment and Infrastructure, and the Minister of Agriculture, Food, and Rural Affairs.

The current E.B.O. 188 guidelines permit project P.I.'s of as low as 0.8, provided the Rolling Project Portfolio retains a P.I. above 1.0 and the investment portfolio P.I remains above 1.1. In order to undertake any new projects at a P.I. of 0.8, then, Union is required to ensure that there are enough other projects undertaken at P.I.'s above 1.0 to ensure their positive NPV offsets the negative NPV of the lower P.I. project. Based on this requirement the discrimination described in the question already exists to a certain extent within the E.B.O. 188 framework.

Union is not concerned about discrimination because there are broader benefits to Community Expansion Projects as outlined at Exhibit B.CCC.5 that would not be as prevalent with a small main expansion project to service only a few customers. Please also see the response at Exhibit B.VECC.11 b) for a description of why the minimum size of 50 homes and businesses is proposed.

Union notes that generally projects that are not considered Community Expansion Projects will require a minimum P.I of 1.0, as opposed to the 0.8 referenced in the question.

[1] All letters are included in Exhibit A, Tab 1, Appendix N.

Table 4
Impact of Community Expansion Projects on Rolling Project Portfolio
($ millions)

	As Filed	Union South				Union North				Corporate			
		Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Most Recent 3 year Average	$31.5	$20.5	1.54	$11.1	$13.6	$10.1	1.35	$3.5	$45.1	$30.6	1.48	$14.6
2	Milverton	$2.6	$4.7	0.57	-$2.0					$2.6	$4.7	0.57	-$2.0
3	Prince Township					$1.3	$2.6	0.49	-$1.3	$1.3	$2.6	0.49	-$1.3
4	Kettle Point and Lambton Shores	$1.2	$1.8	0.66	-$0.6					$1.2	$1.8	0.66	-$0.6
5	Walpole Island	$0.4	$1.1	0.40	-$0.6					$0.4	$1.1	0.40	-$0.6
6	Moraviantown	$0.3	$0.5	0.57	-$0.2					$0.3	$0.5	0.57	-$0.2
7	**3 Year Average Plus 5 projects**	**$36.0**	**$28.4**	**1.27**	**$7.6**	**$14.9**	**$12.7**	**1.17**	**$2.2**	**$50.9**	**$41.1**	**1.24**	**$9.8**

	Minimum PI = 0.5	Union South				Union North				Corporate			
		Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV
8	Most Recent 3 year Average	$31.5	$20.5	1.54	$11.1	$13.6	$10.1	1.35	$3.5	$45.1	$30.6	1.48	$14.6
9	Milverton	$2.6	$4.7	0.57	-$2.0					$2.6	$4.7	0.57	-$2.0
10	Prince Township					$1.3	$2.6	0.50	-$1.3	$1.3	$2.6	0.50	-$1.3
11	Kettle Point and Lambton Shores	$1.2	$1.8	0.66	-$0.6					$1.2	$1.8	0.66	-$0.6
12	Moraviantown	$0.3	$0.5	0.57	-$0.2					$0.3	$0.5	0.57	-$0.2
13	**3 Year Average Plus 4 projects**	**$35.6**	**$27.4**	**1.30**	**$8.3**	**$14.9**	**$12.7**	**1.17**	**$2.2**	**$50.5**	**$40.1**	**1.26**	**$10.5**

	Minimum PI = 0.6	Union South				Union North				Corporate			
		Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV
14	Most Recent 3 year Average	$31.5	$20.5	1.54	$11.1	$13.6	$10.1	1.35	$3.5	$45.1	$30.6	1.48	$14.6
15	Milverton	$2.8	$4.7	0.60	-$1.9					$2.8	$4.7	0.60	-$1.9
16	Prince Township					$1.6	$2.6	0.60	-$1.1	$1.6	$2.6	0.60	-$1.1
17	Kettle Point and Lambton Shores	$1.2	$1.8	0.66	-$0.6					$1.2	$1.8	0.66	-$0.6
18	Moraviantown	$0.3	$0.5	0.60	-$0.2					$0.3	$0.5	0.60	-$0.2
19	**3 Year Average Plus 5 projects**	**$35.8**	**$27.3**	**1.31**	**$8.4**	**$15.2**	**$12.7**	**1.19**	**$2.4**	**$51.0**	**$40.1**	**1.27**	**$10.9**

	Minimum PI = 0.7	Union South				Union North				Corporate			
		Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV	Inflow	Outflow	PI	NPV
20	Most Recent 3 year Average	$31.5	$20.5	1.54	$11.1	$13.6	$10.1	1.35	$3.5	$45.1	$30.6	1.48	$14.6
21	Milverton	$3.3	$4.7	0.70	-$1.4					$3.3	$4.7	0.70	-$1.4
22	Prince Township					$1.9	$2.6	0.70	-$0.8	$1.9	$2.6	0.70	-$0.8
23	Kettle Point and Lambton Shores	$1.3	$1.8	0.73	-$0.5					$1.3	$1.8	0.73	-$0.5
24	Moraviantown	$0.3	$0.5	0.70	-$0.1					$0.3	$0.5	0.70	-$0.1
25	**3 Year Average Plus 5 projects**	**$36.4**	**$27.3**	**1.33**	**$9.1**	**$15.5**	**$12.7**	**1.21**	**$2.7**	**$51.9**	**$40.1**	**1.29**	**$11.8**

Notes:
The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8.
It no longer requires Union’s Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 31-32 & Appendix F & Appendix D

a) What is the total capital cost of the 5 projects Union is proposing in this application?

b) Please provide a table that shows a summary of the information provided in Appendix F that is the total annual revenue requirement impact for each of 2016 through 2018 for the 5 projects Union is proposing in this application in aggregate? Please break out the total revenue requirement for each year into its components, such as O&M, cost of debt, return on equity, depreciation, income taxes, property taxes, etc.

c) Do the natural PI's and gross capital costs shown in Appendix D include any upfront CIAC that is received (i.e. provincial funding) that is noted on page 32?

d) What provincial funding does Union expect to receive for each of the 5 projects that Union is proposing in this application?

e) What is the level of provincial funding required for each of the projects if the PI for each project was required to be:

i) 0.5;
ii) 0.6; and
iii) 0.7,

assuming that the TES, ITE and contract customer contributions were maintained, as proposed by Union?

Response:

a) The total capital cost of the four projects in this Application is $9.77 million.[1]

b) Please see the response at Exhibit B.EnergyProbe.19.

c) No. They exclude TES, ITE and any form of Aid-to-Construction.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

d) None. Please see the response at Exhibit B.Energy Probe.3 c) for further details.

e) Please see the response at Exhibit B.LPMA.14 c).

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 32-33

a) Please confirm that the Community Expansion Project Deferral Account would not be impacted by differences between forecasted revenue and actual revenue from any of the projects. If this cannot be confirmed, please explain.

b) How does Union propose to deal with the difference between forecast volumes and actual volumes with regards to the TES and ITE revenue in the Community Expansion Contribution Deferral Account? In particular, will Union or ratepayers be at risk for differences in forecast and actual volumes to which the TES applies?

Response:

a) Not confirmed. The Community Expansion Project Deferral Account will record the variance between the forecast net revenue requirement included in rates and the actual net revenue requirement for all Community Expansion Projects. The deferral account will include variances in forecast and actual distribution revenue associated with differences between forecast customer attachments and volumes and actuals.

b) The Community Expansion Contribution Deferral Account will record the TES contributions from community expansion customers and ITE contributions from municipalities. The TES contributions recorded in the deferral account will be based on actual volumes. Accordingly, ratepayers will be at risk (or benefit) from any differences between the volumes assumed in the calculation of the TES and actual volumes.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 22

a) Will the ITE revenue collected from the municipalities be equal to the actual value of the incremental property taxes collected from Union as a result of the project? If not, please explain fully how the estimated taxes have been estimated.

b) Has Union negotiated such a deal with each of the municipalities impacted by the five projects for which Union is seeking approval in this application? Please provide details, if applicable, of any such agreements.

Response:

a) Yes. Please see the response at Exhibit B.CPA.12 b).

b) Please see the response at Exhibit B.CPA.12 e) and Exhibit B.CCC.10.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 30

The evidence states that Union can complete approximately 30 projects under its proposal. Does this figure reflect provincial funding, or is it based on no provincial funding received for any of the projects?

Response:

No provincial funding would be required to complete the 30 potential Projects based on Union's proposal.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 36-37

a) Please confirm that the figures provided in Tables 5 and 6 do not assume any provincial loans or grants. If this cannot be confirmed, please provide the amount of provincial grants or loans included in the calculations.

b) Please confirm that in order to achieve of PI and rolling PI of 1.0 at the corporate level, the incremental investments would need a PI of about 0.8.

Response:

a) Confirmed.

b) Union presumes the question has a typographic error with the phrase…"to achieve of P.I. and rolling…"

Union has responded based on the following question.

Please confirm that in order to achieve an IP and rolling P.I. of 1.0 at the corporate level, the incremental investments would need a P.I. of about 0.80.

Not confirmed. Every incremental Project at a P.I. less than 1.0 will reduce the overall corporate IP and Rolling P.I. The amount of "reduction" is an outcome of both the size of the investment and the resulting P.I., not just the P.I. As stated in evidence, Union has requested the Community Expansion Projects be exempted from the E.B.O 188 requirements because the IP and RPP cannot bear the impacts.

Please also see the response at Exhibit B.LPMA.5.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 38

Please provide a stage 2 analysis, including each of the three alternative scenarios referenced, including the additional costs to be paid for by existing customers over the 40 year horizon used in the net present value calculation, as noted on page 39.

Response:

The revenue requirement net of revenue and TES and ITE for the 30 Projects as filed is an NPV of ($80) million. This is the NPV in regards to the approximate spend of $150 million as referenced in Exhibit A, Tab 1, p. 39, line 4. Please see the table below for the results when added to the Stage 2 benefits referenced in the question. The alternative scenarios are described in evidence.

	Stage 1 NPV ($ million)	Stage 2 ($ million)	Total Stage 1 + Stage 2 ($ million)
Base case (as filed)	(80)	324	244
Limit savings to 30 years	(80)	262	162
60% attachment rate	(80)	278	198
47% attachment rate	(80)	248	168

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, p. 40

a) Please explain fully why Union is proposing that the TES and ITE contributions be rebated to customers on an annual basis, rather than be accounted for as capital contributions that would reduce rate base, thereby reducing the revenue requirement for all future years to reflect the reduction in the cost of debt, return on equity, depreciation and income taxes.

b) Please explain how Union plans to treat any contributions received from contract customers.

c) Please explain how Union plans to treat any provincial loans or grants received.

Response:

a) Please see the response at Exhibit B.LPMA.1 b).

b) In cases where a contract customer wishes to connect to the system but their connection would not meet the minimum economic feasibility threshold, they have several options available for consideration:

- Pay any required Aid-to-Construction contribution ("CIAC") in which case the CIAC is recorded as an Aid-to-Construction to reduce the capital costs included in rate base (note: CIAC is an upfront payment).
- Extend the term of their contract in order to make the project feasible[1].
- Increase their Minimum Annual Volume ("MAV"), or committed revenue, in which case if their consumption in any year during the term of the contract is below the contracted MAV a final (13^{th}) bill is sent to the customer for the difference between actual and minimum contracted volume. This billing is recorded as distribution revenue.
- Negotiate a rate which is higher than the minimum rates provided in the applicable rate schedules, in which case the billing is recorded as distribution revenue.

Any combination of these options can be considered, depending on the rate class.

c) Any funding sourced from up-front provincial loans or grants will be recorded as a CIAC to reduce the capital costs included in rate base.

[1] This approach provides for additional years of revenue to be considered in the economic analysis.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 42-43

a) Please explain how Natural Gas Access Loans would be treated as an aid-to-construction by Union. For example, are the loans expected to be made available to Union, customers or municipalities?

b) Does Union have any more up to date information related to provincial funding than it did when the evidence was created? If yes, please provide details. If no, will Union commit to providing any information or knowledge it obtains related to the provincial loans and grants as soon as Union is able to provide it to parties?

c) Approximately what percentage of the $200 million in Natural Gas Access Loans and $30 million in Natural Gas Economic Development grants does Union believe would flow to its franchise territory as opposed to the territories of other distributors?

d) Please provide a table that shows for each of the 30 projects for which Union has indicated that it would proceed with, the aid-to-construction from provincial loans or grants that would result in a PI of 0.5, 0.6, 0.7 and 0.8.

Response:

a) Please see the response at Exhibit B.CCC.16.

b) Union does not have any additional information at this time, except that Union has offered to provide input to the extent that it would be helpful to the Government. When additional information becomes available Union expects it would be available publicly so Union sees no need to provide it to other parties.

c) Because the criteria and surrounding process for the loans and grants are as yet unavailable, Union cannot provide an estimate of the portion that would flow to Union's franchise territory.

d) Attachment 1 to this response is a table with the requested data. The methodology used is to first extend the term of the TES/ITE contribution up to the maximum of 10 years. If the PI has not met the threshold of the question an Aid-to-Construction has been calculated. Row numbers in Attachment 1 correspond to the row numbers in Exhibit A, Tab 1, Appendix D.

Required CIAC Summary

Row	Community Name	Min PI= 0.5 CIAC Required (millions)	Min PI=0.6 CIAC Required (millions)	Min PI=0.7 CIAC Required (millions)	Min PI=0.8 CIAC Required (millions)
1	Milverton				
2	Prince Township, Sault Ste Marie				$0.32
3	Lambton Shores, Kettle Point First Nation				
4	~~Walpole Island First Nation- main commercial area~~	Removed from application			
5	Moraviantown First Nation- main commercial area				
6	Lagoon City (Orillia)				$0.39
7	Hidden Valley/Huntsville				$0.04
8	Santa's Village/Beaumont Dr, Bracebridge				$0.11
9	Canal, Gravenhurst			$0.10	$0.26
10	Northshore Rd / Peninsula Rd North Bay			$0.30	$0.59
11	Hornby		$0.23	$0.41	$0.53
12	Oneida First Nation			$0.01	$0.33
13	Auburn				$0.06
14	Cedar Springs			$0.05	$0.18
15	Astorville		$0.21	$0.81	$1.23
16	~~***Brenman Line, Servern Twp (Gravenhurst)~~				
17	Nipissing First Nation / Jocko Point		$0.44	$1.03	$1.45
18	~~***Munsee Delaware First Nation~~				
19	Chippewa of the Thames First Nation- phase 3 & 4		$0.06	$0.17	$0.25
20	Sheffield		$0.07	$0.20	$0.29
21	Turkey Point		$0.69	$1.20	$1.57
22	Rockton		$0.16	$0.28	$0.37
23	Chippewas of the Saugeen		$0.17	$0.30	$0.38
24	Washago	$0.48	$1.25	$1.75	$2.10
25	E Floral (T Bay area)	$0.08	$0.29	$0.43	$0.53
26	Haldimand Shores	$0.16	$0.37	$0.88	$1.01
27	Latchford, Tri Town	$0.58	$0.95	$1.19	$1.36
28	Belwood	$0.61	$1.71	$2.43	$2.92
29	Kincardine. Tiverton, Paisley, Chesley	$1.90	$15.74	$24.57	$30.83
30	~~***Little Longlac~~				
31	Swiss Meadow	$0.24	$0.40	$0.51	$0.59
32	Boblo Island	$0.72	$1.14	$1.41	$1.60
33	Village of Warwick	$0.41	$0.64	$0.79	$0.89
	Total	**$5.19**	**$24.54**	**$38.83**	**$50.19**

*** Project does not meet definition of Community Expansion Project so would not be eligible for reduced PI without additional project scope. Therefore no data has been provided in this table.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 44-46

a) Is the difference in the capital costs shown in Table 8 (Preferred Design and Minimum Design) based on the difference in costs noted on page 44 at lines 6-11?

b) Does Union propose to include the incremental cost associated with the preferred design in the amounts to be recovered from existing customers? If yes, please explain fully why existing customers should pay this additional cost.

c) Please expand Table 8 to include four columns that show the provincial funding needed as an aid-to-construction required for each project to reach a PI of 0.5, 0.6, 0.7 and 0.8, respectively.

d) Please provide a version of Table 8 that shows the PI for each project if the TES/ITE period is extended to 60 months where it is currently proposed to be 48 months.

e) Given the current schedule for this proceeding, Union will not receive a decision before December 31, 2015. What is the latest date that Union could receive a decision in 2016 and still complete the projects in time to service the customers in the 2016 timeframe?

Response:

a) Yes.

b) Yes.

Union has historically only considered minimum design cost in project economics and calculations of any required Aid-to-Construction necessary to make a project economically feasible. This approach has appeared consistently in Union's Distribution New Business Guidelines, which have been filed in previous cost of service applications. Union has not adjusted this historic approach for the Community Expansion Project proposal.

Union's proposal to continue considering only the costs to install the minimum necessary infrastructure required to serve a project in the economics for that project is consistent with historical approach.

Minimum design costs are the cost for the minimum size, pressure and length of natural gas infrastructure to service a specific load request. In designing a system to respond to a specific attachment load request Union may make a decision to increase size, pressure or length in order to meet one or more coincidental needs, for example:

- Allowing for future growth off that system (beyond the customer forecast period for the project being requested);
- Avoiding or mitigating other future expected costs such as reinforcement of the upstream system; and,
- Gaining economies of scale with other work on the related system in the near future, such as leakage or municipal road work related replacement or relocation.

These situations may result in a preferred design alternative being recommended.

In most cases where a preferred design is recommended, the reason is to facilitate future system growth. For example, it would be unwise to expect to loop a new pipeline with another pipeline to get additional capacity for growth a few years after the initial pipeline is installed. It would be much less costly to simply increase the pipe size of the initial installation to provide for the anticipated additional capacity.

In situations where a preferred design is recommended, it would be unfair to ask the customer who has requested additional load to pay for the incremental costs of the preferred design over the minimum design. The preferred design is being recommended for reasons other than to service the specific load request (primarily future system growth), so incremental costs for the preferred design should be allocated to the issue driving the recommendation.

The capital pass-through mechanism is designed to recover actual costs. If the preferred design is used, it should be passed through to ratepayers subject to the normal prudence test.

c) Union's TES/ITE proposal is based on a minimum term of four years and a maximum term of 10 years. The methodology is to calculate the P.I. for the project for a term that meets the P.I. threshold (0.4 in Union's proposal). If the threshold is not met with a term of 10 years, an Aid-to-Construction is calculated.

   Please see Attachment 1. The P.I. can meet each requested threshold without exceeding 10 years and therefore no Aid-to-Construction is required. The term is shown in Attachment 1.

d) Please see Attachment 2.

e) If a Board Decision is received by April 15, 2016, Union would immediately initiate the projects and for those where all materials are readily available, expects the projects to be in service by year-end.

Table 8
Proposed Community Expansion Projects

						As Filed				Min PI = 0.5				Min PI = 0.6				Min PI = 0.7				Min PI = 0.8			
	Community	**Maximum Potential Customers**	**Forecast Customers**	**Capital Cost**		**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**	**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**	**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**	**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**	**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**
				Preferred	**Minimum**	**TES**	**ITE**			**TES**	**ITE**			**TES**	**ITE**			**TES**	**ITE**			**TES**	**ITE**		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	Milverton	818	526	$4.93	$4.77	$1.01	$0.15	48	0.57	$1.01	$0.15	48	0.57	$1.12	$0.19	50	0.60	$1.58	$0.22	71	0.70	$1.99	$0.28	85	0.80
2	Prince Township	375	242	$2.72	$2.72	$0.22	$0.09	48	0.50	$0.22	$0.09	48	0.50	$0.45	$0.15	83	0.60	$0.68	$0.19	112	0.70	$0.72	$0.20	120	0.80
3	Lambton Shores/ Kettle Point FN	496	281	$2.42	$1.79	$0.51	$0.01	82/48	0.73	$0.51	$0.01	82/48	0.73	$0.51	$0.01	82/48	0.73	$0.51	$0.01	82/48	0.73	$0.63	$0.02	82/72	0.80
4	Moraviantown	70	61	$0.54	$0.49	$0.10	$0.02	48	0.58	$0.10	$0.02	48	0.58	$0.10	$0.02	50	0.60	$0.15	$0.03	73	0.70	$0.19	$0.04	96	0.80
5	**Total**	**1759**	**1110**	**$10.61**	**$9.77**	**$1.84**	**$0.27**			**$1.84**	**$0.27**			**$2.18**	**$0.37**			**$2.91**	**$0.45**			**$3.53**	**$0.53**		

All dollars are in millions

Union Gas has withdrawn Walpole Isalnd from the application

Table 8
Proposed Community Expansion Projects

					As Filed				**60 Months Term TES/ITE**			
Community	**Maximum Potential Customers**	**Forecast Customers**	**Capital Cost**		**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**	**Contributions (NPV)**		**TES/ITE Period (Months)**	**PI**
			Preferred	**Minimum**	**TES**	**ITE**			**TES**	**ITE**		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1 Milverton	818	526	$4.93	$4.77	$1.01	$0.15	48	0.57	$1.33	$0.19	60	0.64
2 Prince Township	375	242	$2.72	$2.72	$0.22	$0.09	48	0.50	$0.30	$0.11	60	0.53
3 Lambton Shores/ Kettle Point FN	496	281	$2.42	$1.79	$0.51	$0.01	82/48	0.73	$0.57	$0.02	82/60	0.77
4 Moraviantown	70	61	$0.54	$0.49	$0.10	$0.02	48	0.58	$0.12	$0.02	60	0.64
5 **Total**	**1759**	**1110**	**$10.61**	**$9.77**	**$1.84**	**$0.27**			**$2.32**	**$0.34**		

All dollars are in millions

The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pp. 43-45

a) Has Union incorporated any demand side management activity into the determination of the facilities needed to serve the projects? If not, why not? If yes, please describe.

b) Will DSM dollars be available to potential customers in the project areas to ensure that they use the least amount of gas possible? If not, please explain why not. If yes, please provide details of any special arrangements that will be made.

c) Is Union aware of any CDM related money or programs from the IESO that may be available to customers to switch from electricity to natural gas? If yes, what assumptions has Union used in its calculations of the economics of the conversions for customers?

Response:

a) The design day demands for Union South and Union North take into account existing DSM program volume reductions since the design day demands are based on the previous winter's actual daily measured volumes. Any impact of in place DSM programs will be reflected in the actual daily measured volumes. Company forecasts which include, for example, reduction of contract rate customers' volumes due to known energy efficiency changes, are also included in the calculation of forecast design day demand.

   Union does not currently have a method to measure the impact on design day demands attributable to DSM programs. Please also see the response at Exhibit B.Energy Probe.6 e).

b) Please see the response at Exhibit B.Energy Probe.6 c).

c) Please see the response at Exhibit B.Energy Probe.6 a).

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix D

Please provide a revised Appendix D table that shows for each of the 30 projects which Union has identified it could proceed with if its proposal is accepted by the Board to show the following:

a) the total TES amount forecasted to be collected;
b) the total ITE amount forecasted to be collected; and
c) the amount forecasted to be collected from existing customers to make up for the shortfall in the PI.

Please provide the requested amounts in both discounted and undiscounted amounts.

Response:

a-c) As noted in a number of other responses, Exhibit A, Tab 1, Appendix D provides a high level assessment for Projects other than those that Union is seeking approval for in this Application. The information provided in Attachment 1 represents approximate values.

This question asks for the amount forecast to be collected from existing customers to make up for the shortfall in the P.I. Since the P.I is based on discounted values, only discounted values have been provided in this response. Discounted values are based on 5.10% per year, which is Union's after tax weighted average cost of capital ("WACC") used in the discounted cash flow analysis.

Filed 2015-12-09
EB-2015-0179
Exhibit B. LPMA.16
Attachment 1

Opportunity Assessment Summary

		Discounted		
	Community Name	TES to be Collected (millions)	ITE to be Collected (millions)	Amount to be Collected from Existing Customers (millions)
Line	($ millions)	(a)	(b)	(c)
1	Milverton	1.0	0.2	2.0
2	Prince Township, Sault Ste Marie	0.2	0.1	1.3
3	Lambton Shores, Kettle Point First Nation	0.5	0.0	0.5
4	~~Walpole Island First Nation- main commercial area~~			
5	Moraviantown First Nation- main commercial area	0.1	0.0	0.2
6	Lagoon City (Orillia)	1.3	0.4	6.2
7	Hidden Valley/Huntsville	0.1	0.0	0.3
8	Santa's Village/Beaumont Dr, Bracebridge	0.1	0.0	0.4
9	Canal, Gravenhurst	0.1	0.0	0.6
10	Northshore Rd / Peninsula Rd North Bay	0.2	0.1	1.3
11	Hornby	0.2	0.1	0.7
12	Oneida First Nation	0.2	0.1	1.3
13	Auburn	0.1	0.0	0.3
14	Cedar Springs	0.1	0.0	0.5
15	Astorville	0.3	0.1	2.1
16	~~***Brenman Line, Servern Twp (Gravenhurst)~~			
17	Nipissing First Nation / Jocko Point	0.3	0.1	2.3
18	~~***Munsee Delaware First Nation~~			
19	Chippewa of the Thames First Nation- phase 3 & 4	0.1	0.0	0.4
20	Sheffield	0.1	0.0	0.5
21	Turkey Point	0.6	0.2	2.1
22	Rockton	0.1	0.0	0.5
23	Chippewas of the Saugeen	0.1	0.0	0.5
24	Washago	0.5	0.2	2.4
25	E Floral (T Bay area)	0.1	0.1	0.6
26	Haldimand Shores	0.2	0.1	1.1
27	Latchford, Tri Town	0.3	0.2	1.4
28	Belwood	0.9	0.4	3.4
29	Kincardine. Tiverton, Paisley, Chesley	15.9	1.6	39.3
30	~~***Little Longlac~~			
31	Swiss Meadow	0.2	0.1	0.6
32	Boblo Island	0.5	0.2	1.6
33	Village of Warwick	0.3	0.1	0.9
	TOTALS- All Projects	**$24.7**	**$4.6**	**$75.5**

*** Project does not meet the definition of a Community Expansion Project so would not be eligible for a reduced P.I. without additional project scope.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix H

a) Other than the being related to a community expansion project, what are the differences between the TCS and the TES, as defined on page 2?

b) Please explain what Union means by a district rolling project PI as used on page 3.

Response:

a) Please see the response at Exhibit B.Energy Probe.17 a).

b) The District Rolling P.I. is calculated in the same way the Union North, Union South, and Corporate Rolling P.I.s are calculated with the exception the District Rolling P.I. includes only projects that are completed within each District. It is used as a local management tool.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix H

At page 3 the guidelines state that where the cost of proposed projects exceeds the capital available in a particular year or would result in failure to meet minimum portfolio performance (PI) targets, Union will proceed with the most profitable projects.

a) Does this mean that community expansion projects are ranked lower than profitable projects with regards to access to limited capital? Please explain fully.

b) Could the spending on community expansion projects result in delays in attaching customers in more profitable projects? Please explain fully.

Response:

a) Yes. Union would in cases of capital limitations proceed with more profitable Projects first.

b) No, Union does not expect that Community Expansion Projects would result in delays in attaching more profitable projects. Union intends to work with its contractors in order to ensure adequate resources are available for construction of the Projects. This resource planning will be a consideration in which Projects can be scheduled each year, as noted in Exhibit A, Tab 1, p. 35, lines 15 to 19.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix J

a) Does Union expect to start all 30 potential community expansion projects in 2016? If not, please provide a revised version of Appendix J that shows the current expectations of when projects will be placed into service.

b) Please provide a version of Appendix J that reflects only projects that would achieve a PI of:

i) 0.5,
ii) 0.6, and
iii) 0.7

assuming the TES and ITE but no provincial loans or grants.

c) Please provide a version of Appendix J that reflects Union's proposals but excludes the following projects from the 30 potential community expansion projects:

i) the largest capital expenditure project; and
ii) the largest two capital expenditure projects.

Response:

a) Please see the response at Exhibit B.South Bruce.5 a).

b) Please see Attachments 1 through 3.

c) Please see Attachments 4 and 5.

UNION GAS LIMITED
Revenue Requirement of the Community Expansion Projects that Achieve a P.I. of 0.5
(Including TES and ITE)

Line No.	Particulars ($000's)	2016	2017	2018
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	39,543	3,141	1,188
2	Average Investment	12,918	39,515	40,880
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	12	57	115
4	Depreciation Expense (2)	530	1,099	1,154
5	Property Taxes	136	409	409
6	Total Operating Expenses	678	1,565	1,678
7	Required Return (5.77% x line 2) (3)	746	2,282	2,361
	Income Taxes:			
8	Income Taxes - Equity Return (4)	150	457	473
9	Income Taxes - Utility Timing Differences (5)	(240)	(466)	(441)
10	Total Income Taxes	(90)	(9)	32
11	Total Revenue Requirement (line 6 + line 7 + line 10)	1,334	3,838	4,070
12	Incremental Revenue (6)	87	417	826
13	Net Revenue Requirement (line 11 - line 12)	1,247	3,421	3,244

Notes:
(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$40.880 million x 64% x 4.0% = $1.047 million plus
$40.880 million x 36% x 8.93% = $1.314 million for a total of $2.361 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Community Expansion Projects that Achieve a P.I. of 0.6
(Including TES and ITE)

Line No.	Particulars ($000's)	2016	2017	2018
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	26,089	2,391	902
2	Average Investment	8,523	26,174	27,320
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	9	44	89
4	Depreciation Expense (2)	350	730	772
5	Property Taxes	91	273	273
6	Total Operating Expenses	450	1,048	1,134
7	Required Return (5.77% x line 2) (3)	492	1,512	1,578
	Income Taxes:			
8	Income Taxes - Equity Return (4)	99	303	316
9	Income Taxes - Utility Timing Differences (5)	(156)	(310)	(296)
10	Total Income Taxes	(58)	(7)	20
11	Total Revenue Requirement (line 6 + line 7 + line 10)	885	2,552	2,732
12	Incremental Revenue (6)	68	324	635
13	Net Revenue Requirement (line 11 - line 12)	817	2,229	2,096

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$27.320 million x 64% x 4.0% = $0.699 million plus
$27.320 million x 36% x 8.93% = $0.878 million for a total of $1.578 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.

(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the Community Expansion Projects that Achieve a P.I. of 0.7
(Including TES and ITE)

Line No.	Particulars ($000's)	2016	2017	2018
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	20,680	1,988	754
2	Average Investment	6,756	20,779	21,759
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	8	37	75
4	Depreciation Expense (2)	278	580	615
5	Property Taxes	73	219	219
6	Total Operating Expenses	358	836	908
7	Required Return (5.77% x line 2) (3)	390	1,200	1,257
	Income Taxes:			
8	Income Taxes - Equity Return (4)	78	240	252
9	Income Taxes - Utility Timing Differences (5)	(124)	(246)	(236)
10	Total Income Taxes	(45)	(6)	16
11	Total Revenue Requirement (line 6 + line 7 + line 10)	703	2,031	2,181
12	Incremental Revenue (6)	164	308	558
13	Net Revenue Requirement (line 11 - line 12)	539	1,722	1,622

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$21.759 million x 64% x 4.0% = $0.557 million plus
$21.759 million x 36% x 8.93% = $0.700 million for a total of $1.257 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.

(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the 29 Potential Community Expansion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project

Line No.	Particulars ($000's)	2016 (a)	2017 (b)	2018 (c)
	Rate Base Investment			
1	Capital Expenditures	57,683	3,867	1,459
2	Average Investment	18,843	57,405	58,841
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	14	70	142
4	Depreciation Expense (2)	774	1,598	1,664
5	Property Taxes	197	590	590
6	Total Operating Expenses	986	2,258	2,397
7	Required Return (5.77% x line 2) (3)	1,088	3,315	3,398
	Income Taxes:			
8	Income Taxes - Equity Return (4)	218	664	681
9	Income Taxes - Utility Timing Differences (5)	(348)	(675)	(633)
10	Total Income Taxes	(130)	(10)	48
11	Total Revenue Requirement (line 6 + line 7 + line 10)	1,943	5,563	5,843
12	Incremental Revenue (6)	108	517	1,026
13	Net Revenue Requirement (line 11 - line 12)	1,836	5,046	4,817

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$58.841 million x 64% x 4.0% = $1.506 million plus
$58.841 million x 36% x 8.93% = $1.892 million for a total of $3.398 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.

(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED
Revenue Requirement of the 29 Potential Community Expansion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley and Lagoon City (Orillia) Projects

Line No.	Particulars ($000's)	2016	2017	2018
		(a)	(b)	(c)
	Rate Base Investment			
1	Capital Expenditures	47,804	2,443	924
2	Average Investment	15,615	47,323	47,926
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	11	52	105
4	Depreciation Expense (2)	642	1,315	1,358
5	Property Taxes	164	492	492
6	Total Operating Expenses	817	1,859	1,954
7	Required Return (5.77% x line 2) (3)	902	2,733	2,768
	Income Taxes:			
8	Income Taxes - Equity Return (4)	181	548	555
9	Income Taxes - Utility Timing Differences (5)	(289)	(554)	(513)
10	Total Income Taxes	(108)	(6)	41
11	Total Revenue Requirement (line 6 + line 7 + line 10)	1,610	4,585	4,763
12	Incremental Revenue (6)	78	372	733
13	Net Revenue Requirement (line 11 - line 12)	1,532	4,213	4,030

Notes:

(1) Operating and Maintenance expenses include distribution expenses associated with attaching a new customer.
(2) Depreciation expense at 2013 Board-approved depreciation rates.
(3) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 x 0.04 + 0.36 x 0.0893).

The 2018 required return calculation is as follows:
$47.926 million x 64% x 4.0% = $1.227 million plus
$47.926 million x 36% x 8.93% = $1.541 million for a total of $2.768 million.

(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(6) Incremental revenue associated with forecast customer attachments based on an average Union North and Union South residential and commercial customer.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix K

Please provide a version of Appendix K for each of the requested scenarios in parts (b) and (c) of LPMA.19.

Response:

Please see Attachments 1 through 3 for the 2018 cost allocation of the scenarios requested in Exhibit B.LPMA.19 b) and Attachments 4 and 5 for the 2018 cost allocation of the scenarios requested in Exhibit B.LPMA.19 c).

UNION GAS LIMITED
2018 Cost Allocation of the Community Expansion Projects that Achieve a P.I. of 0.5

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	1,102	(393)	(144)	565
2	Rate M2	202	(72)	(25)	105
3	Rate M4	56	(20)	(7)	29
4	Rate M5	78	(28)	(6)	44
5	Rate M7	14	(5)	(2)	7
6	Rate M9	0	(0)	(0)	(0)
7	Rate M10	0	(0)	(0)	0
8	Rate T1	39	(14)	(5)	20
9	Rate T2	54	(19)	(22)	13
10	Rate T3	(0)	0	(2)	(2)
11	Subtotal - Union South	1,544	(551)	(213)	780
12	Excess Utility Space	(3)	1	(1)	(2)
13	Rate C1	(1)	0	(1)	(2)
14	Rate M12	(49)	17	(80)	(111)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(52)	19	(82)	(116)
18	Rate 01	1,420	(507)	(61)	853
19	Rate 10	398	(142)	(10)	246
20	Rate 20	314	(112)	(7)	195
21	Rate 100	358	(128)	(6)	224
22	Rate 25	89	(32)	(2)	55
23	Subtotal - Union North	2,578	(920)	(85)	1,574
24	In-franchise	4,123	(1,471)	(298)	2,353
25	Ex-franchise	(52)	19	(82)	(116)
26	Total	4,070	(1,452)	(380)	2,238

Notes:
(1) 2018 project costs associated with the community expansion projects that achieve a P.I. of 0.5 including the TES and ITE but no provincial loans or grants, as per Exhibit B.LPMA.19, Attachment 1, p.1, column (c).
(2) TES credit allocated to rate classes in proportion to column (a).
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED
2018 Cost Allocation of the Community Expansion Projects that Achieve a P.I. of 0.6

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	604	(245)	(92)	267
2	Rate M2	110	(44)	(16)	49
3	Rate M4	30	(12)	(4)	14
4	Rate M5	43	(17)	(4)	22
5	Rate M7	8	(3)	(1)	3
6	Rate M9	(0)	0	(0)	(0)
7	Rate M10	0	(0)	(0)	0
8	Rate T1	21	(9)	(3)	9
9	Rate T2	29	(12)	(14)	3
10	Rate T3	(0)	0	(1)	(2)
11	Subtotal - Union South	844	(342)	(137)	365
12	Excess Utility Space	(2)	1	(0)	(2)
13	Rate C1	(1)	0	(1)	(1)
14	Rate M12	(33)	13	(51)	(71)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(36)	15	(53)	(74)
18	Rate 01	1,031	(417)	(39)	575
19	Rate 10	285	(115)	(6)	163
20	Rate 20	249	(101)	(4)	144
21	Rate 100	288	(117)	(4)	168
22	Rate 25	72	(29)	(1)	41
23	Subtotal - Union North	1,924	(779)	(55)	1,090
24	In-franchise	2,768	(1,121)	(191)	1,456
25	Ex-franchise	(36)	15	(53)	(74)
26	Total	2,732	(1,106)	(244)	1,382

Notes:
(1) 2018 project costs associated with the community expansion projects that achieve a P.I. of 0.6 including the TES and ITE but no provincial loans or grants, as per Exhibit B.LPMA.19, Attachment 1, p.2, column (c).
(2) TES credit allocated to rate classes in proportion to column (a).
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED
2018 Cost Allocation of the Community Expansion Projects that Achieve a P.I. of 0.7

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	421	(180)	(72)	169
2	Rate M2	78	(34)	(12)	32
3	Rate M4	22	(9)	(3)	9
4	Rate M5	31	(13)	(3)	15
5	Rate M7	6	(2)	(1)	2
6	Rate M9	(0)	0	(0)	(0)
7	Rate M10	0	(0)	(0)	(0)
8	Rate T1	15	(7)	(3)	6
9	Rate T2	20	(9)	(11)	1
10	Rate T3	(0)	0	(1)	(1)
11	Subtotal - Union South	592	(254)	(106)	232
12	Excess Utility Space	(1)	1	(0)	(1)
13	Rate C1	(1)	0	(0)	(1)
14	Rate M12	(27)	11	(40)	(55)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(29)	12	(41)	(57)
18	Rate 01	823	(352)	(30)	440
19	Rate 10	228	(97)	(5)	125
20	Rate 20	230	(98)	(3)	128
21	Rate 100	271	(116)	(3)	152
22	Rate 25	66	(28)	(1)	37
23	Subtotal - Union North	1,617	(692)	(42)	883
24	In-franchise	2,209	(945)	(149)	1,115
25	Ex-franchise	(29)	12	(41)	(57)
26	Total	2,181	(933)	(190)	1,058

Notes:
(1) 2018 project costs associated with the community expansion projects that achieve a P.I. of 0.7 including the TES and ITE but no provincial loans or grants, as per Exhibit B.LPMA.19, Attachment 1, p.3, column (c).
(2) TES credit allocated to rate classes in proportion to column (a)
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED
2018 Cost Allocation of the 29 Potential Community Expansion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	1,785	(544)	(212)	1,029
2	Rate M2	329	(100)	(37)	192
3	Rate M4	91	(28)	(10)	53
4	Rate M5	127	(39)	(9)	79
5	Rate M7	23	(7)	(3)	13
6	Rate M9	0	(0)	(0)	(0)
7	Rate M10	0	(0)	(0)	0
8	Rate T1	63	(19)	(8)	36
9	Rate T2	88	(27)	(32)	29
10	Rate T3	(0)	0	(3)	(4)
11	Subtotal - Union South	2,504	(763)	(315)	1,426
12	Excess Utility Space	(4)	1	(1)	(4)
13	Rate C1	(2)	0	(1)	(3)
14	Rate M12	(67)	21	(118)	(165)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(73)	22	(121)	(172)
18	Rate 01	1,866	(568)	(89)	1,208
19	Rate 10	543	(165)	(14)	363
20	Rate 20	414	(126)	(10)	278
21	Rate 100	474	(144)	(9)	321
22	Rate 25	114	(35)	(3)	77
23	Subtotal - Union North	3,412	(1,039)	(125)	2,247
24	In-franchise	5,916	(1,802)	(440)	3,674
25	Ex-franchise	(73)	22	(121)	(172)
26	Total	5,843	(1,780)	(562)	3,502

Notes:
(1) 2018 project costs associated with the 29 community expansion projects excluding the Kincardine, Tiverton, Paisley, Chesley Project, as per Exhibit B.LPMA.19, Attachment 2, p.1, column (c).
(2) TES credit allocated to rate classes in proportion to column (a).
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED
2018 Cost Allocation of the 29 Potential Community Expansion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley and Lagoon City (Orillia) Projects

Line No.	Particulars ($000's)	2018 Project Costs (1)	TES (2)	ITE (3)	Total
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	1,922	(571)	(175)	1,176
2	Rate M2	349	(104)	(30)	215
3	Rate M4	96	(28)	(8)	59
4	Rate M5	133	(40)	(7)	86
5	Rate M7	24	(7)	(3)	14
6	Rate M9	0	(0)	(0)	(0)
7	Rate M10	0	(0)	(0)	0
8	Rate T1	66	(20)	(6)	40
9	Rate T2	95	(28)	(27)	40
10	Rate T3	0	(0)	(3)	(3)
11	Subtotal - Union South	2,686	(798)	(260)	1,628
12	Excess Utility Space	(3)	1	(1)	(3)
13	Rate C1	(1)	0	(1)	(2)
14	Rate M12	(53)	16	(97)	(134)
15	Rate M13	(0)	0	(0)	(0)
16	Rate M16	(0)	0	(0)	(0)
17	Subtotal - Ex-franchise	(57)	17	(100)	(140)
18	Rate 01	1,187	(353)	(74)	761
19	Rate 10	366	(109)	(12)	245
20	Rate 20	242	(72)	(8)	161
21	Rate 100	275	(82)	(7)	186
22	Rate 25	64	(19)	(2)	42
23	Subtotal - Union North	2,133	(634)	(103)	1,396
24	In-franchise	4,820	(1,432)	(363)	3,025
25	Ex-franchise	(57)	17	(100)	(140)
26	Total	4,763	(1,416)	(463)	2,885

Notes:
(1) 2018 project costs associated with the 29 community expansion projects excluding the Kincardine, Tiverton, Paisley, Chesley and Lagoon City (Orillia) Projects, as per Exhibit B.LPMA.19, Attachment 2, p.2, column (c).
(2) TES credit allocated to rate classes in proportion to column (a)
(3) ITE contributions allocated to rate classes in proportion to 2013 Board-approved property taxes, as per EB-2011-0210, Updated, Exhibit G3, Tab 2, Schedule 2.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix K

What is the basis for the allocation shown in column (a)?

Response:

The allocation of the 2018 project costs provided at Exhibit A, Tab 1, Appendix K, Updated, column (a) is based on Union's 2013 Board-approved cost allocation methodologies. To allocate the project costs to rate classes, Union added the 2018 revenue requirement associated with the potential Community Expansion Projects to Union's 2013 Board-approved cost allocation study (updated per EB-2013-0365).

The revenue requirement of the potential Community Expansion Projects includes the return and depreciation expense associated with distribution rate base, distribution O&M expenses, income taxes and property taxes, as provided at Exhibit A, Tab 1, Appendix J, Updated.

Distribution rate base and distribution O&M expenses are classified as demand and customer-related costs. Union's Board-approved allocation of distribution demand costs to Union South in-franchise rate classes is based on the design day demands of firm and interruptible customers served by Union's distribution facilities. Union's Board-approved allocation of distribution demand costs to Union North in-franchise rate classes is based on peak day or peak day and average day demands. Union's Board-approved allocation of distribution customer-related costs involve several methodologies based on service and station replacement costs, service call times and average number of customers. Union's Board-approved cost allocation of income taxes is in proportion to rate base and property taxes is in proportion to property tax expense detail.

In addition, adding the Community Expansion Program revenue requirement to Union's 2013 Board-approved cost allocation study (updated per EB-2013-0365) results in the re-allocation of indirect costs (general plant, administrative and general expenses, and general operations and engineering costs). Specifically, by adding the rate base and operating costs associated with the Community Expansion Projects as distribution costs to the 2013 Board-approved cost allocation study, the cost components that are functionalized based on rate base and O&M are re-allocated from storage and transmission functional classifications to the distribution functional classification.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Appendix L & M

a) Please provide a version of each of Appendix L and M for each of the requested scenarios in parts (b) and (c) of LPMA.19.

b) Please show the calculation of the rate impacts for a small, medium and large M2 customer and a small M4 customer using each of the scenarios in parts (b) and (c) of LPMA.19, along with the impacts from Union's proposal.

Response:

a) Please see Attachments 1 through 5 for an updated version of each of Appendix L and M for each of the requested scenarios requested in parts b) and c) of Exhibit B.LPMA.19

b) Please see Attachments 6 through 10 for rate impacts of small, medium, and large Rate M2 customers and a small Rate M4 customer for each of the scenarios requested in parts b) and c) of Exhibit B.LPMA.19.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.03	0.71	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.30	(0.01)	
5	Total Delivery Charge	349.64	350.34	0.70	0.2%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.74	0.70	0.1%
10	Impacts for Customer Notices - Sales (line 8)			0.70	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.70	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.63	2.35	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	449.63	2.35	0.5%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.02)	
18	Subtotal	268.02	268.00	(0.02)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.26	(0.02)	
21	Total Bill (line 13 + line 18)	989.55	991.89	2.34	0.2%
22	Impacts for Customer Notices - Sales (line 19)			2.34	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			2.34	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.03	0.71	
3	Delivery Price Adjustment	-	(0.40)	(0.40)	
4	Storage Services	16.32	16.30	(0.01)	
5	Total Delivery Charge	349.64	349.93	0.30	0.1%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.33	0.30	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.30	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.30	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.63	2.35	
14	Delivery Price Adjustment	-	(1.34)	(1.34)	
15	Total Delivery Charge	447.28	448.29	1.02	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.02)	
18	Subtotal	268.02	268.00	(0.02)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.26	(0.02)	
21	Total Bill (line 13 + line 18)	989.55	990.55	1.00	0.1%
22	Impacts for Customer Notices - Sales (line 19)			1.00	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.00	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.66	0.34	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.31	(0.01)	
5	Total Delivery Charge	349.64	349.96	0.33	0.1%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.37	0.33	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.33	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.33	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.12	1.84	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	449.12	1.84	0.4%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	991.39	1.83	0.2%
22	Impacts for Customer Notices - Sales (line 19)			1.83	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.83	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.66	0.34	
3	Delivery Price Adjustment	-	(0.25)	(0.25)	
4	Storage Services	16.32	16.31	(0.01)	
5	Total Delivery Charge	349.64	349.71	0.08	0.0%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.11	0.08	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.08	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.08	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.12	1.84	
14	Delivery Price Adjustment	-	(1.08)	(1.08)	
15	Total Delivery Charge	447.28	448.04	0.77	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	990.31	0.75	0.1%
22	Impacts for Customer Notices - Sales (line 19)			0.75	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			0.75	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.53	0.21	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.31	(0.00)	
5	Total Delivery Charge	349.64	349.84	0.21	0.1%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.24	0.21	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.21	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.21	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	196.88	1.60	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	448.88	1.60	0.4%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.58	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	991.15	1.59	0.2%
22	Impacts for Customer Notices - Sales (line 19)			1.59	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.59	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	81.53	0.21	
3	Delivery Price Adjustment	-	(0.19)	(0.19)	
4	Storage Services	16.32	16.31	(0.00)	
5	Total Delivery Charge	349.64	349.65	0.02	0.0%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.06	0.02	0.0%
10	Impacts for Customer Notices - Sales (line 8)			0.02	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.02	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	196.88	1.60	
14	Delivery Price Adjustment	-	(0.90)	(0.90)	
15	Total Delivery Charge	447.28	447.97	0.70	0.2%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.58	(0.01)	
18	Subtotal	268.02	268.01	(0.01)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.27	(0.01)	
21	Total Bill (line 13 + line 18)	989.55	990.24	0.69	0.1%
22	Impacts for Customer Notices - Sales (line 19)			0.69	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			0.69	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.57	1.25	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.30	(0.02)	
5	Total Delivery Charge	349.64	350.87	1.23	0.4%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	708.27	1.23	0.2%
10	Impacts for Customer Notices - Sales (line 8)			1.23	
11	Impacts for Customer Notices - Direct Purchase (line 4)			1.23	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	198.32	3.04	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	450.32	3.04	0.7%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.56	(0.03)	
18	Subtotal	268.02	267.99	(0.03)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.25	(0.03)	
21	Total Bill (line 13 + line 18)	989.55	992.57	3.02	0.3%
22	Impacts for Customer Notices - Sales (line 19)			3.02	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			3.02	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.57	1.25	
3	Delivery Price Adjustment	-	(0.57)	(0.57)	
4	Storage Services	16.32	16.30	(0.02)	
5	Total Delivery Charge	349.64	350.30	0.67	0.2%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.70	0.67	0.1%
10	Impacts for Customer Notices - Sales (line 8)			0.67	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.67	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	198.32	3.04	
14	Delivery Price Adjustment	-	(1.55)	(1.55)	
15	Total Delivery Charge	447.28	448.77	1.49	0.3%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.56	(0.03)	
18	Subtotal	268.02	267.99	(0.03)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.25	(0.03)	
21	Total Bill (line 13 + line 18)	989.55	991.02	1.46	0.1%
22	Impacts for Customer Notices - Sales (line 19)			1.46	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.46	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley and Lagoon City (Orillia) Projects
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.70	1.38	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	16.32	16.30	(0.01)	
5	Total Delivery Charge	349.64	351.01	1.37	0.4%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	708.41	1.37	0.2%
10	Impacts for Customer Notices - Sales (line 8)			1.37	
11	Impacts for Customer Notices - Direct Purchase (line 4)			1.37	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.69	2.42	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	447.28	449.69	2.42	0.5%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.02)	
18	Subtotal	268.02	268.00	(0.02)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.26	(0.02)	
21	Total Bill (line 13 + line 18)	989.55	991.95	2.40	0.2%
22	Impacts for Customer Notices - Sales (line 19)			2.40	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			2.40	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 General Service Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley and Lagoon City (Orillia) Projects
Including TES and ITE Deferral Credits
Annual Consumption of 2,200 m^3

Line No.	Rate M1 - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	252.00	252.00	-	
2	Delivery Commodity Charge	81.32	82.70	1.38	
3	Delivery Price Adjustment	-	(0.56)	(0.56)	
4	Storage Services	16.32	16.30	(0.01)	
5	Total Delivery Charge	349.64	350.45	0.81	0.2%
	Supply Charges				
6	Transportation to Union	83.37	83.37	-	
7	Commodity & Fuel	274.03	274.03	-	
8	Total Gas Supply Charge	357.40	357.40	-	
9	Total Bill (line 4 + line 7)	707.04	707.85	0.81	0.1%
10	Impacts for Customer Notices - Sales (line 8)			0.81	
11	Impacts for Customer Notices - Direct Purchase (line 4)			0.81	

Line No.	Rate 01 Eastern Zone - Particulars	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	252.00	252.00	-	
13	Delivery Commodity Charge	195.28	197.69	2.42	
14	Delivery Price Adjustment	-	(1.01)	(1.01)	
15	Total Delivery Charge	447.28	448.69	1.41	0.3%
	Supply Charges				
16	Transportation to Union	172.43	172.43	0.00	
17	Storage Services	95.59	95.57	(0.02)	
18	Subtotal	268.02	268.00	(0.02)	0.0%
19	Commodity & Fuel	274.26	274.26	-	
20	Total Gas Supply Charge (line 16 + line 17)	542.28	542.26	(0.02)	
21	Total Bill (line 13 + line 18)	989.55	990.94	1.39	0.1%
22	Impacts for Customer Notices - Sales (line 19)			1.39	
23	Impacts for Customer Notices - Direct Purchase (line 13 + line 16)			1.39	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,130.25	13.11	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	385.68	385.44	(0.24)	
5	Total Delivery Charge	3,342.82	3,355.69	12.87	0.4%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,102.99	12.87	0.1%
10	Impacts for Customer Notices - Sales (line 8)			12.87	
11	Impacts for Customer Notices - Direct Purchase (line 4)			12.87	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,389.03	30.54	
14	Delivery Price Adjustment	-	-	-	
15	Storage Services	996.34	995.72	(0.62)	
16	Total Delivery Charge	7,194.83	7,224.75	29.92	0.4%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,405.27	29.92	0.1%
21	Impacts for Customer Notices - Sales (line 8)			29.92	
22	Impacts for Customer Notices - Direct Purchase (line 4)			29.92	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,399.40	45.25	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	1,607.00	1,606.00	(1.00)	
5	Total Delivery Charge	10,801.15	10,845.40	44.25	0.4%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,459.15	44.25	0.1%
10	Impacts for Customer Notices - Sales (line 8)			44.25	
11	Impacts for Customer Notices - Direct Purchase (line 4)			44.25	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,662.40	106.33	
13	Delivery Commodity Charge	9,062.38	9,114.00	51.63	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	36,618.45	36,776.40	157.95	0.4%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,924.53	157.95	0.1%
20	Impacts for Customer Notices - Sales (line 8)			157.95	
21	Impacts for Customer Notices - Direct Purchase (line 4)			157.95	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,130.25	13.11	
3	Delivery Price Adjustment	-	(5.07)	(5.07)	
4	Storage Services	385.68	385.44	(0.24)	
5	Total Delivery Charge	3,342.82	3,350.63	7.81	0.2%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,097.93	7.81	0.1%
10	Impacts for Customer Notices - Sales (line 8)			7.81	
11	Impacts for Customer Notices - Direct Purchase (line 4)			7.81	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,389.03	30.54	
14	Delivery Price Adjustment	-	(13.09)	(13.09)	
15	Storage Services	996.34	995.72	(0.62)	
16	Total Delivery Charge	7,194.83	7,211.65	16.82	0.2%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,392.18	16.82	0.1%
21	Impacts for Customer Notices - Sales (line 8)			16.82	
22	Impacts for Customer Notices - Direct Purchase (line 4)			16.82	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.5
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,399.40	45.25	
3	Delivery Price Adjustment	-	(21.12)	(21.12)	
4	Storage Services	1,607.00	1,606.00	(1.00)	
5	Total Delivery Charge	10,801.15	10,824.28	23.13	0.2%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,438.03	23.13	0.0%
10	Impacts for Customer Notices - Sales (line 8)			23.13	
11	Impacts for Customer Notices - Direct Purchase (line 4)			23.13	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,662.40	106.33	
13	Delivery Commodity Charge	9,062.38	9,114.00	51.63	
14	Delivery Price Adjustment	-	(61.61)	(61.61)	
15	Total Delivery Charge	36,618.45	36,714.79	96.34	0.3%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,862.91	96.34	0.1%
20	Impacts for Customer Notices - Sales (line 8)			96.34	
21	Impacts for Customer Notices - Direct Purchase (line 4)			96.34	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,124.31	7.17	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	385.68	385.50	(0.18)	
5	Total Delivery Charge	3,342.82	3,349.81	6.99	0.2%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,097.11	6.99	0.1%
10	Impacts for Customer Notices - Sales (line 8)			6.99	
11	Impacts for Customer Notices - Direct Purchase (line 4)			6.99	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,375.12	16.63	
14	Delivery Price Adjustment	-	-	-	
15	Storage Services	996.34	995.88	(0.47)	
16	Total Delivery Charge	7,194.83	7,210.99	16.16	0.2%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,391.52	16.16	0.0%
21	Impacts for Customer Notices - Sales (line 8)			16.16	
22	Impacts for Customer Notices - Direct Purchase (line 4)			16.16	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,378.75	24.60	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	1,607.00	1,606.25	(0.75)	
5	Total Delivery Charge	10,801.15	10,825.00	23.85	0.2%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,438.75	23.85	0.0%
10	Impacts for Customer Notices - Sales (line 8)			23.85	
11	Impacts for Customer Notices - Direct Purchase (line 4)			23.85	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,613.90	57.83	
13	Delivery Commodity Charge	9,062.38	9,090.38	28.00	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	36,618.45	36,704.28	85.83	0.2%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,852.40	85.83	0.0%
20	Impacts for Customer Notices - Sales (line 8)			85.83	
21	Impacts for Customer Notices - Direct Purchase (line 4)			85.83	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,124.31	7.17	
3	Delivery Price Adjustment	-	(3.15)	(3.15)	
4	Storage Services	385.68	385.50	(0.18)	
5	Total Delivery Charge	3,342.82	3,346.66	3.84	0.1%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,093.96	3.84	0.0%
10	Impacts for Customer Notices - Sales (line 8)			3.84	
11	Impacts for Customer Notices - Direct Purchase (line 4)			3.84	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,375.12	16.63	
14	Delivery Price Adjustment	-	(8.15)	(8.15)	
15	Storage Services	996.34	995.88	(0.47)	
16	Total Delivery Charge	7,194.83	7,202.84	8.01	0.1%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,383.37	8.01	0.0%
21	Impacts for Customer Notices - Sales (line 8)			8.01	
22	Impacts for Customer Notices - Direct Purchase (line 4)			8.01	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.6
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,378.75	24.60	
3	Delivery Price Adjustment	-	(13.14)	(13.14)	
4	Storage Services	1,607.00	1,606.25	(0.75)	
5	Total Delivery Charge	10,801.15	10,811.86	10.71	0.1%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,425.61	10.71	0.0%
10	Impacts for Customer Notices - Sales (line 8)			10.71	
11	Impacts for Customer Notices - Direct Purchase (line 4)			10.71	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,613.90	57.83	
13	Delivery Commodity Charge	9,062.38	9,090.38	28.00	
14	Delivery Price Adjustment	-	(38.42)	(38.42)	
15	Total Delivery Charge	36,618.45	36,665.85	47.41	0.1%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,813.98	47.41	0.0%
20	Impacts for Customer Notices - Sales (line 8)			47.41	
21	Impacts for Customer Notices - Direct Purchase (line 4)			47.41	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,122.21	5.07	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	385.68	385.56	(0.12)	
5	Total Delivery Charge	3,342.82	3,347.77	4.95	0.1%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,095.07	4.95	0.0%
10	Impacts for Customer Notices - Sales (line 8)			4.95	
11	Impacts for Customer Notices - Direct Purchase (line 4)			4.95	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,370.37	11.88	
14	Delivery Price Adjustment	-	-	-	
15	Storage Services	996.34	996.03	(0.31)	
16	Total Delivery Charge	7,194.83	7,206.40	11.57	0.2%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,386.93	11.57	0.0%
21	Impacts for Customer Notices - Sales (line 8)			11.57	
22	Impacts for Customer Notices - Direct Purchase (line 4)			11.57	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,371.81	17.65	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	1,607.00	1,606.50	(0.50)	
5	Total Delivery Charge	10,801.15	10,818.31	17.15	0.2%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,432.06	17.15	0.0%
10	Impacts for Customer Notices - Sales (line 8)			17.15	
11	Impacts for Customer Notices - Direct Purchase (line 4)			17.15	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,597.66	41.59	
13	Delivery Commodity Charge	9,062.38	9,082.50	20.13	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	36,618.45	36,680.16	61.71	0.2%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,828.28	61.71	0.0%
20	Impacts for Customer Notices - Sales (line 8)			61.71	
21	Impacts for Customer Notices - Direct Purchase (line 4)			61.71	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,122.21	5.07	
3	Delivery Price Adjustment	-	(2.40)	(2.40)	
4	Storage Services	385.68	385.56	(0.12)	
5	Total Delivery Charge	3,342.82	3,345.37	2.55	0.1%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,092.67	2.55	0.0%
10	Impacts for Customer Notices - Sales (line 8)			2.55	
11	Impacts for Customer Notices - Direct Purchase (line 4)			2.55	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,370.37	11.88	
14	Delivery Price Adjustment	-	(6.21)	(6.21)	
15	Storage Services	996.34	996.03	(0.31)	
16	Total Delivery Charge	7,194.83	7,200.19	5.37	0.1%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,380.72	5.37	0.0%
21	Impacts for Customer Notices - Sales (line 8)			5.37	
22	Impacts for Customer Notices - Direct Purchase (line 4)			5.37	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the Community Expansion Projects that Achieve a P.I. of 0.7
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,371.81	17.65	
3	Delivery Price Adjustment	-	(10.01)	(10.01)	
4	Storage Services	1,607.00	1,606.50	(0.50)	
5	Total Delivery Charge	10,801.15	10,808.30	7.14	0.1%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,422.05	7.14	0.0%
10	Impacts for Customer Notices - Sales (line 8)			7.14	
11	Impacts for Customer Notices - Direct Purchase (line 4)			7.14	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,597.66	41.59	
13	Delivery Commodity Charge	9,062.38	9,082.50	20.13	
14	Delivery Price Adjustment	-	(29.39)	(29.39)	
15	Total Delivery Charge	36,618.45	36,650.77	32.32	0.1%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,798.89	32.32	0.0%
20	Impacts for Customer Notices - Sales (line 8)			32.32	
21	Impacts for Customer Notices - Direct Purchase (line 4)			32.32	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,138.33	21.19	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	385.68	385.32	(0.36)	
5	Total Delivery Charge	3,342.82	3,363.65	20.83	0.6%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,110.95	20.83	0.2%
10	Impacts for Customer Notices - Sales (line 8)			20.83	
11	Impacts for Customer Notices - Direct Purchase (line 4)			20.83	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,407.91	49.42	
14	Delivery Price Adjustment	-	-	-	
15	Storage Services	996.34	995.41	(0.93)	
16	Total Delivery Charge	7,194.83	7,243.32	48.49	0.7%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,423.85	48.49	0.1%
21	Impacts for Customer Notices - Sales (line 8)			48.49	
22	Impacts for Customer Notices - Direct Purchase (line 4)			48.49	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,427.51	73.35	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	1,607.00	1,605.50	(1.50)	
5	Total Delivery Charge	10,801.15	10,873.01	71.85	0.7%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,486.76	71.85	0.1%
10	Impacts for Customer Notices - Sales (line 8)			71.85	
11	Impacts for Customer Notices - Direct Purchase (line 4)			71.85	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,728.87	172.80	
13	Delivery Commodity Charge	9,062.38	9,146.38	84.00	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	36,618.45	36,875.25	256.80	0.7%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	179,023.37	256.80	0.1%
20	Impacts for Customer Notices - Sales (line 8)			256.80	
21	Impacts for Customer Notices - Direct Purchase (line 4)			256.80	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,138.33	21.19	
3	Delivery Price Adjustment	-	(7.15)	(7.15)	
4	Storage Services	385.68	385.32	(0.36)	
5	Total Delivery Charge	3,342.82	3,356.50	13.68	0.4%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,103.80	13.68	0.1%
10	Impacts for Customer Notices - Sales (line 8)			13.68	
11	Impacts for Customer Notices - Direct Purchase (line 4)			13.68	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,407.91	49.42	
14	Delivery Price Adjustment	-	(18.48)	(18.48)	
15	Storage Services	996.34	995.41	(0.93)	
16	Total Delivery Charge	7,194.83	7,224.84	30.01	0.4%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,405.36	30.01	0.1%
21	Impacts for Customer Notices - Sales (line 8)			30.01	
22	Impacts for Customer Notices - Direct Purchase (line 4)			30.01	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chesley Project
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,427.51	73.35	
3	Delivery Price Adjustment	-	(29.81)	(29.81)	
4	Storage Services	1,607.00	1,605.50	(1.50)	
5	Total Delivery Charge	10,801.15	10,843.20	42.04	0.4%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,456.95	42.04	0.1%
10	Impacts for Customer Notices - Sales (line 8)			42.04	
11	Impacts for Customer Notices - Direct Purchase (line 4)			42.04	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,728.87	172.80	
13	Delivery Commodity Charge	9,062.38	9,146.38	84.00	
14	Delivery Price Adjustment	-	(86.89)	(86.89)	
15	Total Delivery Charge	36,618.45	36,788.35	169.91	0.5%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,936.48	169.91	0.1%
20	Impacts for Customer Notices - Sales (line 8)			169.91	
21	Impacts for Customer Notices - Direct Purchase (line 4)			169.91	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chelsey and Lagoon City (Orillia) Projects

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,139.63	22.49	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	385.68	385.38	(0.30)	
5	Total Delivery Charge	3,342.82	3,365.01	22.19	0.7%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,112.31	22.19	0.2%
10	Impacts for Customer Notices - Sales (line 8)			22.19	
11	Impacts for Customer Notices - Direct Purchase (line 4)			22.19	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,410.86	52.37	
14	Delivery Price Adjustment	-	-	-	
15	Storage Services	996.34	995.57	(0.77)	
16	Total Delivery Charge	7,194.83	7,246.43	51.60	0.7%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,426.95	51.60	0.2%
21	Impacts for Customer Notices - Sales (line 8)			51.60	
22	Impacts for Customer Notices - Direct Purchase (line 4)			51.60	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chelsey and Lagoon City (Orillia) Projects

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,431.72	77.57	
3	Delivery Price Adjustment	-	-	-	
4	Storage Services	1,607.00	1,605.75	(1.25)	
5	Total Delivery Charge	10,801.15	10,877.47	76.32	0.7%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,491.22	76.32	0.1%
10	Impacts for Customer Notices - Sales (line 8)			76.32	
11	Impacts for Customer Notices - Direct Purchase (line 4)			76.32	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,738.84	182.76	
13	Delivery Commodity Charge	9,062.38	9,150.75	88.38	
14	Delivery Price Adjustment	-	-	-	
15	Total Delivery Charge	36,618.45	36,889.59	271.14	0.7%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	179,037.71	271.14	0.2%
20	Impacts for Customer Notices - Sales (line 8)			271.14	
21	Impacts for Customer Notices - Direct Purchase (line 4)			271.14	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chelsey and Lagoon City (Orillia) Projects
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,117.14	2,139.63	22.49	
3	Delivery Price Adjustment	-	(7.01)	(7.01)	
4	Storage Services	385.68	385.38	(0.30)	
5	Total Delivery Charge	3,342.82	3,358.00	15.18	0.5%
	Supply Charges				
6	Transportation to Union	2,273.70	2,273.70	-	
7	Commodity & Fuel	7,473.60	7,473.60	-	
8	Total Gas Supply Charge	9,747.30	9,747.30	-	
9	Total Bill (line 4 + line 7)	13,090.12	13,105.30	15.18	0.1%
10	Impacts for Customer Notices - Sales (line 8)			15.18	
11	Impacts for Customer Notices - Direct Purchase (line 4)			15.18	

Line No.	Rate M2 - Average	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($) (a)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($) (b)	Bill Impact ($) (c) = (b - a)	Bill Impact (%) (d) = (c / a)
	Delivery Charges				
12	Monthly Charge	840.00	840.00	-	
13	Delivery Commodity Charge	5,358.49	5,410.86	52.37	
14	Delivery Price Adjustment	-	(18.11)	(18.11)	
15	Storage Services	996.34	995.57	(0.77)	
16	Total Delivery Charge	7,194.83	7,228.32	33.49	0.5%
	Supply Charges				
17	Transportation to Union	5,873.73	5,873.73	-	
18	Commodity & Fuel	19,306.80	19,306.80	-	
19	Total Gas Supply Charge	25,180.53	25,180.53	-	
20	Total Bill (line 4 + line 7)	32,375.35	32,408.84	33.49	0.1%
21	Impacts for Customer Notices - Sales (line 8)			33.49	
22	Impacts for Customer Notices - Direct Purchase (line 4)			33.49	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED
2018 Bill Impacts
Rate Impacts of the 29 Potential Community Expanion Projects
Excluding the Kincardine, Tiverton, Paisley, Chelsey and Lagoon City (Orillia) Projects
Including TES and ITE Deferral Credits

Line No.	Rate M2 - Large	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	8,354.15	8,431.72	77.57	
3	Delivery Price Adjustment	-	(29.21)	(29.21)	
4	Storage Services	1,607.00	1,605.75	(1.25)	
5	Total Delivery Charge	10,801.15	10,848.26	47.11	0.4%
	Supply Charges				
6	Transportation to Union	9,473.75	9,473.75	-	
7	Commodity & Fuel	31,140.00	31,140.00	-	
8	Total Gas Supply Charge	40,613.75	40,613.75	-	
9	Total Bill (line 4 + line 7)	51,414.90	51,462.01	47.11	0.1%
10	Impacts for Customer Notices - Sales (line 8)			47.11	
11	Impacts for Customer Notices - Direct Purchase (line 4)			47.11	

Line No.	Rate M4 - Small	EB-2015-0187 Approved 01-Jul-15 Total Bill (1) ($)	EB-2015-0179 Proposed 01-Jan-18 Total Bill ($)	Bill Impact ($)	Bill Impact (%)
		(a)	(b)	(c) = (b - a)	(d) = (c / a)
	Delivery Charges				
12	Monthly Demand Charge	27,556.07	27,738.84	182.76	
13	Delivery Commodity Charge	9,062.38	9,150.75	88.38	
14	Delivery Price Adjustment	-	(84.79)	(84.79)	
15	Total Delivery Charge	36,618.45	36,804.80	186.35	0.5%
	Supply Charges				
16	Transportation to Union	33,158.13	33,158.13	-	
17	Commodity & Fuel	108,990.00	108,990.00	-	
18	Total Gas Supply Charge	142,148.13	142,148.13	-	
19	Total Bill (line 4 + line 7)	178,766.57	178,952.92	186.35	0.1%
20	Impacts for Customer Notices - Sales (line 8)			186.35	
21	Impacts for Customer Notices - Direct Purchase (line 4)			186.35	

Notes:
(1) Calculated as per Appendix A, EB-2015-0187.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section A

a) Please explain the difference in the PI shown in Section A of 0.73 and that shown in Exhibit A, Tab 1, Appendix D of 0.42. Is this difference solely related to the TES and ITE? If not, please explain the difference fully.

b) Section 4.3 of Exhibit A, Tab 1, states that one of the criteria that must be met for a community expansion project is that the municipality agrees to a binding commitment to make an ITE contribution for the estimated TES term of the project. Lambton Shoes did not agree to the ITE. Please explain why this project qualifies at a community expansion project given that it does not meet one the criteria.

Response:

a) The difference in P.I. is attributed to the TES and ITE.

b) Exhibit A, Tab 1, Section 4.3, line 19 sets out criteria that a Project must meet in order to be eligible for the reduced minimum P.I. threshold of 0.4. Note that this section of evidence does not establish eligibility for a Project to be considered a Community Expansion Project. Lambton Shores meets the definition of a Community Expansion Project as filed in Exhibit A, Tab 1, Appendix B, p. 1 and for that reason qualifies as a Community Expansion Project.

   In the case of Lambton Shores, the municipality was not able to agree to an ITE, and for this reason the Lambton Shores component of the combined Kettle and Stony Point First Nations/Lambton Shores Project is being proposed at the previously existing E.B.O. 188 minimum P.I. threshold of 0.8. For the remainder of the Project, the Kettle and Stony Point First Nations has agreed to the ITE, so that part of the Project is being proposed at a lowered P.I of 0.4.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section A, Schedule 7

a) What is the impact on the Stage 1 DCF of updating the general service rates to those proposed by Union effective January 1, 2016?

b) Please provide the calculation of the revenues showing the number of customer attachments, average annual use and rates used for each type of general service customer included in the project. Please provide a live Excel spreadsheet that shows this calculation.

c) What is the impact on the PI if the average annual use varies by 10% from that used in the forecast?

d) Please provide all data used in the derivation of the average use used in the forecasts for each type of general service customer included in the project.

Response:

a) Please see Attachment 1.

b) Union provided an Excel version via email, copying the Board. The file calculates the revenues and volumes for the customer attachments. Should any other interested parties wish to receive the document, please contact Union directly.

c) Please see Attachment 1.

d) The derivation of average use for the residential sector is common to all Projects and included in the spreadsheet reference for b). The commercial loads are Project specific and are based on Union's understanding of the types of businesses. Please see Attachment 2.

Case	Project	Project 1 PI	Project 2 PI	Project 3 PI	Project 4 PI	$ 000's Project 1 NPV	Project 2 NPV	Project 3 NPV	Project 4 NPV
1	As filed (2015 Rates)	0.44	0.57	0.58	0.50	(976)	(2,021)	(208)	(1,332)
2	Case 1 adjusted to Jan 2016 rates	0.46	0.58	0.59	0.50	(951)	(1,955)	(202)	(1,332)
3	Case 1 : 10% less Annual Use	0.39	0.51	0.52	0.44	(1,071)	(2,299)	(238)	(1,474)
4	Case 1: 10% More Annual use	0.50	0.63	0.64	0.55	(881)	(1,742)	(176)	(1,190)

	Project
1	Kettle Point/ Lambton Shores
2	Milverton
3	Moraviantown
4	Prince Township

Union Gas
General Service Residential Estimated Demand Equations
Key Drivers & its coefficients

Driver	Description	Residential South Coefficients Use Equation	Residential South Coefficients Vol Equation	Residential North Coefficients Use Equation	Residential North Coefficients Vol Equation
Hdd_Jan	Total Heating Degree Day for January	1.38	511.33	0.50	131.65
Hdd_Feb	Total Heating Degree Day for February	1.37	489.79	0.47	121.16
Hdd_Mar	Total Heating Degree Day for March	1.38	483.88	0.45	117.22
Hdd_Apr	Total Heating Degree Day for April	1.35	445.72	0.42	112.04
Hdd_May	Total Heating Degree Day for May	1.34	411.84	0.37	105.38
Hdd_Sep	Total Heating Degree Day for September	1.08	279.76	0.27	76.70
Hdd_Oct	Total Heating Degree Day for October	1.16	331.30	0.33	86.28
Hdd_Nov	Total Heating Degree Day for November	1.27	427.69	0.44	114.77
Hdd_Dec	Total Heating Degree Day for December	1.35	500.83	0.46	120.39
T_Jun	Base load variable for June	23.42	18447.78	-43.50	8683.54
T_Jul	Base load variable for July	20.87	21873.69	-52.10	7419.15
T_Aug	Base load variable for August	15.87	17559.49	-53.86	5957.73
FEI_NS	Energy efficiency Index for heating months (FEI for heating months)			-169.57	
Eff_Fctr	Efficiency weighted by weather (FEI * HDD)	-0.97			
PPH	Persons Per Household for 12 months	16.99			
PPH_S	Persons Per Household for summer months			37.89	
PPH_S1	Persons Per Household for heating months			63.44	
Tbill Lag 2	Total Monthly Bill lagged 2 months	-0.14			
TBillLag12	Total Monthly Bill lagged 12 months			-0.06	
Cust	Number of Customer		0.05		
Custo11	Number of customers up to December 2011 for heating months				0.04
Custsince12	Number of customers since January 2011 for heating months				0.25
AvgP_Lag1	Total Average Price per m3 Lagged 1 month		-129.93		
AvgPr_Lag12	Total Average Price per m3 Lagged 12 month				-56.57

Note on T_variable: the T_variable is icorporated with the intend to capture the base load consumption that happens over the summer months that are not related to variables such as total bill amount, persons living in the household, etc. the T_variable assumes the value of one (1) to which the coefficient is multiplyed by.

Union Gas
General Service
Residential Estimated Demand Equations and assumptions: Union South (*Old Residential Rate M2*)

Residential South USE Equation	Hdd_Jan	Hdd_Feb	Hdd_Mar	Hdd_Apr	Hdd_May	Hdd_Sep	Hdd_Oct	Hdd_Nov	Hdd_Dec	T_Jun	T_Jul	T_Aug	Eff_Fctr	PPH	Lag2 TBill	USE Equation USE Forecast (a) (m3)	Volume Equation USE Forecast (b) (m3)	Combined Equations USE Forecast (c)= (a) + (b) (m3)	DSM Impact (d) (m3)	Residential Old Rate M2 USE Forecast (e)= (c) + (d) (m3)
Coefficients	**1.38**	**1.37**	**1.38**	**1.35**	**1.34**	**1.08**	**1.16**	**1.27**	**1.35**	**23.42**	**20.87**	**15.87**	**- 0.975**	**16.986**	**- 0.140**					
Jan-15															148.75					
Feb-15															130.82					
Mar-15															115.89					
Apr-15															78.02					
May-15															50.55					
Jun-15															40.61					
Jul-15															41.40					
Aug-15															40.13					
Sep-15															42.11					
Oct-15															57.11					
Nov-15															88.73					
Dec-15															129.16					
Jan-16	703	-	-	-	-	-	-	-	-	-	-	-	614.57	2.59	148.75	404.3	398.1	401.2	-1.4	399.8
Feb-16	-	646	-	-	-	-	-	-	-	-	-	-	564.94	2.59	130.82	362.9	355.3	359.1	-1.3	357.8
Mar-16	-	-	535	-	-	-	-	-	-	-	-	-	468.12	2.59	115.89	302.9	297.9	300.4	-1.1	299.3
Apr-16	-	-	-	323	-	-	-	-	-	-	-	-	282.63	2.59	78.02	187.2	183.5	185.3	-0.7	184.7
May-16	-	-	-	-	149	-	-	-	-	-	-	-	130.19	2.59	50.55	99.7	100.7	100.2	-0.4	99.8
Jun-16	-	-	-	-	-	-	-	-	-	1	-	-	-	2.59	40.61	56.4	56.6	56.5	-0.2	56.3
Jul-16	-	-	-	-	-	-	-	-	-	-	1	-	-	2.59	41.40	57.7	57.9	57.8	-0.2	57.6
Aug-16	-	-	-	-	-	-	-	-	-	-	-	1	-	2.59	40.13	54.1	53.8	54.0	-0.2	53.8
Sep-16	-	-	-	-	-	79	-	-	-	-	-	-	69.05	2.59	42.11	56.2	57.9	57.0	-0.2	56.8
Oct-16	-	-	-	-	-	-	253	-	-	-	-	-	221.36	2.59	57.11	115.6	119.2	117.4	-0.4	117.0
Nov-16	-	-	-	-	-	-	-	425	-	-	-	-	371.89	2.59	88.73	213.7	217.6	215.6	-0.8	214.9
Dec-16	-	-	-	-	-	-	-	-	615	-	-	-	538.13	2.59	129.16	339.9	342.2	341.0	-1.2	339.8
																2,250.7	2,240.4	2,245.6	-7.9	2,237.7

Residential South VOLUME Equation	Hdd_Jan	Hdd_Feb	Hdd_Mar	Hdd_Apr	Hdd_May	Hdd_Sep	Hdd_Oct	Hdd_Nov	Hdd_Dec	T_Jun	T_Jul	T_Aug	Cust	Lag1 AvgP	Volume Equation Forecast 10*3m3
Coefficients	**511**	**490**	**484**	**446**	**412**	**280**	**331**	**428**	**501**	**18,448**	**21,874**	**17,559**	**0.046**	**- 130**	
Jan-15														36.12	
Feb-15														37.17	
Mar-15														38.37	
Apr-15														44.10	
May-15														58.09	
Jun-15														74.22	
Jul-15														72.27	
Aug-15														75.48	
Sep-15														70.67	
Oct-15														52.68	
Nov-15														41.85	
Dec-15														37.29	
Jan-16	703	-	-	-	-	-	-	-	-	-	-	-	1,006,554	36.12	400,723
Feb-16	-	646	-	-	-	-	-	-	-	-	-	-	1,007,497	37.17	357,919
Mar-16	-	-	535	-	-	-	-	-	-	-	-	-	1,008,509	38.37	300,391
Apr-16	-	-	-	323	-	-	-	-	-	-	-	-	1,010,078	44.10	185,307
May-16	-	-	-	-	149	-	-	-	-	-	-	-	1,012,597	58.09	101,935
Jun-16	-	-	-	-	-	-	-	-	-	1	-	-	1,012,113	74.22	57,246
Jul-16	-	-	-	-	-	-	-	-	-	-	1	-	1,013,668	72.27	58,648
Aug-16	-	-	-	-	-	-	-	-	-	-	-	1	1,014,136	75.48	54,608
Sep-16	-	-	-	-	-	79	-	-	-	-	-	-	1,015,837	70.67	58,781
Oct-16	-	-	-	-	-	-	253	-	-	-	-	-	1,015,838	52.68	121,116
Nov-16	-	-	-	-	-	-	-	425	-	-	-	-	1,017,809	41.85	221,442
Dec-16	-	-	-	-	-	-	-	-	615	-	-	-	1,020,254	37.29	349,095

Union Gas
General Service
Residential Estimated Demand Equations and assumptions: Union North

Residential North USE Equation

	Hdd_Jan	Hdd_Feb	Hdd_Mar	Hdd_Apr	Hdd_May	Hdd_Sep	Hdd_Oct	Hdd_Nov	Hdd_Dec	T_Jun	T_Jul	T_Aug	FEI_NS	PPH_S	PPH_S1	TBillLag12	USE Equation USE Forecast (a) (m3)	Volume Equation USE Forecast (b) (m3)	Combined Equations USE Forecast (c)= (a) + (b) (m3)	DSM Impact (d) (m3)	Residential Rate 01 USE Forecast (e)= (c) + (d) (m3)
Coefficients	**0.50**	**0.47**	**0.45**	**0.42**	**0.37**	**0.27**	**0.33**	**0.44**	**0.46**	**-43.50**	**-52.10**	**-53.86**	**-169.57**	**37.895**	**63.439**	**-0.065**					
Jan-15																194					
Feb-15																162					
Mar-15																139					
Apr-15																95					
May-15																62					
Jun-15																-					
Jul-15																-					
Aug-15																-					
Sep-15																46					
Oct-15																73					
Nov-15																117					
Dec-15																159					
Jan-16	890	-	-	-	-	-	-	-	-	-	-	-	0.87	-	2.59	194	449	427	438	-1	436.8
Feb-16	-	793	-	-	-	-	-	-	-	-	-	-	0.87	-	2.59	162	376	359	367	-1	366.2
Mar-16	-	-	663	-	-	-	-	-	-	-	-	-	0.87	-	2.59	139	304	300	302	-1	300.7
Apr-16	-	-	-	418	-	-	-	-	-	-	-	-	0.87	-	2.59	95	185	199	192	-1	191.2
May-16	-	-	-	-	218	-	-	-	-	-	-	-	0.87	-	2.59	62	91	120	106	-0	105.5
Jun-16	-	-	-	-	-	-	-	-	-	1	-	-	-	2.59	-	-	55	54	54	-0	54.2
Jul-16	-	-	-	-	-	-	-	-	-	-	1	-	-	2.59	-	-	46	49	48	-0	47.4
Aug-16	-	-	-	-	-	-	-	-	-	-	-	1	-	2.59	-	-	44	44	44	-0	43.8
Sep-16	-	-	-	-	-	144	-	-	-	-	-	-	0.88	-	2.59	46	52	80	66	-0	65.6
Oct-16	-	-	-	-	-	-	345	-	-	-	-	-	0.88	-	2.59	73	126	144	135	-0	134.7
Nov-16	-	-	-	-	-	-	-	538	-	-	-	-	0.88	-	2.59	117	243	248	245	-1	244.7
Dec-16	-	-	-	-	-	-	-	-	772	-	-	-	0.88	-	2.59	159	358	347	353	-1	351.6
																	2,329	2,372	2,350	-8	2,342.4

Residential North VOLUME Equation

	Hdd_Jan	Hdd_Feb	Hdd_Mar	Hdd_Apr	Hdd_May	Hdd_Sep	Hdd_Oct	Hdd_Nov	Hdd_Dec	T_Jun	T_Jul	T_Aug	Custo11	Custsince12	Lag12 AvgPr	Volume Equation Forecast 10*3m3
Coefficients	**132**	**121**	**117**	**112**	**105**	**77**	**86**	**115**	**120**	**8,684**	**7,419**	**5,958**	**0.042**	**0.254**	**-57**	
Jan-15															45.02	
Feb-15															46.39	
Mar-15															47.84	
Apr-15															52.89	
May-15															64.76	
Jun-15															83.55	
Jul-15															89.48	
Aug-15															93.44	
Sep-15															81.74	
Oct-15															58.79	
Nov-15															49.85	
Dec-15															46.56	
Jan-16	890	-	-	-	-	-	-	-	-	-	-	-	286,420	23,415	45.02	132,390
Feb-16	-	793	-	-	-	-	-	-	-	-	-	-	286,420	23,767	46.39	111,373
Mar-16	-	-	663	-	-	-	-	-	-	-	-	-	286,420	23,886	47.84	92,998
Apr-16	-	-	-	418	-	-	-	-	-	-	-	-	286,420	24,203	52.89	61,885
May-16	-	-	-	-	218	-	-	-	-	-	-	-	286,420	24,689	64.76	37,428
Jun-16	-	-	-	-	-	-	-	-	-	1	-	-	311,191	-	83.55	16,875
Jul-16	-	-	-	-	-	-	-	-	-	-	1	-	311,794	-	89.48	15,300
Aug-16	-	-	-	-	-	-	-	-	-	-	-	1	311,890	-	93.44	13,618
Sep-16	-	-	-	-	-	144	-	-	-	-	-	-	286,420	25,843	81.74	24,866
Oct-16	-	-	-	-	-	-	345	-	-	-	-	-	286,420	26,672	58.79	45,085
Nov-16	-	-	-	-	-	-	-	538	-	-	-	-	286,420	27,863	49.85	77,927
Dec-16	-	-	-	-	-	-	-	-	772	-	-	-	286,420	28,985	46.56	109,584

Union Gas
General Service
Estimated use per customer impact
due to DSM activity (m3)

	Residential South	Residential North
Jan-16	-1.41	-1.45
Feb-16	-1.26	-1.22
Mar-16	-1.06	-1.00
Apr-16	-0.65	-0.64
May-16	-0.35	-0.35
Jun-16	-0.20	-0.18
Jul-16	-0.20	-0.16
Aug-16	-0.19	-0.15
Sep-16	-0.20	-0.22
Oct-16	-0.41	-0.45
Nov-16	-0.76	-0.81
Dec-16	-1.20	-1.17

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section B

a) Please explain the difference in the PI shown in Section B of 0.57 and that shown in Exhibit A, Tab 1, Appendix D of 0.32. Is this difference solely related to the TES and ITE? If not, please explain the difference fully.

b) Section 4.3 of Exhibit A, Tab 1, states that one of the criteria that must be met for a community expansion project is that the municipality agrees to a binding commitment to make an ITE contribution for the estimated TES term of the project. Please confirm that municipality has agreed to the ITE. If this cannot be confirmed, please provide details.

Response:

a) The difference in P.I. is attributed to the TES and ITE.

b) The municipality has agreed to the ITE in principle. A signed agreement will be received prior to project execution.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section B, Schedule 7

a) What is the impact on the Stage 1 DCF of updating the general service rates to those proposed by Union effective January 1, 2016?

b) Please provide the calculation of the revenues showing the number of customer attachments, average annual use and rates used for each type of general service customer included in the project. Please provide a live Excel spreadsheet that shows this calculation.

c) What is the impact on the PI if the average annual use varies by 10% from that used in the forecast?

d) Please provide all data used in the derivation of the average use used in the forecasts for each type of general service customer included in the project.

Response:

a-d) Please see the response at Exhibit B.LPMA.24.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section C

a) Please explain the difference in the PI shown in Section C of 0.58 and that shown in Exhibit A, Tab 1, Appendix D of 0.35. Is this difference solely related to the TES and ITE? If not, please explain the difference fully.

b) Section 4.3 of Exhibit A, Tab 1, states that one of the criteria that must be met for a community expansion project is that the municipality agrees to a binding commitment to make an ITE contribution for the estimated TES term of the project. Please confirm that municipality has agreed to the ITE. If this cannot be confirmed, please provide details.

Response:

a) The difference in P.I. is attributed to the TES and ITE.

b) The Moraviantown First Nations community has agreed to the ITE in principle. A signed agreement will be received prior to project execution.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section C, Schedule 6

a) What is the impact on the Stage 1 DCF of updating the general service rates to those proposed by Union effective January 1, 2016?

b) Please provide the calculation of the revenues showing the number of customer attachments, average annual use and rates used for each type of general service customer included in the project. Please provide a live Excel spreadsheet that shows this calculation.

c) What is the impact on the PI if the average annual use varies by 10% from that used in the forecast?

d) Please provide all data used in the derivation of the average use used in the forecasts for each type of general service customer included in the project.

Response:

a-d) Please see the response at Exhibit B.LPMA.24.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section D

a) Please explain the difference in the PI shown in Section D of 0.50 and that shown in Exhibit A, Tab 1, Appendix D of 0.38. Is this difference solely related to the TES and ITE? If not, please explain the difference fully.

b) Section 4.3 of Exhibit A, Tab 1, states that one of the criteria that must be met for a community expansion project is that the municipality agrees to a binding commitment to make an ITE contribution for the estimated TES term of the project. Please confirm that municipality has agreed to the ITE. If this cannot be confirmed, please provide details.

Response:

a) The difference in P.I. is attributed to the TES and ITE.

b) The municipality has agreed to the ITE in principle. A signed agreement will be received prior to project execution.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section D, Schedule 7

a) What is the impact on the Stage 1 DCF of updating the general service rates to those proposed by Union effective January 1, 2016?

b) Please provide the calculation of the revenues showing the number of customer attachments, average annual use and rates used for each type of general service customer included in the project. Please provide a live Excel spreadsheet that shows this calculation.

c) What is the impact on the PI if the average annual use varies by 10% from that used in the forecast?

d) Please provide all data used in the derivation of the average use used in the forecasts for each type of general service customer included in the project.

Response:

a-d) Please see the response at Exhibit B.LPMA.24.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section E

a) Please explain the difference in the PI shown in Section E of 0.40 and that shown in Exhibit A, Tab 1, Appendix D of 0.08. Is this difference solely related to the TES and ITE? If not, please explain the difference fully.

b) Section 4.3 of Exhibit A, Tab 1, states that one of the criteria that must be met for a community expansion project is that the municipality agrees to a binding commitment to make an ITE contribution for the estimated TES term of the project. Please confirm that municipality has agreed to the ITE. If this cannot be confirmed, please provide details.

Response:

a-b) This question relates the Walpole Island First Nations project. The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Section E, Schedule 6

a) What is the impact on the Stage 1 DCF of updating the general service rates to those proposed by Union effective January 1, 2016?

b) Please provide the calculation of the revenues showing the number of customer attachments, average annual use and rates used for each type of general service customer included in the project. Please provide a live Excel spreadsheet that shows this calculation.

c) What is the impact on the PI if the average annual use varies by 10% from that used in the forecast?

d) Please provide all data used in the derivation of the average use used in the forecasts for each type of general service customer included in the project.

Response:

a-d) This question relates the Walpole Island First Nations Project. The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 3

a) Please explain why customers on a small main extension project should be subject to a PI of 1.0 as a result of having less than 50 potential customers, whereas customers in a community expansion project have a required PI of 1.0.

b) If a customer pays an up-front CIAC, how does Union treat that payment for regulatory purposes? For example, is it treated as revenue, subject to earnings sharing, or is treated as a reduction to rate base? Please explain fully.

c) Please explain why the TCS contributions should be treated any differently than CIAC, if that is the result of Union's proposal.

d) Does the ITE apply to the small main extension projects?

Response:

a) Please see the response at Exhibit B.LPMA.5 d) and Exhibit B.VECC.11.

b) An up-front Aid-to-Construction is treated as a deduction to the gross capital cost, and reduces the capital cost included in rate base.

c) Please see the response at Exhibit B.LPMA.1 b). The explanation provided in this response applies to both the TCS and TES.

d) No.

UNION GAS LIMITED

Answer to Interrogatory from
Northern Cross Energy Limited ("NCE")

Reference: Exhibit A, Tab 1, Appendix D

a) If local natural gas storage is available to any of the projects that Union has referenced, would Union consider utilizing that storage to minimize its upstream system reinforcement costs if the overall capital cost of the project was less?

b) If not, why not?

Response:

a-b) Union utilizes storage to meet peak day demand for in-franchise customers. Customers that require additional storage or are external to Union's franchise would hold storage for their own needs. The ability to utilize storage to reduce upstream pipeline capacity would be dependent upon a number of factors, including:

- The cost of upstream pipeline capacity,
- The technical feasibility of the storage,
- The reliability of the storage,
- The system operation requirements, and
- The cost to develop a storage pool or pools (or obtain similar services).

One key system operation requirement is a high degree of confidence in reliability of the storage service. Because Union is expecting to provide distribution service to significant numbers of small firm general service customers, who cannot reasonably be expected to plan for interruptions, the ability to maintain continuity of service is a key factor.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit A, Tab 1, Appendix C, p. 21

Preamble: The final report of the Ontario Energy Board in EBO 188 states:

The Board requires that for all distribution projects, the utilities prepare a display of alternatives (routes and sites) which would show the various trade-offs between customer attachments and environmental, social and financial costs. The Board expects the utilities to prepare common guidelines on how to conduct and document the evaluation of their route selection and to apply these to all expansion projects.

Please indicate whether Union considered liquefied natural gas (LNG) or compressed natural gas (CNG) when it initiated an Opportunity Assessment in 2014 as an alternative to constructing a lateral pipeline to the community in order to determine what mechanisms could be implemented to mitigate financial and environmental barriers to such expansion. Please explain.

Response:

Union considered both LNG and CNG supply scenarios when it conducted the Opportunity Assessment, in addition to the assessment of a CNG supply scenario for the Milverton project which is summarized at Exhibit B.FRPO.1. Union concluded that traditional pipeline supply is more economical and reliable for the Projects proposed in this application.

Union assessed costs to use CNG for several of the larger Community Expansion Projects identified in the Opportunity Assessment and found that the capital costs were approximately 60% of an equivalent traditional pipeline supplied project. However, O&M costs would be over $600 per customer higher each year than what would exist for a traditional pipeline supplied distribution system. Approximately half of this operating cost increase is the cost of transporting the CNG from a compressor to a decanting station located near the edge of each community. A distribution system from the decanting station to each home or business would still require additional regulatory flexibility as proposed by Union in this application, or alternatively, would still require significant levels of Aid to Construction. An assumption made in Union's analysis was that the CNG Compressor would be a regulated asset attributable to the project.

Union also assessed costs to use an LNG supply for the same large Community Expansion Projects and found that the capital costs were approximately 50% of an equivalent traditional pipeline supplied project. However, gas supply and O&M costs would be over $1,500 per customer higher each year than what would exist for a traditional pipeline supplied distribution system. The majority of this incremental cost is a result of the need to liquefy and vapourize the natural gas, along with the cost of transporting the LNG from the liquefaction plant to the vapourization sites. Union's analysis assumed that the liquefaction plant was unregulated.

The incremental annual costs for customers of adopting CNG or LNG supply options would reduce the energy savings of switching to natural gas. This would lead to reduced customer forecasts for the projects, and further deterioration in economic feasibility.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit A, Tab 1, p.35

Preamble: Union can complete approximately 30 projects under its Proposal. If additional funding or project contributions are provided, the potential number of projects could expand beyond this.

Union is seeking approval of five projects in this application. For the remaining 25 that can be serviced under its Proposal, Union will continue to file leave to construct ("LTC") applications for those expansion projects that meet the Board's LTC criteria. The LTC applications will include the requests for approval of the net revenue requirement associated with the projects. Union will also apply for franchise and certificate applications if necessary. For those projects that do not meet the Board's LTC criteria, Union will file an application for approval of the forecast net revenue requirements. Union will then include the approved net revenue requirement impacts for all the approved projects in its next annual rate-setting application.

a) If it can be shown that an alternative, lower cost gas supply solution, such as the use of LNG or CNG, would reduce the gross capital expenditure for certain of the 30 identified as feasible by Union in the Opportunity Assessment, would Union seek to either reduce the proposed Temporary Expansion Surcharge (TES) and Incremental Tax Equivalent (ITE), or maintain these charges but increase the project's PI (and therefore reduce the amount of cross subsidization from other ratepayers)? Please explain your response.

b) If it can be shown that an alternative, lower cost gas supply solution, such as the use of LNG or CNG, would reduce the gross capital expenditure for certain projects identified as not feasible by Union in the Opportunity Assessment, and such reductions in capital expenditures raised the profitability index ("PI") of certain projects to 0.4 or higher after application of the TES and ITE, would Union move to file leave to construct ("LTC") applications for those certain projects provided they meet the Board's LTC criteria. Please explain your response.

Response:

a – b) Capital costs are just one element that needs to be considered when evaluating potential expansion projects. Annual operating costs, gas supply charges, and gas transportation costs can be significantly higher with CNG and LNG distribution models, as noted in Exhibit B.FRPO.1 and Exhibit B.Northeast.1, so they also need to be considered in evaluating expansion project viability. The above question appears to ignore these other very significant components of the annual costs that the customers would have to pay.

Union considered CNG and LNG supply options for the five projects proposed in its application. For these five projects, a traditional pipeline is the lower cost solution and provides higher reliability than CNG or LNG. As noted at Exhibit B.FRPO.1, Union will continue to evaluate CNG and LNG options for future projects.

UNION GAS LIMITED

Answer to Interrogatory from
Northeast Midstream LP ("Northeast")

Reference: Exhibit A, Tab 1, Appendix D, pp. 1-5

Please revise and update the Opportunity Assessment Summary spreadsheet by including the following for each of the 103 communities identified.

a) Column indicated "Potential Customers"
   i. The number that are residential users.
   ii. The number that are commercial users.
   iii. The number that are contract customers.
   iv. Source of information (i.e., Statistics Canada, Municipal Property Assessment Corporation, building count, other means).

b) Column indicated "Forecast Customers"
   i. Expected attachment rate by customer class (residential, commercial, contract).

c) Column indicated "Distance from Source"
   i. Distance of existing facilities requiring system reinforcement.
   ii. Distance of new lateral pipeline from existing facilities to local delivery services.
   iii. Confirm the meaning of blank cells.

d) Column indicated "Annual Volume"
   i. Expected volumes by customer class (residential, commercial, contract).
   ii. Expected peak day / peak hour requirement.

e) Column indicated "Gross Capital Cost"
   i. Capital cost associated with any upstream system reinforcement, including all related materials, labour, engineering, surveys, environmental costs, legal costs, land and permit costs, internal resources, interest during construction, and contingencies (Indirect Costs).
   ii. Capital cost associated with any new lateral pipelines, including all Indirect Costs. For sake of clarity, please consider a new lateral pipeline as a facility where the pipe is either steel (ST) pipe of any size or polyethylene (PE) pipe with a nominal pipe size (NPS) greater than 4", plus meter stations, pressure reduction stations, system valves and the like.
   iii. Capital cost associated with any new local delivery system, including all Indirect Costs. For sake of clarity, please consider local delivery system as a facility with a maximum operating pressure of less than or equal to 99 psig and a NPS less than or equal to 4" PE, plus customer attachments, service meters, and odorization.

f) New Columns

i. Annual cost of third party gas transportation capacity to supply natural gas to the service area.

g) Please provide a working copy of Union's economic feasibility excel spreadsheet for each of the community expansion projects shown in Appendix D, illustrating the economics of the project, cash flows by type, including any CIAC, similar to the schedules provided for the 5 Leave to Construct (LTC) projects (e.g. Exhibit A, Tab 2, Section A, Schedule 6).

Response:

The information requested related to the opportunity list is not available at this time. Exhibit A, Tab 1, Appendix D is intended to indicate the relative magnitude of the opportunities. If Union's proposals are approved by the Board, Union will develop a plan to prioritize and refine information for projects and file information with the Board as required.

The response to this interrogatory is based on four specific projects for which Union is seeking approval[1]. The information requested can be found in the evidence in the relevant sections of Exhibit A, Tab 2. Please also see the response at Exhibit B.Energy Probe.22. Additional notes follow:

a) Please refer to the schedules in Exhibit A, Tab 2. The information is based Union's knowledge of the area and assessment of the potential customers.

b) Please refer to the schedule in Exhibit A, Tab 2

c) Please refer to Exhibit A, Tab 1, Appendix D. The blank cell (Prince Township) indicates either the area is less than 1 km from source or that no high pressure pipeline is required. None of the four projects require reinforcement.

d) i) Please see the response at Exhibit B.LPMA.24 b).

ii) The peak hourly load calculations have only been confirmed for the four Projects submitted. The Project facilities have been designed for the following peak hourly volumes:

Milverton – 2,100m^3/hour
Prince Township – 546 m^3/hour
Kettle Point and Stony Point First Nations/Lambton Shores – 810 m^3/hour
Moraviantown First Nations – 509 m^3/hour

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

e) Please refer to the schedule in Exhibit A, Tab 2. There are no upstream reinforcement costs for the four projects proposed.

f) Union would charge a Union South third party distributor according to its wholesale distribution options Rate M9, Rate M10 or Rate T3 rate schedules. Rate M9 and Rate M10 provide for the purchase of a firm supply of gas for distribution to customers of the third party distributor. Rate T3 provides a wholesale distributor rate option for third party distributors who actively manage their own storage services and require a minimum transportation of 700,000 m^3 of natural gas each year. Union does not have a rate schedule for a similar service in Union North.

g) Union declines to file its economic feasibility excel spreadsheet model (DCF Model). Union's DCF Model is a complex file which is not designed for just this process or Application alone. It requires an experienced user for proper operation. Union has never been required to file an Excel version of its DCF Model in any prior Application.

   The inputs for the DCF Model are clearly identified and listed in the Exhibit A, Tab 2 schedules. Further, Union has provided a working Excel file in the response to Exhibit B.LPMA.24 where the revenue and volumes are calculated in detail. The DCF results for the four projects Union is seeking approval of are found in the relevant Section of Exhibit A, Tab 2.

   The question also asks for the DCF report for each of the other projects listed in Exhibit A, Tab 1, Appendix D. Union will file the DCF report for those projects at the time Union seeks approval for the project.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Federation of Agriculture ("OFA")

Reference: Exhibit A, Tab 1, p. 37, Stage 2, Economic Tests

Preamble: Consideration of the public interest by the Board can be aided by reviewing the results of a Stage 2 economic analysis of the effects of a broader community expansion program.

OEB provides for use of further economic analysis to better understand the public benefits of expansion. This could take the form of both a Stage 2 and a Stage 3 analysis. Stage 2 generally refers to the energy cost savings that potential customers could achieve relative to their existing fuel usage. Stage 3 addresses public interest quantifiable and non-quantifiable benefits associated with a project.

OFA is interested in analysis related to the economic benefits of expansion in rural Ontario, beyond the analysis of cash flows attributed to Union expansion (Stage 1). OFA is interested in the economic benefits attributed to customer cash flows, savings and non-cash benefits to the community and the Province (Stage 2). The initial Union submission included summary Stage 2 benefits and proposed alternate models for determining Stage 2 benefits.

To determine the viability and the potential success of the Union proposal to gain access to rural communities, OFA is interested in any multiplier effect of expansion on the Ontario economy in terms of GDP. The public interest is served through energy efficiencies which natural gas access would provide in rural communities. Union did not submit or quantify any Stage 3 analysis.

a) Is Union aware of and can Union supply detailed Stage 2 analysis of the benefits of expansion and any iteration using the proposed alternative models to determine stage 2 benefits?

b) Can Union supply any third party analysis for consideration related to economic benefits of expansion on the broader Ontario GDP, and related specifically to economic benefits to the Agricultural and Agri-food sector?

c) Can Union provide any third party analysis related to broader economic benefits of Set-Aside programs such as those provided in neighbouring US jurisdictions for Energy Efficiency and Renewable Energy?

Response:

a) Union's evidence did not provide alternative models to determine Stage 2 benefits. Union's evidence at Exhibit A, Tab 1, p. 38, line 16 varied the parameters of the Stage 2 base case calculation to illustrate the impacts of each change noted.

The Stage 2 energy cost savings are derived from the following:

The current energy cost,

Less	The equipment cost to convert to natural gas
Less	The TES for the number of years applicable
Less	The cost of natural gas using Union's current rates

The NPV of the cumulative savings over 40 years is the NPV of the Stage 2 benefits. Please also see the response at Exhibit B.CPA.18.

b) For broader GDP impacts please see the response at Exhibit B.CCC.5, Attachment 1. Union is not aware of any third party reports that relate specifically to the Agricultural or Agri-food sectors.

c) Union is not aware of any third party analysis related to the broader economic benefits of Set-Aside programs.

The Set-Aside Program is an example of how the Environmental Protection Agency ("EPA") in the U.S. is giving States guidance and flexibility in meeting their air quality attainment goals. The Set-Aside Program is consistent with two EPA goals: (1) reducing the total economic cost of meeting the proposed nitrogen oxides (NOx) cap; and, (2) encouraging the adoption of Energy Efficiency/Renewable Energy practices and technologies.

In the U.S., an Energy Efficiency/Renewable Energy Set-Aside is a pool of allowances that come from within a State's NOx budget and is used to award energy efficiency and renewable energy projects that are implemented in the State designed to reduce or displace electricity generation. The EPA recommends that 5% to 15% of a State's NOx budget can be made available for an Energy Efficiency/Renewable Energy Set-Aside. The EPA believes a Set-Aside of this size will deliver significant environmental and economic benefits to a State.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Federation of Agriculture ("OFA")

Reference: Exhibit A, Tab 2, Section A, p. 5 of 12
Lambton Shores, Kettle Point 2011 Telephone survey indicated 64% attachment rate likelihood. Union conservative approach reduced the attachment forecast to 47% (Results will be verified once the 2014 survey is complete).

Exhibit A, Tab 2, Section B, p. 4 of 13
Milverton Customer Attachment Forecast 2014 telephone survey indicated 74% attachment rate likelihood. Union conservative approach reduced the attachment forecast to 59%.

Exhibit A, Tab 2, Section D, p. 4 of 10
Prince Customer Attachment Forecast 2014 telephone survey indicated 84% attachment rate likelihood. Union conservative approach reduced the attachment forecast to 64%.

Exhibit A, Tab A, Appendix D, pp. 1-4 / p. 4, lines 16 -24
General Service customer forecast
Where more detailed information was not available, Union set the customer forecast at 45% of maximum potential customers who would have main installed adjacent to their site. This assumption adjusted downward based on an assumed need for some form of financial contribution from the customers. The forecast was then allocated across residential and commercial/industrial segments based on most recent revenue forecast data (90% residential).

Preamble: OFA believes that the maximum number of rural residents, businesses and farmers deserve access to the same benefits of gas as those who live in urban communities.

a) Can Union provide insight on results found in the Opportunity Assessment Survey? Specifically, had Union used attachment levels similar to survey result levels, or even if Union had used conservatively adjusted survey results, would more General Service customer projects become feasible?

b) If so, with more potential customers and higher PI values, are there any impacts on customer billing or any new billing proposals that could be offered?

c) How would use of survey results and/or conservatively adjusted survey results reposition projects currently categorized as not meeting the definition of Community Expansion Project? Consideration should account for Union past experience with significantly higher commercial customer anticipated attachment rates.

Response:

a) Please see the response at Exhibit B.South Bruce.6 b) where Union provides the impacts of applying the recent survey results to future projects. The impacts of both a more and a less conservative approach (+/- 10 %) to the penetration assumptions used in the development of Exhibit A, Tab 1, Appendix D is provided at Exhibit B.South Bruce.6 c).

b) Union would not adjust its proposals if more potential customers and higher P.I. values were anticipated.

c) A less conservative approach to interpretation of survey results would lead to application of increased customer forecasts, which would improve the economics of all projects. For those made feasible through Union's proposal (with minimum P.I. of 0.4), the TES and ITE terms would be shortened because additional customers would be making the TES payments. For those Projects that still do not meet the minimum P.I. of 0.4, the amount of supplemental Aid-to-Construction required to allow the projects to meet the minimum P.I., despite full 10 year TES and ITE periods, would be lessened for the same reason.

   A more conservative interpretation of survey results would lead to the opposite effects to those noted above.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Producers and Storage Companies ("OPSC")

a) Please provide all of Union Gas' procurement guidelines and policies, which Union uses when it acquires major facilities components, including pipe, meters, flanges and other components used in constructing the proposed system expansions.

b) How does Union Gas ensure cost controls are effective?

Response:

a) Union uses comprehensive competitive sourcing processes to minimize the total cost of ownership and ensure the best possible value. Competitive sourcing includes leveraging the purchasing power of the enterprise and utilizing existing contracts and vendor relationships to drive further savings whenever possible. Union utilizes automation to streamline procurement transactions and drives process efficiency through elimination, simplification, and standardization.

b) In order to ensure effective cost controls, Union utilizes industry standard procurement practices, monitors actual costs vs. forecast costs, and utilizes appropriate approval controls.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Producers and Storage Companies ("OPSC")

a) Please provide and briefly explain Union Gas' criteria for assessing bids and weighting of alternative suppliers of services, with which Union Gas contracts for the construction of pipelines, meter stations and other station facilities.

b) Please describe how these decisions are made and what internal processes are undertaken to ensure prudency of expenditures.

Response:

a-b) Union has alliance contracts for the completion of work related to the construction of distribution facilities. There will not be individual bids for these community projects.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Producers and Storage Companies ("OPSC")

a) Please describe Union Gas' position and approach regarding the selection of bids for the least cost facilities.

b) Is acquisition of construction of least cost facilities in this system expansion proposal a priority for Union Gas, subject to all facilities being CSA and TSSA compatible?

Response:

a-b) Please see the response at Exhibit B.OPSC.2.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Producers and Storage Companies ("OPSC")

a) If a municipality or a customer named in the expansion proposals were to review a facilities plan specific to its area and sought to make changes to the plan, how receptive would Union Gas be to those suggestions?

b) If a municipality or a customer suggested cost-reduction opportunities or alternative facilities locations, would Union Gas consider and evaluate those suggestions?

Response:

a-b) Union has franchise agreements in place with the municipalities where pipeline construction is proposed. Union will follow all provisions in the franchise agreement for the planning, construction and maintenance of the proposed facilities. Union has worked with the municipalities in the development of the project running lines. As such, the municipalities have had input.

UNION GAS LIMITED

Answer to Interrogatory from
Ontario Producers and Storage Companies ("OPSC")

a) Is there an OEB or MNR approved policy or other mechanism by which local Ontario natural gas production is recognized and prioritized in Union Gas' commodity procurement for this community expansion proposal?

b) Please describe the process by which Union Gas determines the quantities of locally produced natural gas that Ontario producers are allowed to supply at a given meter site, or when a request for a new sales point is submitted.

Response:

a) Union is not aware of any such policy or mechanism.

b) Union permits Ontario producers who have contracted with Union under a Gas Purchase Agreement or Rate M13 Local Producer Contract to deliver gas into a producer station connected to Union's existing distribution system. The volume of gas a producer can inject into the distribution system is limited to demand in the local area. Production volumes are also dependent on a producer's ability to deliver gas to the producer station at an adequate pressure such that volumes can enter the distribution system. Ontario producers are also required to meet various minimum gas quality standards in order to deliver any volume of gas into Union's system.

   Union does not rely on Ontario producer-delivered gas supply at any point on its distribution system.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

a) Please describe which risks of the proposed Community Expansion Projects are borne by shareholders as opposed to ratepayers.

Response:

a) Please see the response at Exhibit B.CPA.11.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

a) Please explain how Union proposes to treat the additional revenue generated by the Community Expansion Projects during the term of the current IRM plan.

Response:

a) Union proposes to include any variance in revenue associated with the forecast of customer attachments and volumes in the Community Expansion Project Deferral Account consistent with the Capital Pass-through Mechanism treatment of other major capital projects within Union's IRM framework.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

a) What benefits does Union believe accrue to existing customers as a result of the Community Expansion Projects?

Response:

a) Please see the response at Exhibit B.CCC.5.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

a) What other options for expanding natural gas distribution infrastructure was considered by Union? Please explain why they were not proposed.

Response:

a) Please see the response at Exhibit B.FRPO.1 and Exhibit B.Northeast.1.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Tab A

Please provide copies of all materials that were provided to Union's senior management team, and if applicable, its parent company's Board of Directors, for the approval to undertake both the individual projects sought in this application, and the entire 30 expansion projects.

Response:

Please see Attachment 1.

Community Expansion Filing

Potential Project & Portfolio PI Reductions

Community Expansion Steering Committee
June 2, 2015

Challenge

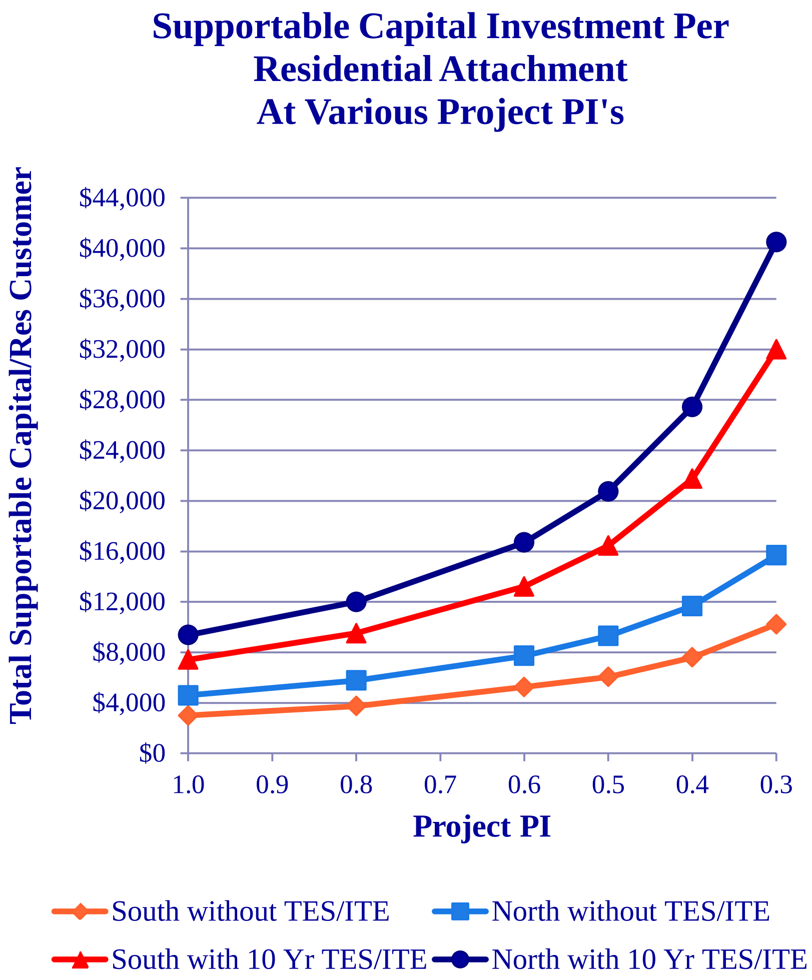
Is our ask for regulatory flexibility aggressive enough?

- Risk of Provincial funding being diverted or not materializing
- What are implications of asking existing ratepayers to fund a higher share of these projects?

Recommendations

1. **Minimum Project PI:**
   - Could modify proposal to reflect 0.5 rather than 0.6, but would faced increased risk of opposition and timelines.
   - Preference to leave at 0.6
   - Do not recommend reducing beyond 0.5
2. **Minimum Portfolio thresholds:**
   - Proposal should be adjusted
     - Drop minimum PI of 0.9, move to managing separate portfolios for Community Expansion Projects (exclude from traditional Rolling Project and Distribution Investment Portfolios)
     - Manage Community Expansion Projects such that maximum rate impact for residential customers is <$10/year rate increase

Impacts of Reduced Minimum Project PI's



Analysis Approach

- **Determined level of capital investment that an average residential customer load would support**
  - For both base delivery revenue as well as including the new surcharges for 10 years
- **Applied results against capital cost per customer for each project from viability sorted project list**
  - Included TES/ITE
  - Assumed various levels of provincial funding available

TES: Volumetric Expansion Surcharge for 10 years

ITE: Municipal contribution for 10 years

uniongas
A Spectra Energy Company

Notes on Analysis

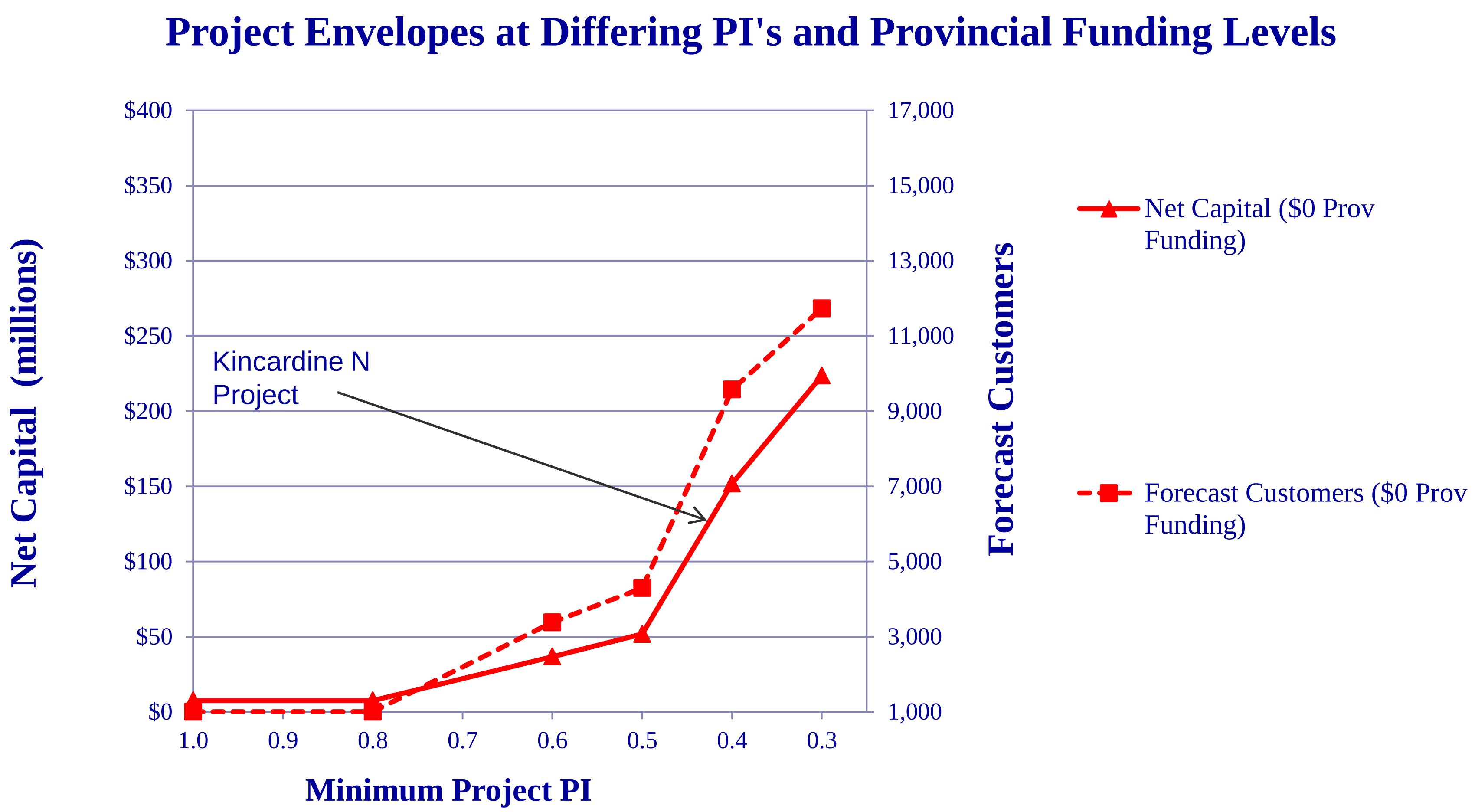
Conservative Factors in Approach (could result in increased actual projects & capital)

- 45% Conversion assumption not changed; could understate results based on recent surveys

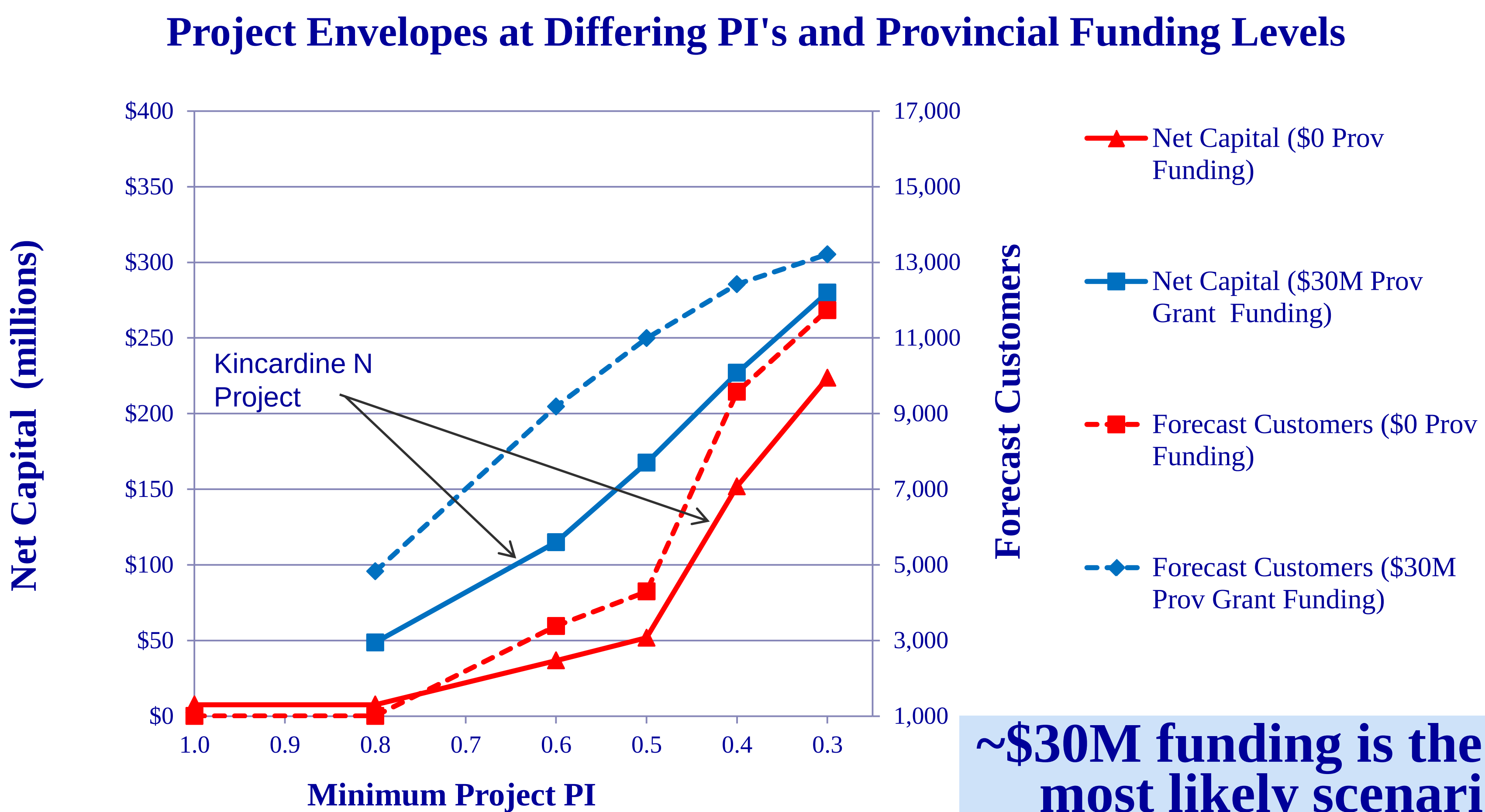
Aggressive Factors in Approach (could result in reduced actual projects & capital)

- Analysis doesn’t factor in customer conversion forecast timeline; will overstate results

Results of Analysis: Assuming No Provincial Funding



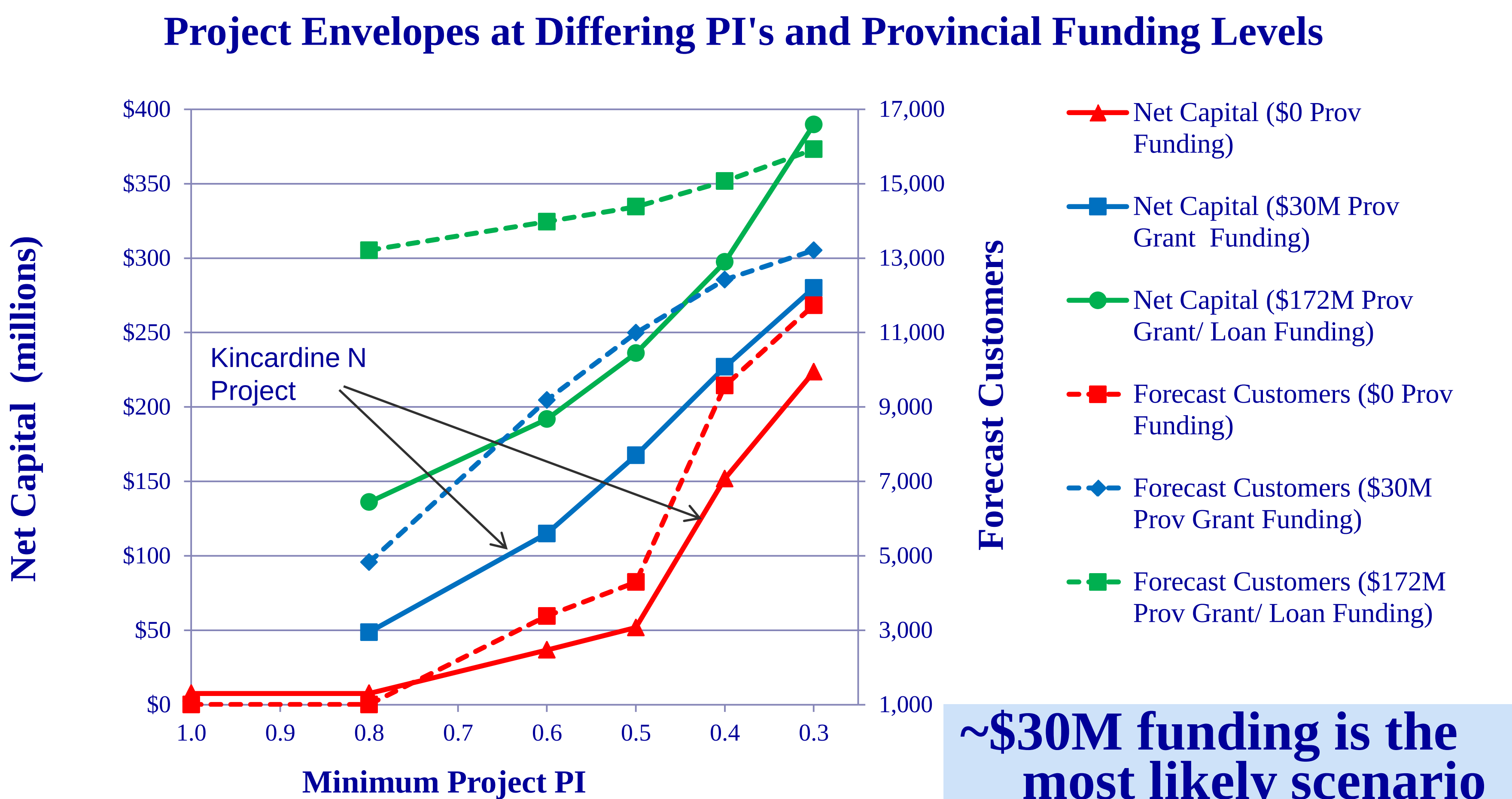
Results of Analysis: Including $30M in Provincial Funding



~$30M funding is the most likely scenario

uniongas
A Spectra Energy Company

Results of Analysis: Including $172M in Provincial Funding



~$30M funding is the most likely scenario

Estimated Term Rate Increases for Existing Ratepayers

There will also be short/medium term rate impacts as project PI's are not reached for a number of years

Assumption: increase chart values by 50%

$30M funding is the most likely scenario:

Annual Cost Impacts*:

0.6 PI= <$10/ year

0.5 PI= $15/year

0.4 PI=$22/year

0.3 PI= $31/year

* Chart values plus 50%

Annual Long Term Average Cost Impact at Differing PI's and Provincial Funding Levels

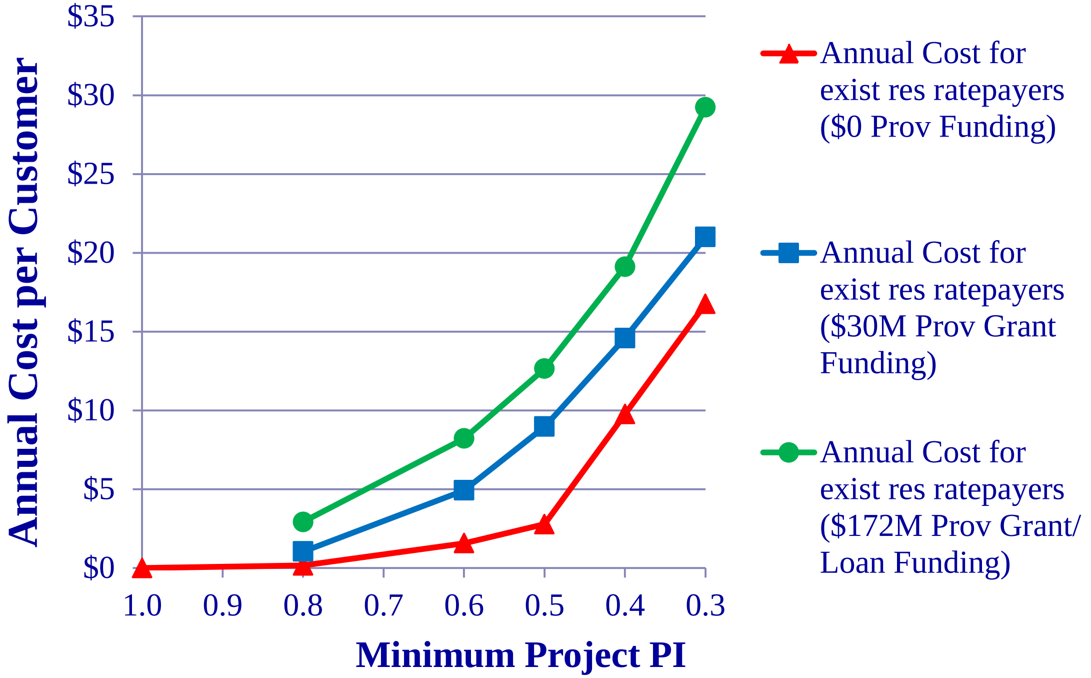


Chart based on simplified calculation:

Portion of net capital (rate base) not funded by project revenue

Times 15% pre tax rate of return

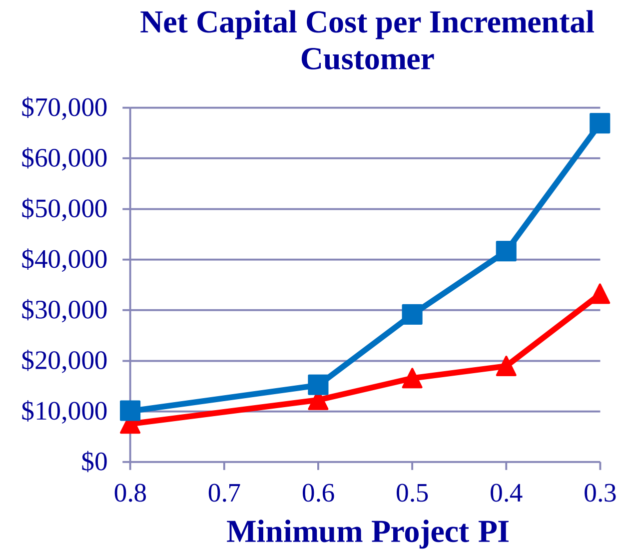
Divided by 1.4 million customers

uniongas
A Spectra Energy Company

Summary Results

Min Project PI	No Provincial Funding				$30M Provincial Funding			
	Projects	Customers	Net Capital	Net Cap/ Incr Customer	Projects	Customers	Net Capital	Net Cap/ Incr Customer
0.6	14	3,400	$37 M	$10,900	27	9,200	$115 M	$12,500
0.5	21	4,300	$52 M	$16,600	42	11,000	$167 M	$29,100
0.4	31	9,600	$152 M	$18,900	50	12,400	$227 M	$41,600
0.3	43	11,700	$224 M	$33,200	55	13,200	$280 M	$66,900

Escalating cost per incremental customer may draw attention in regulatory proceeding at PI's below 0.6



uniongas
A Spectra Energy Company

Key Points

- **Treatment of TES/ITE as tax exempt revenue puts 9 additional projects ($23M capital, 1,800 customers) in play with our current proposal of minimum PI 0.6. No Provincial funding required**

- **Notionally prefer to keep average rate impact < $20 per existing customer, spread over 2 years**
  - Implication is 0.5 PI is lowest we should propose
  - Consistent with previous communications with Ministries
  - Less than conservation costs proposed by Board ($24) but in case of DSM ratepayers benefit
  - Ratepayers do not benefit in a significant way from this program

- **Largest project, Kincardine North ($81-92M capital, 4,400 customers):**
  - PI =0.45 if no provincial funding
  - On the bubble with current 0.6 PI proposal; requires $24M in Provincial funding

Pros/Cons:
Reducing Proposed Minimum to 0.5 PI

Pros	Cons
• Potential for additional projects • Rate impact is reasonable	• Moderate risk of proposal being rejected- possible psychological barrier: Existing ratepayers having to pay for **half** of expansion through rate increases • Potential misalignment with Enbridge proposals • Delay in filing in order to confirm impacts (need to remodel all projects, gain muni acceptance to changes in letters of support) • Potentially behind Enbridge filing • Kincardine N project is on the bubble

Pros/Cons:
Reducing Proposed Minimum to 0.4 PI

Pros	Cons
• Maximizes additional projects • Kincardine N project is feasible even if no government funding (assuming Kincardine S is dropped) • Rate impact is still reasonable	•Heightened risk of proposal being rejected- possible psychological barrier: Existing ratepayers having to pay for **more than half** of expansion through rate increases • Likely misalignment with Enbridge proposals • Delay in filing in order to confirm impacts (need to remodel all projects, gain muni acceptance to changes in letters of support) • Potentially behind Enbridge filing

uniongas
A Spectra Energy Company

Impacts on Portfolio PI

- **Portfolio threshold reductions proposed at 0.9 will support incremental capital at 0.6 Project PI's of ~20M/year in both North and South.**
  - Risk that we are portfolio constrained even with no Provincial funding
  - Coincidental system reinforcement needs magnify risk
- **Assuming $30M in Provincial funding over 2 years:**
  - Portfolio thresholds would need to drop to 0.65 to accommodate project PI's at 0.4 ($55M net capital per year in north and south)
- **Nature of proposal should be adjusted to eliminate this constraint**

uniongas

A Spectra Energy Company

Community Expansion: New Tools for a New Market

ULG Meeting
Feb 7, 2014

Ask

- Endorsement of team approach and charter
  - Detailed document provided at recent ULG meeting
- Endorsement/awareness of program positioning (Provincial funding and directives)

Project Purpose and Scope

***Project Purpose**: Provide a set of additional enabling tools and approaches to support the financial feasibility of expanding the natural gas distribution system to non-serviced gas communities.*

In Scope

- Non serviced gas communities
- Rural agricultural (non community) expansion
- Quantification of Market Potential
- Traditional and Non Traditional Servicing Options
- Financing and Aid Collection Options
- Stakeholder advocacy
- Regulator Approvals

Out of Scope

- Execution of specific projects
- Implementation planning and resourcing post regulatory decision (Phase 2)
- "Off the grid" electric communities (remote CNG/LNG conversion opportunities)
- Individual attachments on existing main
- High Density Plastic (in town distribution)

Project Resources

Project Sponsor: Dave Simpson
Steering Team: ULG
Advisory Team: Wes Armstrong, Jackie Caille, Darrin Canniff, Pat Elliott, Matt Gibson, Shawn Khoshaien, Mark Kitchen
Project Lead – Jeff Okrucky **Project Manager** – Jeff Hodgins

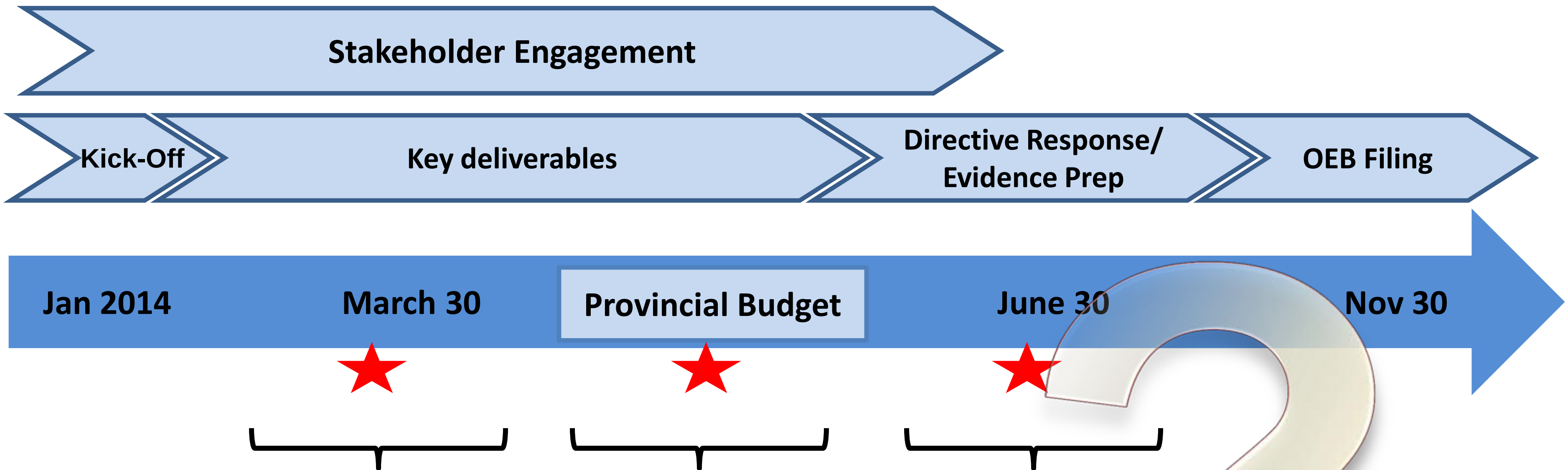
Regulatory: Chris Ripley • Coordination /case rate mg • Rate case design link • Support from Chris Gagner	**Operations:** Darryl Stokes, James Whittaker • Opportunity quantification • Costing • Supply design alternatives • Aid collection	**Gov't Affairs:** Paul Ungerman • Gov't Advocacy	**Financial Forecasting:** Dave Hockin • Modelling • Support from Matt Rountree
Engineering: Bryden Berkvens • Supply costing design Alternatives	**CNG/LNG:** Murray Smith • CNG alternative costing	**Market Research:** Barbara Gardiner • Opportunity quantification, Consumer research • Support from Carrie Ellis	**Public Relations:** Alex Moskalyk • Stakeholder Advocacy

Extended Team: **Finance** – aid collection process, **Customer Care** (Paula Ceccacci) – aid collection process, **Municipal Affairs** – advocacy

Key Deliverables

1. Define policy positioning and financing options
2. Define traditional pipeline supply options and costs
3. Define CNG supply options and costs
4. Verify community expansion potential, costing and economics
5. Verify rural expansion potential and costs
6. Advocacy plan and supporting materials

Project Timelines/ULG 'Touch Points'



- Policy positioning defined
- Opportunities quantified
- Community level economics
- Cost reduction opportunities defined
- Advocacy plan defined

- Provincial funding commitment
- OEB directive delivered
- Stakeholder consultations on program design initiated

- Program design finalized
- Candidate projects determined for 2015
- Implementation planning (phase 2) underway

Current Status

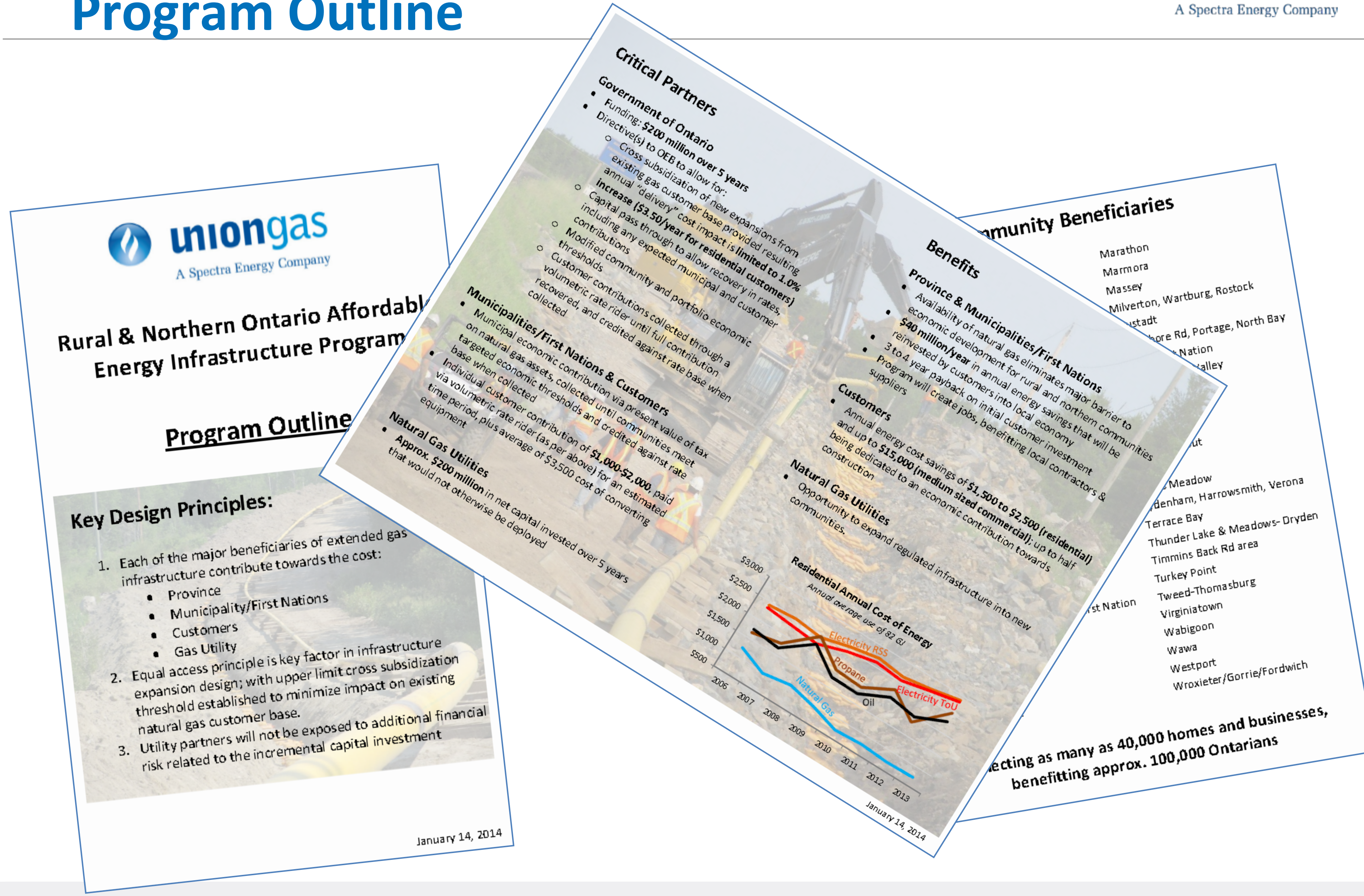
Stakeholder Engagement

- MOE
    - Shared program outline and options (see appendix)
    - Appear supportive; engaging other ministries for support/funding
    - Continued engagement on program design discussion
- Enbridge- Aligned on principles and directive content
- OFA- preliminary dialogue planned Feb 11

Project Team

- Kicked off Jan 30
- Heavy engagement level required for next 4-8 weeks

Program Outline



Program Options

Total Investment	$700M gross capital over 5 years Up to 47,000 customers in over 80 communities connected	$400M gross capital over 5 years Up to 40,000 customers in over 40 communities connected	$400M gross capital over 5 years Up to 40,000 customers in over 40 communities connected

Stakeholder	Option A	Option B	Option C
Gas Utility	**$300M capital invested over 5 years**	**$200M capital invested over 5 years**	**$200M capital invested over 5 years**
Government of Ontario	**Direct Funding: $400M grant over 5 years**, and **Directives to OEB** to allow for: o Cross Subsidization of new expansions from existing ratepayers provided resulting annual delivery cost impact is limited to **0.5% increase**, and o Capital pass through to allow recovery in rates, including any expected municipal and customer contributions, prior to end of IR period, and o Modified community and portfolio economic thresholds, and o Expansion area customer construction contributions collected through a volumetric rate rider, applied until communities meet economic thresholds, and credited against rate base annually when collected	**Direct Funding: $200M grant over 5 years**, and **Directives to OEB** to allow for: o Cross Subsidization of new expansions from existing ratepayers provided resulting annual delivery cost impact is limited to **1.0% increase**, ($3.50/year for residential customers) and o Capital pass through to allow recovery in rates, including any expected municipal and customer contributions, prior to end of IR period, and o Modified community and portfolio economic thresholds, and o Expansion area customer construction contributions collected through a volumetric rate rider, applied until communities meet economic thresholds, and credited against rate base annually when collected	**Direct funding: $100M grant over 5 years**, and **Directives to OEB** to allow for: o Cross Subsidization of new expansions from existing ratepayers provided resulting annual delivery cost impact is limited to a **1.5% increase,** and o Capital pass through to allow recovery in rates, including any expected municipal and customer contributions, prior to end of IR period, and o Modified community and portfolio economic thresholds, and o Expansion area customer construction contributions collected through a volumetric rate rider, applied until communities meet economic thresholds, and credited against rate base annually when collected

Program Options

Other Contributions	
Expansion Area Customer	Construction contribution totalling $1,000-$2,000 through volumetric rate rider, plus Cost of converting equipment averaging $3,500
Municipality	Minimum economic contribution (aid) valued at present value of pipeline tax contributions, collected up front or annually until communities meet economic thresholds, and credited against rate base when collected Option to provide incremental funding to improve project economics

Program Options

Potential Community Screening Mechanisms

- Minimum community size(total number of homes and businesses), first come first served, provided project passes specified economic test threshold after applying a provincial contribution with a ceiling per home/business, or
- Minimum community size, and following a formal application period each year:
  - Lowest provincial contribution (as % of gross capital) required to meet economic test threshold first, provided project meets specified economic test threshold after applying provincial contribution, or
  - Rank order, largest to smallest community, after applying a provincial contribution with a ceiling per home/business, and provided project meets specified economic test threshold after applying provincial contribution
  - Economic test criteria could be set with slightly lowered requirements for larger communities in order to build a hybrid of these two options

In all cases minimum community size thresholds could be reduced each year. Communities could improve their ability to compete for funding by coming to the table with additional contributions.

uniongas
A Spectra Energy Company

Community Expansion Project: Update

April 23, 2014

Agenda / Ask

- Share Project Status
- Endorsement of key outcomes discussed with Advisory Team
  - Refined Customer and Municipal Funding
  - CNG Regulatory Modelling Approach
- Endorsement of next steps

Project Advisory Team: Kitchen, Caille, Armstrong, Canniff, Elliott, Gibson, Khoshaien

Key Charter Deliverables

1. Define pipeline supply options and costs	**Complete**
2. Define CNG supply options and costs	**80%**
3. Verify community expansion potential, costing and economics	**Complete**
4. Verify rural expansion potential and costs	**80%**
5. Advocacy plan and supporting materials	**On -Going**
6. Positioning and Financing Options	**Complete**

Program Outline

55^3

Potential Levers

- **Provincial Gov't**
- **EBO 188 Requirements**
- **Expansion Customer / Municipal Funding**
- **Federal Gov't**

- **Up to:**
  - 55 communities serviced
  - 55,000 homes and business given access to natural gas
  - $55 million per year in energy savings for community members

Refined Funding and Regulatory Treatment

Customer Contributions:

- Use a '*volumetric rate rider*' *(i.e. 0.15/m3)* that would be the same for all expansion areas
- Term of contribution would be tied to expansion forecast; <u>any shortfall would fall to municipality to make up</u>

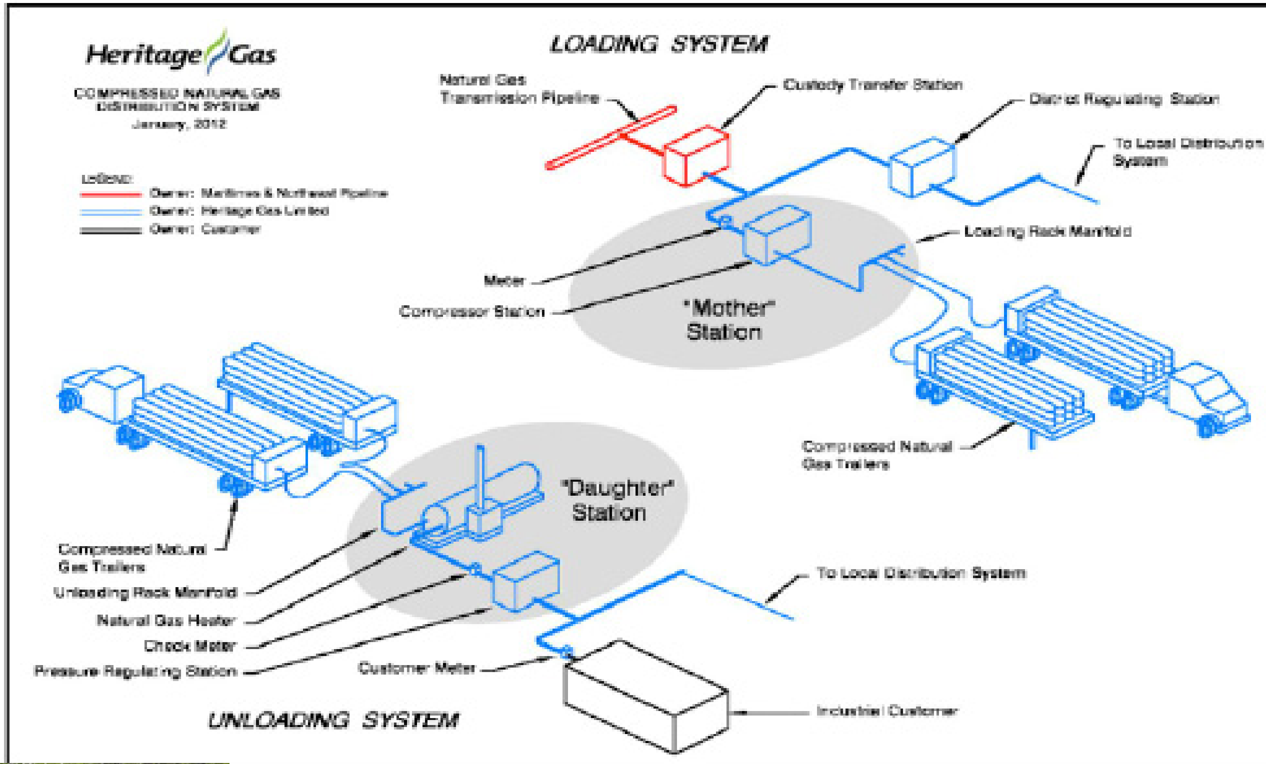
Municipal Contributions:

- Potential source of municipal contributions in the form of an amount equal to the property taxes UGL would pay the municipality annual *(~1% of gross capital)*
- Municipal contributions <u>would continue</u> until shortfall in project economics is fully covered

Capital Pass Through Treatment:

- **New assets** added to rate base **net of government aid** but will include customer / municipal contributions.
- As customer and municipal contributions collected, **rate base would be reduced on annual basis**

CNG Supply Option



Operational Risks/Impacts:

- Trucking
- Weather / Road Closures
- Supply Interruptions (source, mother stn.)
- Internal structure, skills

CNG Supply: Regulatory Model

Options:

1. Fully Regulated

- Mother stn., truck trailers, daughter stn. and distribution piping owned by UGL and included in rate base
- Trucking of CNG contracted out to transport firm

2. **Partially Regulated**

- Mother Stn., truck trailers and trucks unregulated; daughter station and distribution piping regulated
- UGL would procure gas supply upstream of daughter station(including transport) and roll into WACOG as a cost of gas supply

Interim Position (Modelling Purposes): Fully Regulated

- Consistent with UGL current expansion practices
- Facility costs in delivery rates and customers charged OEB approved rates
- Trucking not part of UGL core business / competencies

Next Steps / Options

- ✓ CNG costing and modelling
- ✓ Continued advocacy
- ✓ Project team wind up - expected in May

Appendix

unionGas
A Spectra Energy Company

Community Expansion Potential and Economics

	Union Gas	Enbridge	Total
Total Communities	159	32	191
Total Population	124,100	34,300	158,400
Max Customer Potential	55,800	13,300	69,100
>100 Potential	119	32	151
> 500 Potential	24	8	32

*****Avg distance from supply source ~ 31km***

Union Gas Economics	Pipeline Supply	CNG Supply
PI Range	.02-.65	in progress
Minimum Aid/Customer (PI=1.0)	$3000	in progress
Minimum Aid/Customer (PI=0.8)	$1740	in progress
Minimum Aid / Customer (PI=0.6)	$0	in progress

*****45% attachment forecast***

Notional Funding Model (UGL and Enbridge)

Gross Capital per customer	$14,000
Funding: Gas Distributor Investment	
Within current regulatory framework (PI=.8)	$5,000
Incremental via relaxed regulatory PI requirements (PI=.6)	$1,500
Incremental via expansion area customer surcharge	$2,000
Incremental via Municipal property tax rebate	$500
Remaining Gap: Province of Ontario contribution	$5,000

Economic Modelling Results- Pipeline Supply (UGL only)

uniongas
A Spectra Energy Company

PI	Communities Served	Total with Access	Forecasted Attachments	Required Gov't Funding
1.0	45	22,540	10,218	$133 M
0.8	45	22,540	10,218	$ 127 M
0.6	45	22,540	10,218	$117 M

*****57,700 population*** *****45% forecast***

Assumptions:
- **Gov't Funding** = maximum $5000 / household and business with access to natural gas
- **Municipal Funding** = $500 / household and business with access to natural gas
- **Customer Contributions** = $2000 / attachment

Notes:
- **$200M Gov't Funding** = 76 communities and 29,000 with access (~$7000 per household)

Community Expansion

Initiative Status Report

November 7, 2014
Matt Gibson/Jeff Okrucky

Desired Outcome

Endorse Structure and Timeline

Continued alignment on Provincial and OEB asks and associated rationale

Awareness of top potential projects

Advocacy Status

- Mandate Letters: Economic Development as Lead. Energy, Ag/Rural Affairs, Municipal Affairs supporting
- Ongoing dialogue: Energy, EcDev and Ag. Meeting with Minister of EcDev delayed
- Lobby Day meetings: Municipal Affairs staff. Meeting with Minister delayed
- Supporting partners aligned – OFA and EGD. OFA meeting with Minister of Ag and Municipal Affairs on UGL Lobby Day

Regulatory Flexibility: Our Asks

PRIMARY TARGET: Ministry of Energy and OEB

Review of previous discussion:

1. **Capital Pass Through to Rates (Y Factor Eligibility)**
   - ❑ Protects shareholder from impacts of low initial period project PI's during IR framework
   - ❑ Few projects with net capital >$50M (Y factor), however, portfolio of projects highly likely to exceed this
2. **Project Economic Feasibility: Project Minimum PI of 0.6, Investment Portfolio Minimum PI of 0.9**
   - ❑ Combination allows for incremental capital spending of up to $60M/year within envelope; grant availability likely to limit this to > $30M/year
   - ❑ Portfolio PI reduction allows for up to $18M/year in capital investment cross subsidized from existing ratepayers (rate impact $2/year/customer)

uniongas
A Spectra Energy Company

Regulatory Flexibility (Our Asks cont'd)

3. **Volumetric Rate Rider ("Expansion Surcharge") approval: Rate and Accounting Treatment**
   - Same rate for all projects; time period varies by project based on economics
   - Treated as a deferred form of Aid to Construction; mechanical treatment is initial inclusion in rate base, with removal from rate base of amount paid each year
   - *Proposed at 23 cents/m3 for up to 8 years
   - *Costs $450-500/residential customer per year, or max 1/3 of annual energy savings.
     - Remaining energy savings (>$1,000/year) pay for average equipment conversion in 3-4 years
   - Becomes a major contributor to economic shortfalls.
   - Currently validating conversion value proposition for larger C/I (M2/R20/contract) customers
4. **Muni Contribution Accounting Treatment**
   - Propose same accounting treatment as Expansion Surcharge
   - Equivalent to incremental municipal taxes each year for minimum period equal to rate rider, extended if attachments delayed
   - Puts municipal skin in the game, and mitigates urge to inflate attachment forecasts

* new information: not previously discussed in depth

uniongas
A Spectra Energy Company

Regulatory Flexibility: Gap and Resolution

Gap: How do we initiate a short term holistic review of proposals by OEB

- Avoid drawn out EBO188 like proceeding (>2 years)
- Ideally look for conclusions early 2015

Options

- Recommended: Ask for MoE Directive to OEB for time-bound review
  - Leads to clarity on forum and process in the shortest timeframe
  - Opportunity to have input in specific content
- Ask OEB for clarity on review forum and timelines.
  - Likely not short term in nature
- File for a specific project that does not require a grant or loan
  - Milverton a strong candidate
  - Non-holistic review is likely to rule out a capital pass through.

Preparation: MoE Education on concepts and impacts on portfolio is underway

Provincial Grants and Loans: Our Asks

PRIMARY TARGET: Ministry of Economic Development

Immediately commence dialogue with key stakeholders to define:

- Criteria for eligibility for both grants and interest free loans
- Criteria to be applied in prioritizing potential projects
- Specific factors to be considered in assessing economic development impacts
- Development of the process to be utilized to access grants and loans

uniongas
A Spectra Energy Company

Grants/Loans: Gap and Resolution

Gap

- Accountability not assigned within Min of EcDev

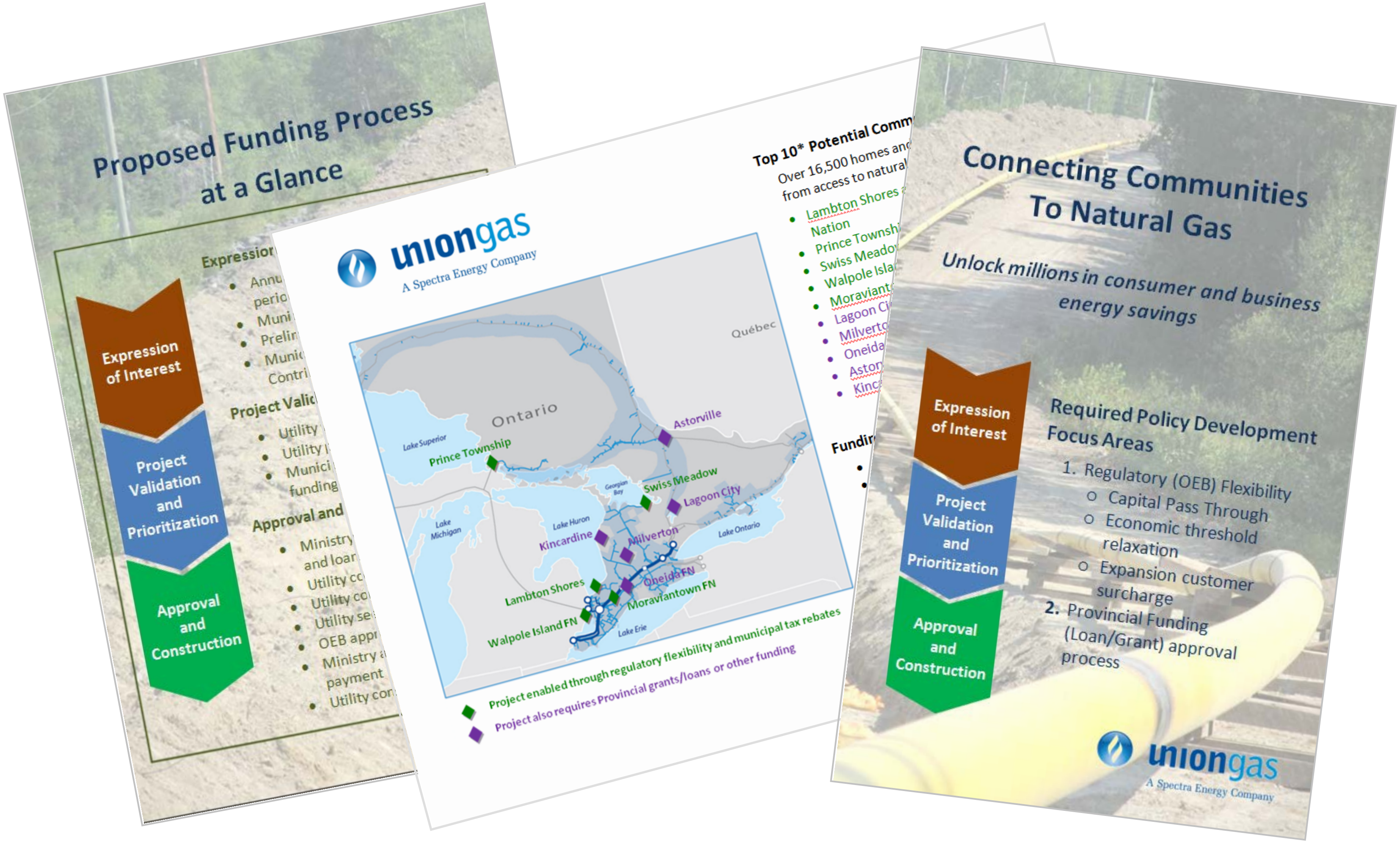
Options

- Advocate for immediate action in Nov 18 EcDev Deputy Minister/ CoS meeting (GR) and Dec 3 Duguid meeting (Baker/GR)
- Continue to engage support of other stakeholders in advocating immediate action (muni association resolutions)

Preparation

- Continued ongoing engagement with municipal groups
- Program Proposal Summary drafted
- Joint Utility Proposed Process under development in anticipation of EcDev engagement

Program Proposal Summary



The Path Forward

Union strategic push and asks to focus on:

1. **Move quickly and deliberately**
2. **Assign direct accountabilities and coordination across government**
3. **Immediate <u>moves?</u> on regulatory flexibility**
4. **Achieve "early wins" while simultaneously focusing on larger program rollout**

Outreach:

- **50% of effort focused on EcDev, 40% with Energy and 10% between remaining two and OPO**

Timelines:

- **Ministerial Directive?: Jan/Feb 2015**
- **Program Consultation Period: Jan to April 2015**
- **Program Announcement and Rollout: Spring Budget (April 2015)**

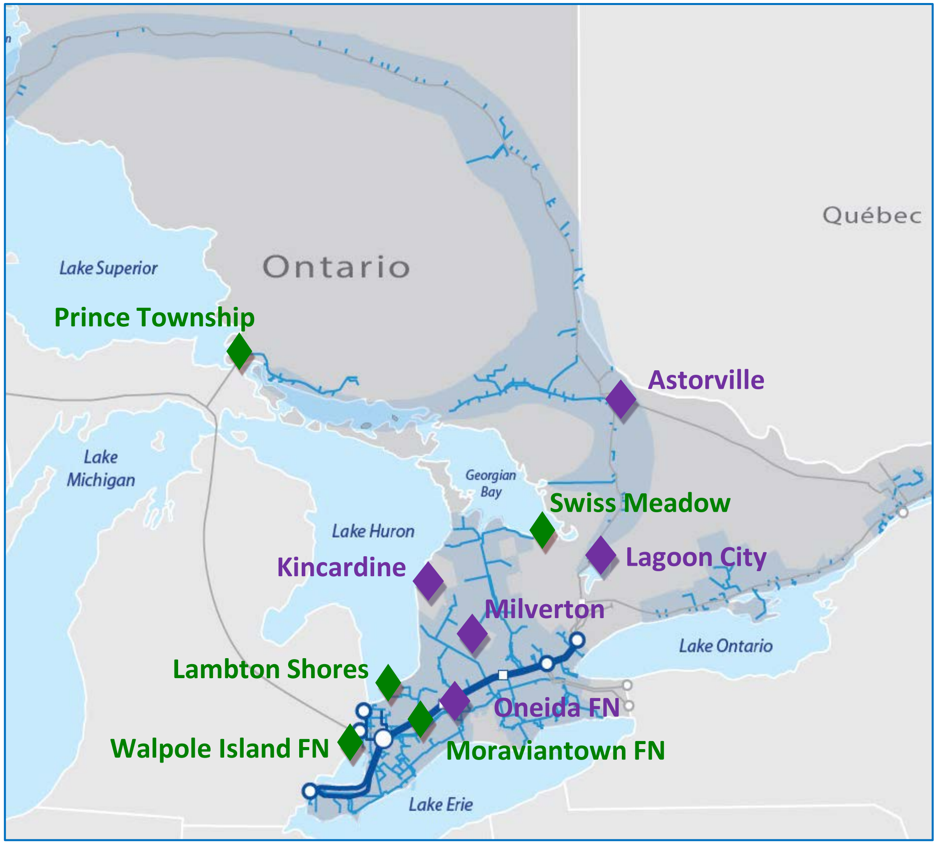
Appendix

Top 10 Community Rankings

Suggested MoE Directive content

Suggested Grant/Loan Criteria

Top 10* Potential Projects



- Lambton Shores and Kettle Point First Nation
- Prince Township (S.S. Marie)
- Swiss Meadow
- Walpole Island First Nation
- Moraviantown First Nation
- Lagoon City (Orillia)
- Milverton
- Oneida First Nation
- Astorville
- Kincardine/Tiverton/ Paisley/Chesley

◆ **Project enabled through regulatory flexibility and municipal tax rebates**

◆ **Project also requires Provincial grants/loans or other funding**

*Based on community size and economic viability

uniongas
A Spectra Energy Company

Funding the Top 10

$110M-$130M gross capital cost

$105M-$120M in required economic support. Possible funding mechanisms:

- $45M: Expansion Surcharge
- $15M: Economic Threshold Reduction
- $10M: Municipal Tax Rebates
- $35M-$50M: Provincial Grants/Loans or Other Sources

Suggested MoE Directive Content

Time bound- decision to be public by end of Q1 2015

Asks that the OEB solicit proposals by Utilities and other stakeholders, ensuring the following areas are considered:

- A means of ensuring gas utilities are not exposed to negative financial impacts or incremental risks by increasing distribution expansion related investments through the terms of their incentive regulation frameworks
- Suggest consideration be given to providing for incremental capital to be included in rate base in the year in which it occurs
- Encourage consideration of new mechanisms to allow for customers and municipalities to contribute to project feasibility from the economic benefits they receive each year
- Recognizing potential positive impact on rural and northern economies,
  - Suggest limited forms of long term cross subsidization from existing customers is appropriate
  - Suggest increased flexibility through a reduction in minimum economic thresholds for both individual projects and utility investment portfolios

Suggested Grant/Loan Criteria

Density and Defined Project Areas

- ❑ 100+ homes and or businesses using heat/process energy load, or First Nation service area
- ❑ Maximum average of 100 metres between properties (applies to non First Nation projects)

Municipality must agree to convert all owned buildings

Minimum Project Economic Thresholds

- ❑ Minimum PI of 0.6 from gas utility modelling using standard economic modelling assumptions
  - Includes expansion surcharge, municipal tax rebate value, grant ceiling of $5K/property,

Municipality or other parties must agree to any supplemental aid required to achieve feasibility

Community Expansion Filing

ULG Checkpoint

Jeff Okrucky, April 24, 2015

Background

- **Provincial funding**
  - Commitment of $200M in interest free loans and $30M in economic development grants announced and confirmed in Chiarelli letter to OEB February 16
  - Expectation that it will be in 2016/17 budget
- **Ministry (MEDEI) has initiated internal dialogue on funding criteria**
  - Union shared full community list in late March
- **OEB invited interested parties to submit applications including requests for regulatory flexibility or exemptions February 17**

Status

- **Union preparing filing for 6 specific communities, along with request for regulatory flexibility for broader public financed program**
  - Communities included could proceed without direct provincially sourced funding
  - Target end of May for filing
  - Team formed and charter approved
  - Detailed project costing and market surveys underway
  - Evidence being prepared

Filing Scope

- **Section 36 approval for volumetric Temporary Expansion Surcharge (TES)**
- **For current and future community expansion projects:**
  - Capital pass through for all community expansion projects
  - Minimum PI's (specific projects reduced to 0.6, portfolios reduced to 0.9)
  - Municipal tax rebate
  - Accounting/rate base treatment for TES and muni tax rebate funds
- **Section 90 approval for Milverton and Lambton Shores/Kettle Point FN projects**
- **Filing will reference scope of all 140 communities identified and potential for projects moving forward when Provincial funding becomes available.**
- **Scope is limited to filing and proceeding; excludes actual execution of specific projects subsequent to decision (reverts to Dist Ops)**

Specific Communities

District	Community	Gross Capital *	Customer Potential	Customer Forecast*
London	Milverton	$4.8 M	1082	490
London	Lambton Shores/Kettle Pt F.N.**	$4.6 M	1620	729
North East	Prince Township	$1.6 M	466	210
Windsor	Walpole Island F.N.	$0.6 M	70	70
Windsor	Moraviantown F.N.	$0.3 M	45	45
Hamilton	Hornby	$0.1 M	45	20
	TOTAL	**$12.3 M**	**3,328**	**1,564**

- All will be subject to validation as detailed costing is pulled together.
- Swiss Meadow (Collingwood) has been dropped from the "top 5" list as inability to gain agreement for a supply line easement will push costs up to point where provincial funding would be required to make the project economically feasible.

* Cost and forecast as of Spring 2014; will be updated with detail as filing is finalized
**Upstream capacity available to accommodate for Lambton Shores is currently being reviewed.

uniongas
A Spectra Energy Company

Engaged Resources

Project Team		Steering Committee
Operations	Jennifer Burnham	Dave Simpson (Sponsor)
		Rick Birmingham
Regulatory Affairs	Greg Thompson	Mark Kitchen
	Chris Ripley	Mike Shannon
	Chris Gagner	Wes Armstrong
	Bill Wachsmuth	Wendi Zelond
Finance	Richard Wathy	Sherry Steingart
	Dave Hockin	Matt Gibson
	Mat Rountree	

Additional engaged resources: C&G groups in applicable Districts, Public Affairs, Finance, Engineering Services, Distribution Planning, Muni and Aboriginal Relations, Property Tax

Risks

- **Filing**
  - Timing
    - Project specific: costing/community engagement/economics
    - Board Proceeding
      - 5 month minimum for a traditional oral proceeding
      - OEB preference for joint proceeding with Enbridge
      - At best late summer hearing expected; high risk that no construction can begin in 2015
  - Resistance to any forms of cross subsidization from existing customers
- **Longer Term Concerns**
  - Migration to monthly flat rate electric distribution charges
  - Reduced oil, propane prices
  - Fracking, Cap and Trade

Appendix

Reference detailed charter sent separately

Project Name:	**2015/16 Community Expansion**
Project Sponsor:	Dave Simpson
Project Lead:	Jeff Okrucky
Project Manager:	Richard Wathy

1.0 Project Purpose

Drivers

- Increasing interest from potential customers and municipal officials in non-gassed communities in obtaining natural gas service as a result of escalation costs for competing energy forms
- Traditional distribution expansion opportunity estimated at:
  - $55M gross capital/$26M net capital over 3 years to provide access to 11,000 potential customers (assuming use of Provincial Grants only by municipalities), generating an eventual annual revenue stream of $3.7M/year
- Maximum of $311M gross capital over 3 years to provide access to 30,000 potential customers (assuming full use of all Provincial grants and loans by municipalities)

Strategic Alignment

Supports Union Gas Purpose:

- Our energy enhances the quality of life and the prosperity of our province and our customers

Supports Union Gas goals:

- Aggressively protect and grow our business
- Achieve exceptional regulatory outcomes
- Builds on our high-performance culture
- Strongly advocate for natural gas, our industry and our company

Project Background

- Union has advocated heavily for provincial funding to support connecting additional rural and northern communities to the gas system.
- Provincial government committed to investigate approaches to expand the gas system to additional rural and northern communities in 2013 Long Term Energy Plan,
- In early 2014 a Union project team concluded work to quantify the size of opportunity. 140 communities representing over 45,000 potential customers were modelled.
- Provincial government committed to funding $200M in natural gas access loans and $30M in economic development grants in June 2014 election platform, and recently confirmed (Feb 2015) commitment in correspondence from Energy Minister to OEB. Funding is expected to become available in spring 2016 Provincial budget
- Union has advocated to Province that flexibility in regulatory approach would allow the committed funding to be leveraged to extend reach
- Ontario Energy Board issued an invitation to interested parties to submit expansion proposals along with proposed forms of regulatory flexibility in February 2015.
- Union intends to respond to OEB invitation with a filing seeking approval for regulatory flexibility for up to 6 specific projects that would not require Provincial funding support, as well as approval to apply same flexibility to any projects that become viable when Provincial funding support becomes available in 2016.

- Filing target for end of May 2015 in order to have potential to construct at least one project before year end.
- Timing for filing is intended to enable Union to build a sense of momentum for the Provincial funding program with a view to:
    - o Solidify the funding commitment in the 2016 Provincial budget,
    - o Positively influence potential to have a longer term program funded
    - o Enhance Union's reputation with Government for ability to follow through on commitments.
- Specific Projects are expected to include the following:

District	Project	Gross Capital *	Customer Potential	Customer Forecast *
London	Milverton	$4.8 M	1082	490
London	Lambton Shores/Kettle Pt F.N.**	$4.6 M	1620	729
North East	Prince Township	$1.6 M	466	210
Windsor	Walpole Island F.N.	$0.6 M	70	70
Windsor	Moraviantown F.N.	$0.3 M	45	45
Hamilton	Hornby	$0.1 M	45	20
		$12.3 M	**3,328**	**1,564**

* Cost and forecast as of Spring 2014; will be updated with detail as filing is finalized
**Upstream capacity available to accommodate for Lambton Shores is currently being reviewed.

- o All will be subject to validation as detailed costing is pulled together. One community, Swiss Meadow, has been dropped from the list as inability to gain agreement for a supply line easement will push costs up to point where provincial funding would be required to make the project economically feasible.

2.0 Project Scope

In Scope	Out of Scope
Regulatory filing for section 36/Section 90/91 approval to expand to communities that are economically feasible if flexibility proposals are approved, and approval to continue to use same approaches when Provincial funding becomes available. Regulatory flexibility proposals include: • Temporary community expansion surcharge rate and related accounting treatment • Municipal tax rebate contribution and related accounting treatment • Capital pass through, including surcharge and tax rebate value until such time as they are collected • EBO188 defined economic feasibility	Execution of projects approved by OEB Any projects that would require additional financial contributions beyond those included in regulatory flexibility approvals Non-traditional means of expanding to communities (e.g. CNG distribution model)

threshold reductions: PI thresholds reduced at project level (to 0.6), as well as portfolio and rolling project levels (both to 0.9) Potential specific communities are limited to those listed above.	

2.1 Critical Success Factors

- Pre-filed evidence filed on or before May 31, 2015
- Regulatory decision by end of September 2015 (very high risk if traditional timelines apply)
- At least one smaller project completed by year end.

2.2 Project Dependencies

- Capital is available for noted projects for 2015 and 2016
- Resource available for evidence development, which includes detailed costing and required EA's for each of the potential communities

2.3 Key Stakeholders

- Intervenors - rate impact and cost allocation concerns.
- Ministries of Energy and Economic Development and Trade - potential impacts on Provincial grant and loan program
- Municipalities, Municipal Associations (AMO, FoNOM), and First Nations, most specifically for the potential projects being proposed in this phase, but also those that might become economic with Provincial grants and loans.
- Ontario Federation of Agriculture, Ontario Chicken Farmers, etc - applicability of approved regulatory flexibility to rural system expansion
- Enbridge - intends to file a similar application
- A stakeholder plan to engage supporting parties in the hearing process will be defined as evidence is developed. Expect to target higher priority municipalities and agricultural associations.

2.4 Strategy Development

- Strategy developed in Q2 2014, defining key asks:
  - Capital pass-through
  - Temporary Expansion Surcharge rate rider
  - Muni tax rebates
  - Treatment of surcharge and tax rebate as deferred forms of Aid, with related values included in rate base until they are received
  - Reduced economic PI thresholds at project, portfolio and rolling PI levels.

3.0 Project Deliverables/High Level Schedule

3.1 Project Schedule – Deliverables, Checkpoints & Resource Requirements

Key Deliverable	End Date
Evidence outline drafted	April 1
Detailed project costing and EA's	April 30
Customer forecasts developed	April 30
Evidence ready for legal/regulatory review	May 18
Stakeholder plan (supporting groups) developed	May 15
Evidence filed	June 1
Hearing	August?
Decision	September?

Steering Committee Checkpoints	Target Date	Forum
Evidence outline and approach	Mid April	VC
Status	Early May	VC
Status and costing details	Mid May	VC
Review filing detail	Late May	VC
	Late August	VC
	Late September	VC
ULG Checkpoints	**Target Date**	**Forum**
Evidence approach and outline	Mid April	In person/VC
Filing summary	June	In person/VC

- Goal will be to discuss key strategies and issues on a monthly basis with the Advisory Team

4.0 Project Organization/Resources

- Core Team – Development and execution of the project, bi-weekly meetings and as required

Area	Name	Role
Marketing	Jeff Okrucky	Sponsor, policy evidence ownership
Operations	Jennifer Burnham	Facilities evidence ownership, operations and muni affairs liaison
	Greg Thompson	Facilities evidence support and liaison/coordination with applicable District C&G groups
Regulatory Affairs	Chris Ripley	Coordination of application and evidence, regulatory guidance for policy related evidence
	Chris Gagner	Evidence coordination, intro and EBO188 history evidence prep
	Bill Wachsmuth	Regulatory guidance for facilities approval related evidence and liaison with

		Engineering Environmental Planning
Finance	Richard Wathy	Project manager, policy evidence development, Finance accounting treatment
	Dave Hockin & Matt Rountree	Economic modelling and finance support

- Extended Project Team – Includes internal stakeholders directly involved in development or execution, with communication via core team members. Extended Project Team includes C&G managers in Windsor, London, Hamilton, NE, John Bonin/Lindsay Boyd and Doug Schmidt
- Steering Team – Strategy input and endorses strategies, monthly updates (or as required), provide leadership, guidance and direction to Project Lead and Project Manager, discussions to include Project Manager.

Area	**Name**
Sales & Marketing	Dave Simpson
Regulatory Affairs	Rick Birmingham Mark Kitchen
Operations	Mike Shannon Wes Armstrong
Finance	Sherri Steingart Wendi Zelond
Government Relations	Matt Gibson

5.0 Project Risks

- Filing preparation on a very tight timeline. High critical path risk points include customer forecasts, detailed costing, and development of environment assessments being prepared while snow is still on the ground (all required by end of April).
- Hearing type and timing for steps in procedural order; if traditional timelines it would be very unlikely to see a decision before mid fall
    - Typically one month notice before PO is developed, minimum 1 month for IRs, hearing, followed by 2 months for decision, estimate 5 months minimum for a traditional oral proceeding.
- Board has exptressed interest in hearing Enbridge proposals in same venue. Enbridge expects to file in early summer, which would likely delay hearing and decision if a joint proceeding is required.

6.0 Project Communications

- Regular governance meetings (Advisory Team, Core Team), and periodic ULG Update Meetings

Document Control				
Version #	Version Date	Modified by:	Approved by:	Method of Approval:
1	2015/04/01	J Okrucky		
2	2015/04/14	J Okrucky		

uniongas

A Spectra Energy Company

Community Expansion

OEB Filing Status Update

ULG Checkpoint: July 17, 2015

Agenda

- Intent:
  - Filing Update
  - Support for Communication Plan

- Agenda:
  - Status Update: Filing and Communication Plan
  - Communication Plan
  - Content Highlights
  - Changes in Approach
  - Potential Projects

Current Status

- Expect to file proposals next week
- Filing includes Policy Proposals for broader expansion program as well as a number of specific projects
  - Provides scope of a broader expansion program focussed on projects that may not require support from announced provincial grants and loans
    - » *Focus on merits of proposal that would enable as many as 30 projects to serve 34 communities*
    - » *Intent to avoid need for future advance approvals for projects that would typically not require facilities approvals from the Board*
    - » *Also identifies 72 other possible projects with amount of financial support required from a provincial funding program*
  - Specific project proposals for 5 projects to service 6 communities
    - » *Section 90 (OEB Act) facilities approvals for 3 projects*
    - » *2 additional projects that would not normally require facilities approvals*
- Communication Plan developed (refer to separate documents)

Key Elements of Proposal

<u>Community Expansion Projects</u>

1. Expansion Customer Contributions: Volumetric “Temporary Expansion Surcharge “(TES)
2. Municipal Contributions: “Incremental Tax Equivalent” (ITE)
3. E.B.O. 188 Economic Threshold Exemptions
   - Project minimum PI decrease from 0.8 to 0.4
   - Exemptions from inclusion in both Investment Portfolio and Rolling Project Portfolio; manage to a rate impact ceiling of $10/year for residential customers in any given year
4. Capital Pass Through to rates and related deferral accounts

<u>Small Main Extension Projects</u>

5. Volumetric “Temporary Connection Surcharge” (TCS)

<u>Specific Projects Proposed:</u>

- Section 90 Approvals: Milverton, Lambton Shores/Kettle Point First Nation, Prince Township
- Other projects: Walpole Island First Nation, Moraviantown First Nation (limited to commercial area for both)

Summary of Changes in Proposals

Current Guidelines	Previous Discussion	Filing Proposal
E.B.O. 188 Exemptions		
Project PI minimum of 0.8	Project PI minimum of 0.6	Project PI minimum of 0.4
Investment Portfolio PI minimum of 1.1 Rolling Project Portfolio PI minimum of 1.0	Portfolio PI minimum of 0.9 (for both)	Exemption from inclusion in portfolio; limit related capital by setting an expected annual cost increase ceiling of $10 for existing residential customers
Customer and Municipal Contributions		
Up-front Aid to Construction	TES as deferred form of Aid to Construction	TES as pass-through revenue
Up-front Aid to Construction	ITE as deferred form of Aid to Construction	ITE as pass-through revenue

Why the Changes in Approach?

- E.B.O. 188 Exemptions:
  - Advice from Minister (EDEI)
  - Analysis of the possible number of projects to find optimal minimum PI level
  - Target manageable rate impacts (<$10/year increase per residential customer) that still leave room for further projects when provincial financial support becomes available.

Minimum PI	Projects	Communities	Potential Customers	Forecast Customers	Estimated Capital (millions)
0.4	30	34	19,805	9,289	$150
0.5	20	21	7,944	3,942	$49
0.6	14	15	5,994	3,063	$35

- Customer/Municipal Contributions
  - Treatment of TES as flow through revenue defers rate impacts for existing customers, and improves project economics

Potential Projects Enabled Through Proposal

uniongas
A Spectra Energy Company

Community Name		Potential Customers
Milverton		818
Prince Township, Sault Ste Marie		375
Lambton Shores, Kettle Point First Nation	*	496
Walpole Island First Nation- main commercial area	*	83
Moraviantown First Nation- main commercial area	*	70
Lagoon City (Orillia)		2,556
Hidden Valley/Huntsville		100
Santa's Village/Beaumont Dr, Bracebridge		133
Canal, Gravenhurst		166
Northshore Rd / Peninsula Rd North Bay		333
Hornby		115
Oneida First Nation	*	466
Auburn		108
Cedar Springs		175
Astorville		467

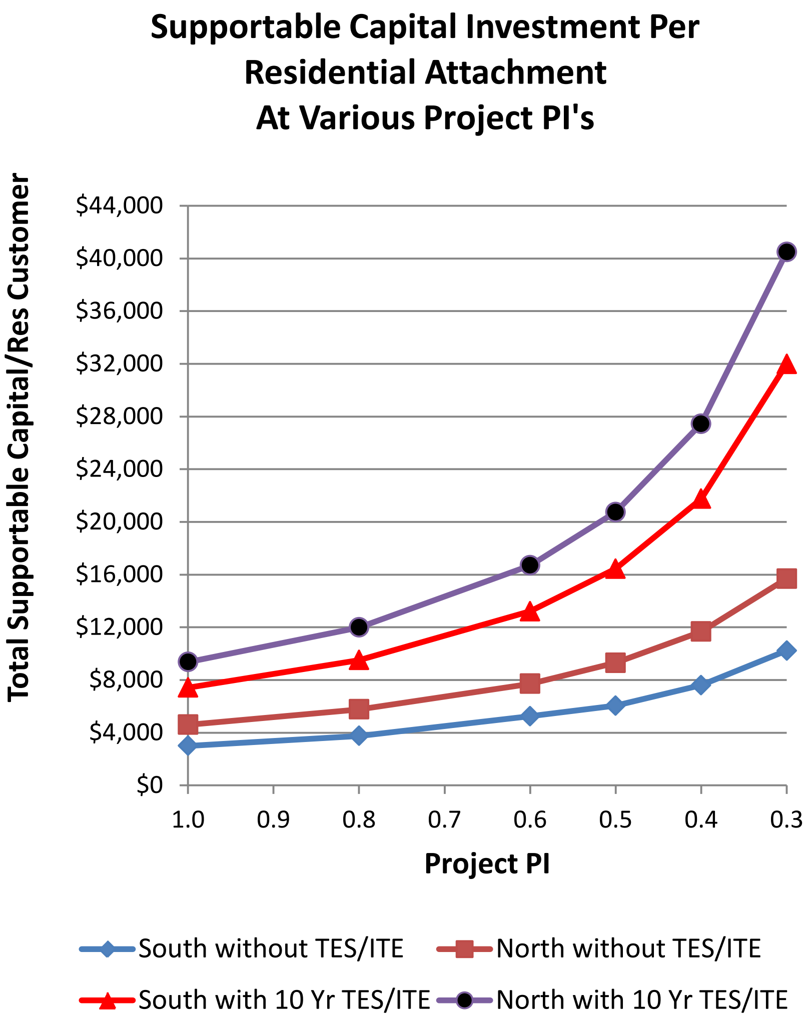
Conditions:
• Minimum project PI = 0.4
• Community Expansion projects excluded from Portfolio PI's
•Approval of TES and ITE

Community Name		Potential Customers
Nipissing First Nation / Jocko Point	*	467
Chippewa of the Thames First Nation- phase 3 & 4	*	110
Sheffield		120
Turkey Point		541
Rockton		125
Chippewas of the Saugeen	*	120
Washago		405
E Floral (T Bay area)		100
Haldimand Shores		150
Latchford, Tri Town		200
Belwood		768
Kincardine. Tiverton, Paisley, Chesley		9,680
Swiss Meadow		108
Boblo Island		300
Village of Warwick		150

* First Nations community

Appendix

EBO 188 Exemptions: Impacts of Reduced Minimum Project PI's

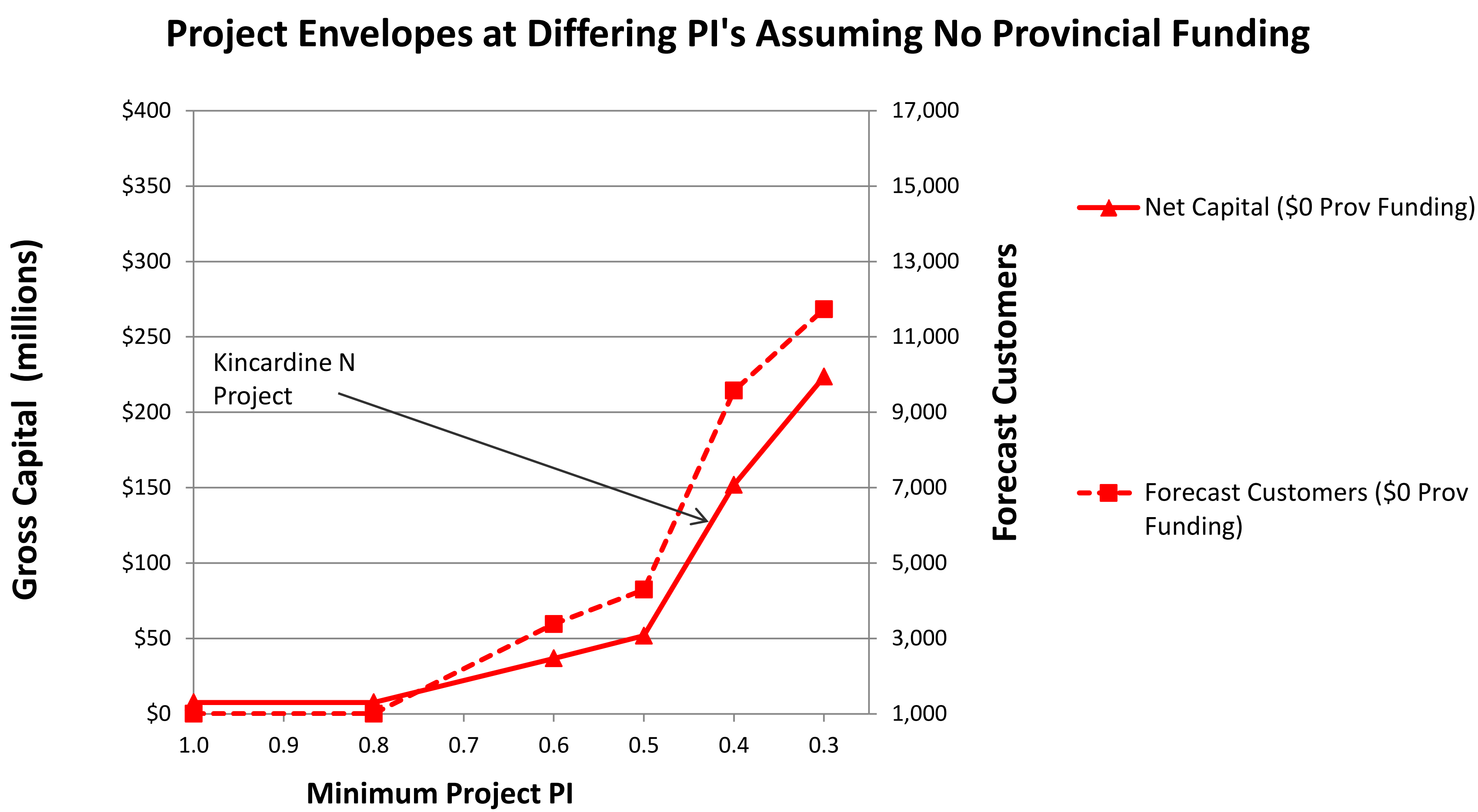


Macro Analysis Approach

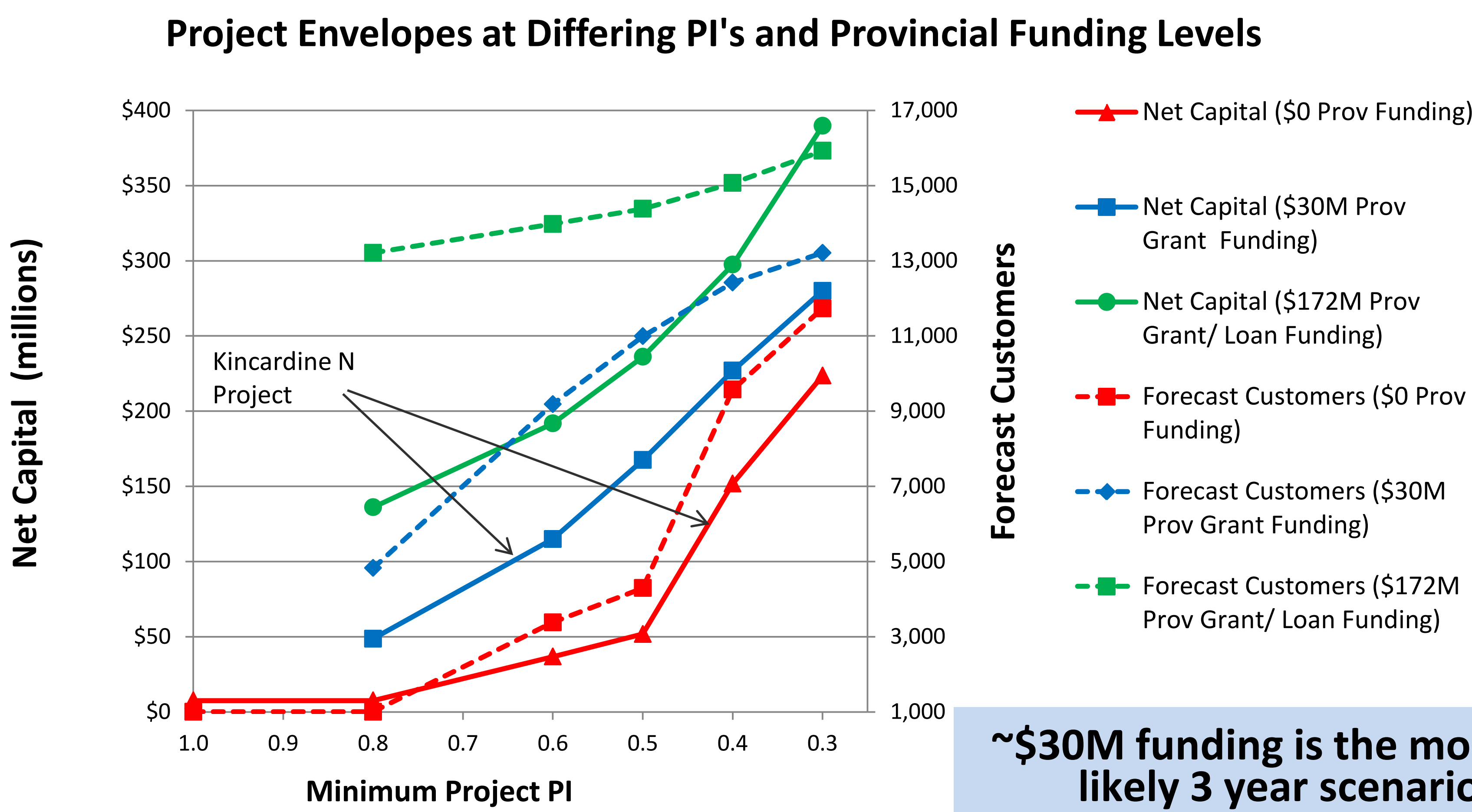
- Determined level of capital investment that an average residential customer's load would support
  - For both base delivery revenue as well as including the new surcharges for 10 years
- Applied results against capital cost per customer for each project from viability sorted project list
  - Included TES/ITE
  - Assumed various levels of provincial funding available

- TES: Volumetric Expansion Surcharge for 10 years
  - ITE: Municipal contribution for 10 years

EBO 188 Exemptions: Results of Analysis



Results of PI Analysis Including Provincial Funding Assumptions



~$30M funding is the most likely 3 year scenario

Customer/Muni Contributions

Treatment as flow through revenue:

- Slightly improves project PI's
  - CCA benefits aren't given up over time
- Much simpler from a tracking perspective
  - Deferred aid alternative required a rate base offset each year as contributions are received
- Gross capital remains in rate base
- Consistent with contract customers, but varies from accepted past practice for mid 1990's era "Market Contribution Charge"

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1

Please explain why Union believes that it is appropriate to require only Union's existing ratepayers, and not all existing Ontario natural gas ratepayers, to subsidize the Community Expansion Projects.

Response:

Please see the response at Exhibit B.Staff.2, Exhibit B.CCC.5 and Exhibit B.Energy Probe.4 c).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p.9, Figure 1

Please provide a long-term forecast for the estimated annual cost of energy. In doing so, please provide all assumptions made, including the effect on the implementation of an Ontario cap and trade system.

Response:

Please see the response at Exhibit B.Energy Probe.5. Union has not factored any future costs of energy into its pre-filed evidence. All comparisons are at prices in place at the time the evidence was filed.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p.16

Union states that one of the barriers to expansion being addressed with the TES is the "the initial financial burden presented by the traditional up-front CIAC mechanism". If this is one of the purposes of the TES, please explain why it does not have a similar regulatory treatment to a CIAC payment, to reduce rate base.

Response:

Please see the response at Exhibit B.LPMA.1 b).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 18

Please provide a copy of the 'Union Gas 2011 Market Share Study'.

Response:

Please see Attachment 1.

strivehigher

2011 Market Share Study

Prepared by Tokunbo Aromiwura, Market Research & Analysis
April 2012

uniongas
A Spectra Energy Company

2011 Single-family Market Share Survey -Methodology

Background

- In addition to measuring penetration of natural gas technologies within Union's residential single-family customers, non-customers with or without access to natural gas were also surveyed to measure conversion potential.

Research Design

- Identified postal codes within Union's service territory were mapped out to publicly available phone numbers. To avoid any bias, the survey was not sponsor identified. Respondents were screened to be single-family households and those who pay their heating bills. The following qualifiers were used to identify the different groups:
  - Customers: Use natural gas in home & Union Gas is their natural gas service provider. (Penetration)
  - Households with access: Have access to natural gas/have gas main running down street/neighbours have natural gas. (Infill customers)
  - Households without access: No access to natural gas but within UG's service territory.

Fielding period

- Telephone interviews were conducted between November 3rd – December 11th, 2011
  - Interviews were conducted by TNS Canada, third-party research supplier.

2011 Single-family Market Share Survey - Respondent Breakdown & Calculated Market Share

strivehigher

	TOTAL Interviews	% Market Share (access)	% Market Share (overall)
Customers	1260	90%	75%
Non-customers with access	146	10%	8%
Non customers without access	202	-	17%
TOTAL	**1608**	**100%**	**100%**

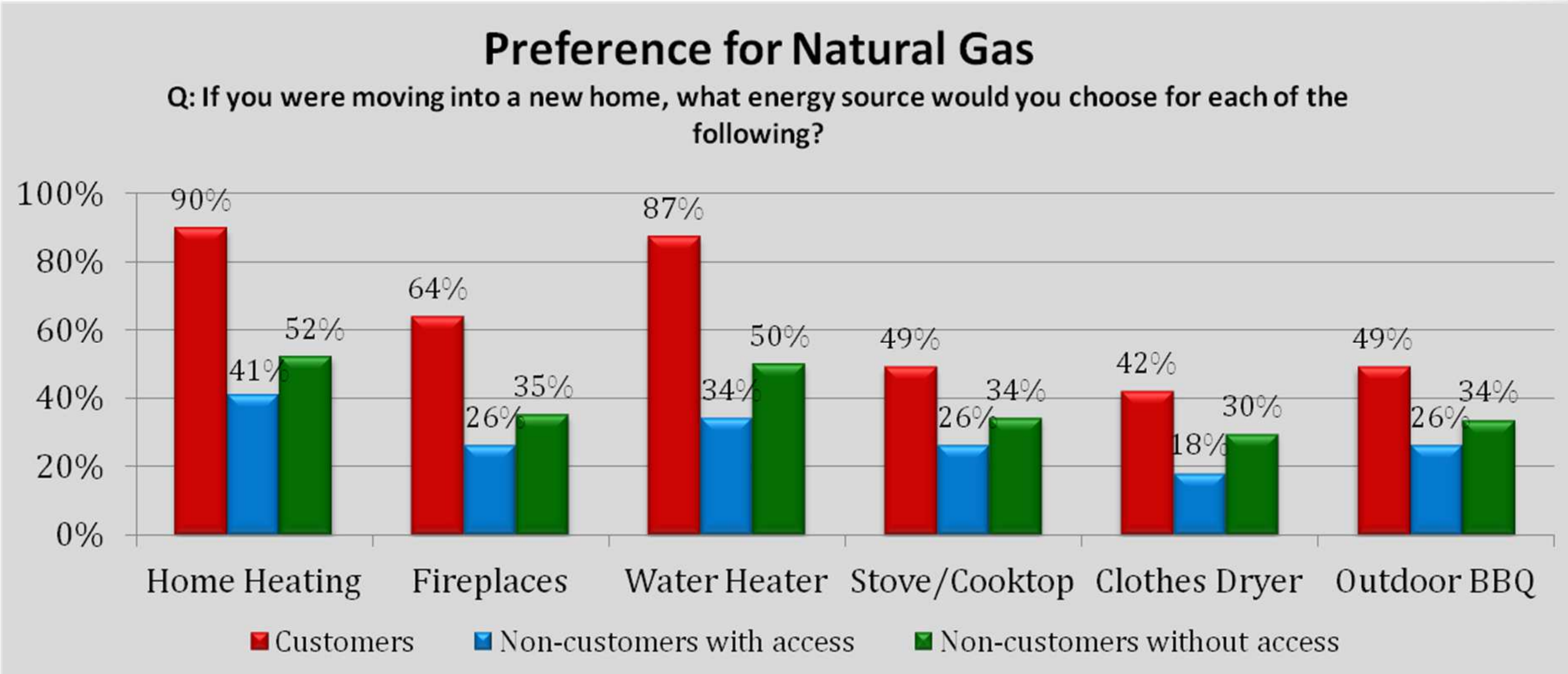
	Market Share (access)
Central	92%
Eastern	78%
Northern	88%
Southwestern	95%

Note: The determination of market share % with and without access is based on weights derived from Statistics Canada census data (2006) for Union's service territory.

uniongas
A Spectra Energy Company

Preference for Natural Gas Appliances
- Customers & Non-customers

strivehigher



- **Non-customers have significantly weaker preference for n.g appliances than customers.**
- **Interestingly, non-customers with access exhibit the weakest preference across all application types.**

- **Among customers, preference for "other" appliances (fireplaces, stoves, clothes dryer, outdoor bbq) is significantly higher than current penetration levels.**
  - Fireplace Penetration: 38%
  - Stoves Penetration: 25%
  - Clothes Dryer Penetration: 21%
  - Outdoor BBQ Penetration: 24%

uniongas
A Spectra Energy Company

Preferred Source of Energy for Home Heating - Non-customers

strivehigher

Preference for Natural Gas as Energy Source for Home Heating

	Non-customers with access	Non-customers without access
Home Heating	**41%**	**52%**
Central	49%	49%
Eastern	50%	52%
Northern	41%	41%
Southwestern	38%	46%

- Irrespective of having access or not, preference for natural gas as energy source for home heating is:
  - highest in the Eastern & central region.
  - highest among propane users.
  - highest among the 55 – 64 age group.

uniongas
A Spectra Energy Company

Current Source of Energy for Home Heating - Non-customers

strivehigher

	Non-customers with access	Non-customers without access
Oil	**29%**	**34%**
Central	27%	35%
Eastern	46%	42%
Northern	15%	26%
Southwestern	24%	32%
Electricity	**44%**	**21%**
Central	39%	18%
Eastern	42%	28%
Northern	55%	14%
Southwestern	65%	20%
Propane	**4%**	**15%**
Central	3%	20%
Eastern	0%	12%
Northern	3%	14%
Southwestern	6%	16%
Wood	**15%**	**27%**
Central	21%	22%
Eastern	13%	14%
Northern	18%	41%
Southwestern	6%	22%

- **Among customers with access to n.g.**
  - 44% use electricity for home heating, 29% use oil, and 4% use propane. 15% use wood.
  - Eastern region is more likely to use oil for home heating.

- **Among customers without access to n.g.**
  - 34% use oil for home heating, 27% use wood, 21% use electricity, and 15% use propane.
  - Eastern region is more likely to use oil for home heating.
  - Northern region is more likely to use wood for home heating (41%).

Note- totals do not add to 100% because "don't know" responses have been included in the base.

uniongas
A Spectra Energy Company

Home Heating Equipment - Non-customers with access

strivehigher

- The type of heating equipment used by non-customers with access to natural gas are:
  - Oil-fired space heating equipments; 92% forced air, 3% combination system
  - Propane-fired space heating equipments; 86% forced air, 14% combination system
  - Electric systems; 60% base boards; 14% forced air, 9% heat pump/hydronic

- The age distribution of forced air furnaces across all energy types:
  - 33% are 5 years old or less
  - 20% are 6 to 10 years old
  - 9% are 11 to 15 years old
  - 18% are 16 to 20 years old
  - 12% are over 20 years old

39% > 10 years

- 13% of non-customers with access to natural gas indicated that they are fairly/very/extremely likely to replace their furnace in the next 2 years; 73% would likely install a n.g furnace.

uniongas
A Spectra Energy Company

Home Heating Equipment
- Non-customers without access

strivehigher

- The type of heating equipment used by non-customers with no access to natural gas are:
  - Oil-fired space heating equipments; 82% forced air, 7% hydronic
  - Propane-fired space heating equipments; 67% forced air, 7% hydronic, 12% space heater
  - Electric systems; 25% base boards; 48% forced air, 15% heat pump/hydronic

- The age distribution of forced air furnaces across all energy types:
  - 32% are 5 years old or less
  - 29% are 6 to 10 years old
  - 19% are 11 to 15 years old
  - 7% are 16 to 20 years old
  - 9% are over 20 years old

35% > 10 years

- 14% of non-customers without access to natural gas indicated that they are fairly/very/extremely likely to replace their furnace in the next 2 years.
  - When asked why natural gas is not the energy source of choice, 85% indicated unavailability of natural gas as main reason.

uniongas
A Spectra Energy Company

Preferred Source of Energy for Water Heater - Non-customers

strivehigher

	Non-customers with access	Non-customers without access
Water Heater	**34%**	**50%**
Central	41%	51%
Eastern	58%	52%
Northern	28%	35%
Southwestern	31%	50%

- Preference for natural gas as energy source for water heating among non-customers with access is highest in Eastern region

- Preference for natural gas as energy source for water heater among non-customers without access
  - lowest in the Northern region.
  - lowest among households with $30,000 income or less (36%).
  - highest among the 55 – 64 age group (54%).

uniongas
A Spectra Energy Company

Current Source of Energy for Water Heater - Non-customers

strivehigher

	Non-customers with access	Non-customers without access
Oil	**10%**	**12%**
Central	3%	20%
Eastern	13%	8%
Northern	8%	6%
Southwestern	6%	10%
Electricity	**83%**	**74%**
Central	88%	65%
Eastern	87%	84%
Northern	90%	80%
Southwestern	81%	66%
Propane	**5%**	**8%**
Central	9%	12%
Eastern	0%	8%
Northern	0%	6%
Southwestern	6%	14%

- **Among customers with access to n.g.**
  - Most common source of energy for water heater across districts is electricity.
  - 13% of water heaters in Eastern are powered by oil.
  - 68% of water heaters are owned, 31% are rented (Central-72%, Eastern-74%, Northern-64%, Southwestern-69%). Among customers, 32% of water heaters are owned.
  - 11% are likely to replace water heater in next 2 years; 46% would likely install a natural gas water heater.

- **Among customers without access to n.g.**
  - Most common source of energy for water heater across districts is also electricity.
  - 75% of all water heater heaters are owned (Central-77%, Eastern-83%, Northern-86%, Southwestern-83%).
  - 14% are likely to replace water heater in next 2 years.

uniongas
A Spectra Energy Company

Preferred Source of Energy for Other Appliances
Non-customers

strivehigher

	Non-customers with access	Non-customers without access
Fireplace	**26%**	**35%**
Central	13%	31%
Eastern	44%	30%
Northern	28%	29%
Southwestern	38%	36%
Cooktop/Stove	**26%**	**34%**
Central	21%	37%
Eastern	33%	20%
Northern	25%	26%
Southwestern	6%	42%
Clothes Dryer	**18%**	**30%**
Central	9%	29%
Eastern	30%	14%
Northern	18%	28%
Southwestern	31%	36%
Barbecue	**26%**	**34%**
Central	21%	31%
Eastern	29%	28%
Northern	25%	33%
Southwestern	13%	38%

- **Among customers with access to n.g.**
  - Preference for other n.g appliances is highest in the Eastern region.

- **Among customers without access to n.g.**
  - Preference for other n.g appliances is highest in the Southwestern region.

uniongas
A Spectra Energy Company

Demographic Profile
- Customers & Non-customers

strivehigher

	Non-customers with access (n=146)	Non-customers without access (n=202)	Customers* (n=1200)
Size of house (in sq ft)			
Less than 1000	16%	9%	9%
1000 to 1499	41%	27%	33%
1500 to 1999	21%	26%	25%
2000 to 2499	6%	15%	15%
2500 or more	11%	17%	10%
When house was built			
Before 1900	4%	9%	4%
1900 – 1949	16%	12%	16%
1950 – 1969	23%	15%	27%
1970 – 1989	37%	26%	30%
1990 – 1999	14%	16%	12%
2000 – 2011	6%	22%	12%
Style of house			
Bungalow/One Story	56%	47%	39%
Raised Ranch	10%	7%	5%
Split Level	4%	7%	12%
Two Story	20%	29%	33%
Three Story	1%	6%	3%
Other Style	8%	3%	7%

Non-customers with access (compared to customers)

- more likely to live in smaller homes (57% vs. 42% - 1499 sq. ft homes or less).
- significantly more likely to live in bungalow/ one story houses.
- The age of house does not differ significantly.

Non-customers without access (compared to non-customers with access)

- more likely to live in larger homes.
- more likely to live in a two-story home.
- more likely to love in newer homes.

*Customer profile from 2010 Penetration study

uniongas
A Spectra Energy Company

Demographic Profile
- Customers & Non-customers

strivehigher

	Non-customers with access (n=146)	Non-customers without access (n=202)	Customers* (n=1200)
Length of residence			
Less than 1 year	1%	1%	4%
1 or 2 years	8%	3%	8%
3 or 4 years	8%	12%	9%
5 to 9 years	25%	26%	18%
10 to 14 years	15%	17%	14%
15 years or more	43%	40%	48%
Location of home			
Rural	43%	64%	20%**
Urban	57%	30%	80%**
Age of respondent			
18 – 34	13%	7%	6%
35 – 44	21%	14%	18%
45 – 54	17%	21%	24%
55 – 64	22%	30%	23%
65+	26%	25%	28%
Household size			
1	19%	19%	15%
2	39%	45%	43%
3 or 4	35%	23%	32%
5 or more	7%	14%	9%
Income			
$30,000 or under	25%	17%	18%
Over 30,000 to 60,000	33%	30%	47%
Over 60,000 to 80,000	15%	17%	24%
Over 80,000	27%	35%	12%

- **Both non-customer groups have higher incomes compared to customers.**
- **No significant difference in length of residence across groups.**
- **Non-customers with access are more likely to be located in an urban area.**
- **Non-customers without access are most likely to be located in rural postal codes.**

**Customer profile from 2010 Penetration study*
***From 2011 Market share study*

uniongas
A Spectra Energy Company

Likelihood of recommending natural gas appliances - Customers & Non-customers

strivehigher

	Customers	Non-customers with access	Non-customers without access
Central	67%	29%	43%
Eastern	68%	50%	34%
Northern	63%	31%	41%
Southwestern	74%	20%	50%
TOTAL	**69%**	**30%**	**43%**

- **Non-customers without access are more likely to recommend natural gas appliances that non-customers with access.**
- **Among non-customers with access, likelihood to recommend n.g appliances is highest in the Eastern region.**
- **Among those without access, likelihood to recommend n.g appliances is highest in the Southwestern region.**

uniongas
A Spectra Energy Company

strivehigher

For The Energy In You

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 18

For each of the 5 proposed projects, please quantify the estimated environmental benefits associated with customers switching to natural gas from another energy source. Please provide details of all calculations and a list of input assumptions.

Response:

Please see the table below for greenhouse gas ("GHG") impacts. For purposes of these calculations, Union assumed conversions at the same rate for each fuel source defined at Exhibit A, Tab 1, p. 18, Table 1 with the exception that Union has assumed wood will not be converted to natural gas because of the limited annual savings when TES costs are factored in.

Table 1: GHG Impacts

Project	**Yr 10 Volume (m^3/yr)**	**Yr 10 Energy (GJ/Yr)**	**Current Fuel Mix (tCO_2e)**	**Natural Gas (tCO2e)**	**% Change (tCO2e)**
Milverton	2,335,388	90,034.3	4,839.63	4,441.05	-8%
Kettle Point/Lambton Shores	749,832	28,907.6	1,553.88	1,425.91	-8%
Prince Township	547,202	22,329.5	1,200.28	1,101.43	-8%
Moraviantown	136,457	5,260.7	282.78	259.49	-8%
Total	**3,800,879**	**146,532.1**	**7,876.88**	**7,227.88**	**-8%**

Overall, there will be various changes in emissions of Criteria Air Contaminants as a result of the conversion to natural gas:

- Nitrogen Oxides: 1% reduction
- Carbon Monoxide: 53% increase
- Particulate Matter: 79% reduction
- Sulphur Dioxide: 81% reduction
- Volatile Organic Compounds: 49% increase

The assumptions and calculations supporting this data are provided at Attachment 1.

End Use Emissions Estimates for Proposed Projects

			GHG						CACs															
Project	Yr 10 volume	Yr 10 energy	Current Fuel Mix (with wood CO_2)	Natural Gas	% Change	Current Fuel Mix (without wood CO_2)	Natural Gas	% Change	Current Fuel Mix	Natural Gas	% Change	Current Fuel Mix	Natural Gas	% Change	Current Fuel Mix	Natural Gas	% Change	Current Fuel Mix	Natural Gas	% Change	Current Fuel Mix	Natural Gas	% Change
	M3/Year	GJ/yr	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e	t CO_2e	kg NO_2	kg NO_2	%	kg CO	kg CO	%	kg TPM	kg TPM	%	kg SO_2	kg SO_2	%	kg VOC	kg VOC	%
Milverton	2,335,388	90,034.3	4839.63	4441.05	-8%	4839.63	4441.05	-8%	3,589.60	3,567.19	-1%	993.81	1,517.95	53%	56.64	11.68	-79%	144.36	27.36	-81%	140.10	208.72	49%
Lambton Shores/Kettle Point	749,832	28,907.6	1553.88	1425.91	-8%	1553.88	1425.91	-8%	1,152.53	1,145.33	-1%	319.09	487.37	53%	18.19	3.75	-79%	46.35	8.79	-81%	44.98	67.01	49%
Prince Township	579,202	22,329.5	1200.28	1101.43	-8%	1200.28	1101.43	-8%	890.26	884.70	-1%	246.48	376.47	53%	14.05	2.90	-79%	35.80	6.79	-81%	34.75	51.76	49%
Moraviantown	136,457	5,260.7	282.78	259.49	-8%	282.78	259.49	-8%	209.74	208.43	-1%	58.07	88.69	53%	3.31	0.68	-79%	8.44	1.60	-81%	8.19	12.20	49%
Sub total	3,800,879	146,532.1	7876.57	7227.88	-8%	7876.57	7227.88	-8%	5842.13	5805.65	-1%	1617.44	2470.49	53%	92.18	19.01	-79%	234.95	44.53	-81%	228.02	339.69	49%
Walpole Island	408,009	15,729.6	845.52	775.88	-8%	845.52	775.88	-8%	627.13	623.21	-1%	173.63	265.20	53%	9.90	2.04	-79%	25.22	4.78	-81%	24.48	36.46	49%
Total with Walpole	4,208,888	162,261.8	8722.09	8003.76	-8%	8722.09	8003.76	-8%	6469.26	6428.86	-1%	1791.07	2735.69	53%	102.08	21.05	-79%	260.17	49.31	-81%	252.50	376.16	49%

CAC Emission Factors	NATURAL GAS (kg/GJ)	FUEL OIL (kg/GJ)	WOOD (kg/GJ)	PROPANE (kg/GJ)	ELECTRICITY (kg/GJ)
CARBON MONOXIDE	0.0169	0.0155	2.2778	0.0169	*For CAC's, conservatively assume none, although will be some at fossil and biomass generation facilities.*
OXIDES OF NITROGEN (EXPRESSED AS NO_2)	0.0396	0.0557	0.0436	0.0613	
SULPHUR DIOXIDE	0.0003	0.0031	0.0087	0.0005	
TOTAL PARTICULATE MATTER	0.0001	0.0012	0.3535	0.0001	
VOLATILE ORGANIC COMPOUNDS	0.0023	0.0022	0.3273	0.0023	

GHG Emission Factors	Natural Gas (g/GJ)	Fuel Oil (g/GJ)	Propane (g/GJ)	Wood (g/kg fuel)	Eletricity (g CO_2e/kWh)
CO_2	49030	70230	59660	1696	80
CH_4	0.966	0.67	1.067	15	
N_2O	0.913	0.799	4.267	0.16	

Fuel Breakdown			
Fuel Type	Initial Fuel Mix	Adj Current Fuel Mix	Future Fuel Mix
Fuel Oil	35%	49%	-
Electricity	22%	31%	-
Propane	15%	21%	-
Wood	28%	0%	-
Natural Gas	0%	0%	100%
Excl wood:	72%		

Global Warming Potentials	CO2	CH4	N2O
Used in Calcs	1	25	298

Assumptions: End Use Emissions Estimates

* The forecasted year 10 natural gas volumes are converted to an energy basis using the 2014 Union Gas average energy content (see 'HHV' tab)
* The comparison assumes that the energy consumption before conversion is equal to the after conversion projections for natural gas.
  This is a conservative assumption that does not account for the improvement in equipment energy efficiency that new natural gas fired equipment will provide
* With the exception of electricity related GHG emissions, the comparison looks at end use emissions only
* Pre-conversion fuel sources are assumed to have the following breakout:

Fuel Oil	35%
Electricity	22%
Propane	15%
Wood	28%

* For natural gas criteria air contaminants (CAC) estimates, the CEPEI Emission Calculator CAC emission factors ("Residential Boilers/Furnaces") are used.
  Aside from Environment Canada approved PM emission factors, these emission factors are based on EPA AP-42 (with adjustments for fuel sulphur content)
  The Sulphur content assumed for fuel oil is 0.5%, the maximum sulphur content permitted in Ontario for grades 1 and 2
  A sulphur content of 5.5 mg/m3 was assumed for natural gas (odorized gas)
* Use CEPEI Emissions Calculator for CAC emission factors ("Residential Boilers/Furnaces"), mostly AP42
* As per AP-42 ('Propane' tab) assume that PM, CO & TOC emission factors for propane are the same as for natural gas (use Natural Gas emission factors from CEPEI Combustion Calculator)
* For CAC's, conservatively assume none for electricity, although there will be some due fossil and biomass generation facilities.
* GHG emission factors are based on Ontario's Guideline for Greenhouse Gas Emissions Reporting or Environment Canada's National Inventory Report
* Note that for GHGs, biofuels such as wood can be considered carbon-neutral since carbon dioxide was absorbed from the atmosphere as the trees were growing
  The comparison show the results with and without CO_2 from wood in the calculation

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 20

Please provide a copy of the market surveys Union undertook in Milverton and Price Township.

Response:

Please see the response at Exhibit B.Staff.11.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p.22

Please explain the mechanism that Union will collect the ITE from municipalities.

Response:

Please see the response at Exhibit B.CPA.12.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 25

Is it Union's view that the only reason a PI of 0.4 is appropriate is because it allows for a large number of projects to become feasible? Please explain why a PI of 0.4 was the appropriate minimum profitability level.

Response:

In developing its proposal Union was attempting to strike a balance between the numbers of potential customers who could gain access, and the impact on existing ratepayers. As noted at Exhibit A, Tab 1, p. 25, Figure 4, the net capital per potential customer escalates significantly below a P.I. of 0.4, and the number of potential customers begins to taper off. The impact to existing ratepayers would escalate with this increase in capital at a minimum P.I. of 0.3, and for that reason Union has proposed a minimum P.I. of 0.4. Please also see the response at Exhibit B.CPA.14.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 26, 35

Please provide a list of 'Immediate Community Expansion Opportunities' ordered by project PI.

Response:

Union has assumed with this response that the request is for the list of Projects to be sorted by their "natural P.I.", which would be the P.I. in the absence of TES, ITE, or any Aid-to-Construction. This list is included in Attachment 1. The row numbers in Attachment 1 correspond to the row numbers in Exhibit A, Tab 1, Appendix D.

Opportunity Assessment Summary

											Including TES/ITE					
											Min PI= 0.4		Min PI= 0.5		Min PI=0.6	
Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (milllions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)
3	Lambton Shores, Kettle Point First Nation	2	496	281	6	1.65	$1.79	$3,615	0.42	$0.79	48		48		48	
6	Lagoon City (Orillia)	1	2,556	1,150	19	2.61	$14.19	$5,553	0.42	$4.09	48		48		63	
2	Prince Township, Sault Ste Marie	1	375	242		0.48	$2.72	$7,243	0.38	$0.60	48		48		82	
7	Hidden Valley/Huntsville	1	100	46		0.10	$0.65	$6,452	0.38	$0.16	48		48		72	
8	Santa's Village/Beaumont Dr, Bracebridge	1	133	60	6	0.14	$0.86	$6,470	0.36	$0.21	48		49		84	
5	Moraviantown First Nation- main commercial area	1	70	61	5	0.10	$0.49	$7,011	0.35	$0.11	48		48		50	
9	Canal, Gravenhurst	1	166	74	2	0.17	$1.17	$7,070	0.33	$0.27	48		63		98	
10	Northshore Rd / Peninsula Rd North Bay	1	333	150		0.34	$2.34	$7,030	0.33	$0.53	48		73		109	
1	Milverton	1	818	526	21	1.64	$4.77	$5,827	0.32	$1.31	48		48		50	
15	Astorville	1	467	210	5	0.48	$3.71	$7,951	0.29	$0.75	49		87		120	$0.21
16	***Brenman Line, Servern Twp (Gravenhurst)	1	33	14	2	0.03	$0.24	$7,396	0.29	$0.05	56		108		120	$0.02
12	Oneida First Nation	1	466	210	5	0.48	$2.20	$4,720	0.28	$0.75	48		72		96	
17	Nipissing First Nation / Jocko Point	1	467	210		0.48	$3.92	$8,383	0.28	$0.75	60		97		120	$0.44
13	Auburn	1	108	49	8	0.11	$0.53	$4,878	0.27	$0.17	48		61		86	
14	Cedar Springs	1	175	79	1	0.18	$0.90	$5,121	0.25	$0.28	48		74		98	
24	Washago	1	405	182	6	0.41	$4.14	$10,232	0.23	$0.65	88		120	$0.48	120	$1.25
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	4,250	87	13.31	$66.25	$7,952	0.23	$15.12	84		120	$1.90	120	$15.74
18	***Munsee Delaware First Nation	1	42	19		0.04	$0.27	$6,412	0.21	$0.07	63		96		120	$0.02
19	Chippewa of the Thames First Nation- phase 3 & 4	1	110	50		0.11	$0.72	$6,556	0.21	$0.18	64		97		120	$0.06
25	E Floral (T Bay area)	1	100	46	2	0.10	$1.08	$10,835	0.21	$0.16	84		120	$0.08	120	$0.29
20	Sheffield	1	120	54	3	0.12	$0.78	$6,496	0.20	$0.19	70		99		120	$0.07
21	Turkey Point	1	541	244	12	0.65	$3.65	$6,749	0.20	$0.87	83		118		120	$0.69
26	Haldimand Shores	1	150	68	6	0.15	$1.80	$12,011	0.20	$0.24	105		120	$0.16	120	$0.37
27	Latchford, Tri Town	1	200	90	6	0.20	$2.34	$11,702	0.20	$0.32	111		120	$0.58	120	$0.95
22	Rockton	1	125	57	4	0.13	$0.88	$7,072	0.19	$0.20	79		112		120	$0.16
23	Chippewas of the Saugeen	1	120	54	5	0.12	$0.87	$7,290	0.19	$0.19	83		119		120	$0.17
28	Belwood	1	768	346	17	0.78	$5.79	$7,538	0.18	$1.23	95		120	$0.61	120	$1.71
11	Hornby	1	115	64	1	0.05	$1.22	$10,640	0.16	$0.18	77		111		120	$0.23
30	***Little Longlac	1	14	7	1	0.02	$0.25	$17,882	0.16	$0.02	120		120	$0.07	120	$0.11
31	Swiss Meadow	1	108	49	1	0.11	$1.02	$9,422	0.15	$0.17	111		120	$0.24	120	$0.40
32	Boblo Island	1	300	136	1	0.31	$2.66	$8,875	0.15	$0.48	117		120	$0.72	120	$1.14
33	Village of Warwick	1	150	69	13	0.30	$1.48	$9,896	0.14	$0.24	120		120	$0.41	120	$0.64
4	~~Walpole Island First Nation- main commercial area~~	Removed from application														
	TOTALS- All Projects	136	43,735	20,606			$1,536.75	$35,137	12.82	$72.03		$704.54		$842.67		$975.67

* Project profitabilty index (P.I.) based on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.

** Simplified calculation assuming residential NAC for all customers and no contract customer volumes.

*** Project does not meet definition of Community Expansion Project so would not be eligible for reduced PI without additional project scope.

Kincardine and Hornby data are revised in comparison to Exhibit A, Tab 1, Appendix D.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 26

Please explain in detail the process Union undertook to explore community expansion opportunities.

Response:

The intent of including all the potential Projects in evidence was to allow the Board to understand the magnitude of future rate impacts if all potential Projects were to proceed over several years. Before making any decision to propose installation of any Projects beyond the initial five proposed in Exhibit A, Tab 2, Union would undertake a detailed analysis of the feasibility of each of the Projects prior to requesting the approval to include the costs in rates. The list provided in Exhibit A, Tab 1, Appendix D is not meant to be a definitive list of which communities Union would explore in more detail.

Union initiated the Assessment by asking local District employees to identify potential Community Expansion Projects where one of the following conditions existed:

- An economic feasibility investigation had occurred in the past.
- Where they were aware of interest being expressed by either customers or their elected representatives.
- Other known opportunity areas.

A total of 159 communities were identified throughout this process. Union then applied its judgment and experience to determine which of the identified communities it should initiate the high level feasibility analysis for. This decision was based on the distance of the community from the existing system and the size of the community. There were 138 communities that remained on the list after applying this initial screen.

Some of the communities excluded include Wawa, Chapleau, and a number of smaller communities on Manitoulin Island. Union notes that not including some of these communities in the Analysis presented in Exhibit A, Tab 1, Appendix D does not suggest that they will never obtain natural gas service. Union simply did not include them because the community size in combination with the distance from the existing system suggested that they would be less economically feasible than the communities that remained on the list. These communities may at some point be better candidates for other technologies like a CNG or LNG supplied distribution system. Please see the response at Exhibit B.FRPO.1 for an overview of these types of systems.

Union also did not attempt to include very remote northern “off the grid” communities in the opportunity assessment. These communities are not connected to the electricity grid and are often powered by electricity produced from a diesel fuelled generator. Union believes these communities have a very high propensity of electric baseboard heating systems. Consequently, Union views these communities as potential diesel generation displacement opportunities rather than natural gas distribution opportunities.

Union proceeded to bundle the remaining communities into Projects based on proximity and develop feasibility estimates as described in Exhibit A, Tab 1, Appendix D, pp. 4-5. These estimates were primarily based on “table top” assessments, unless Union had recently (in the last couple of years) undertaken a more detailed feasibility study. A “table top” approach can best be described as developing economic modelling inputs based on readily available public information, for example rooftop counts off aerial mapping, scaling distances off maps, or using previously accepted inputs like normalized annual consumption, or the franchise wide ratio of commercial to residential customers.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p.26

Please provide any presentations, meeting notes, agenda, and any other documents that were exchanged between Union and any the communities of Milverton, Price Township, Chippewas of Kettle and Stony Point First Nation, and Lambton Shores.

Response:

Please see Attachment 1.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 26

Please provide any agreements, memorandum of understandings, letters of intents, between Union and any communities of Milverton, Price Township, Chippewas of Kettle and Stony Point First Nation, and Lambton Shores.

Response:

Please see the response at Exhibit B.Energy Probe.1 b).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab1, p. 31

Please provide the forecast net delivery revenue requirement for each of the 5 proposed projects.

Response:

Please see the response at Exhibit B.EnergyProbe.19 a).

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 31

Please explain why Union believes it should not be exposed to financial risk related to the incremental capital investment required for Community Expansion Projects, when it is seeking an exemption from EBO 188.

Response:

Please see the responses at Exhibit B.CPA.11 and Exhibit B.CPA.16.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 31

Please explain how this application meets each of the requirements of the Capital Pass-Through Mechanism of the 2014-2018 IRM framework.

Response:

As stated at Exhibit A, Tab 1, p.11 (Section 4.5), the purpose of the capital pass-through mechanism proposed in this Application is to recover the Community Expansion Project capital costs when these expansion Projects come into service. The capital pass-through approved as part of Union's 2014-2018 IRM has a similar intent in that it allows Union the ability to adjust rates during the IRM term to reflect the associated impacts of significant capital investments made throughout the IRM term. Such investments, deemed "not business as usual", refer to capital expenditures that are significant and cannot be managed within Union's Board-approved capital budget. However, the capital pass-through mechanism proposed in this application does not, nor is it intended to meet each of the specific requirements of the IRM capital pass-through mechanism. Although Community Expansion Projects are, for the most part, relatively small in size, consistent with those projects that meet the IRM capital pass-through requirements, Union would not proceed with these Community Expansion Projects without reasonable certainty of cost recovery. Further, this cost recovery certainty will support Union's effort to respond to the immediacy of the government's desire to expand natural gas distribution systems. Union has proposed a deferral account for all net revenue requirement variances from the projects to ensure that Union only earns its allowed ROE from these investments during the IRM term. Please see the response at Exhibit B.CCC.14 for additional detail.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, p. 45

Please explain how Union forecasted the number of customers for each project? Please provide all assumptions made.

Response:

In developing the forecast for each project, Union reviewed surveys that were completed by Forum Research Incorporated, historical attachment rates, discussions with Municipal officials and Union's local knowledge of the areas.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, Appendix D

With respect to the Opportunity Assessment Summary:

a) Please provide a breakout of both the potential and forecast customers, by the number of customers that are:

   i. Residential
   ii. Small commercial
   iii. Medium commercial
   iv. Large commercial
   v. Other

b) How does the ratio between potential and forecast customers compare to Union's past experience with connecting new communities?

Response:

a) The customer forecasts for each of the four Projects in Exhibit A, Tab 2 are included as Schedules in their respective Tabs.[1]

   Union will file the customer forecast information for the other Projects when approval is sought for rate recovery for each of these Projects.

b) Union has taken a conservative approach to forecasted conversions, as noted in the response at Exhibit B.South Bruce.6.

   Union compared its forecasted 45% attachment rate assumptions to several prior Community Expansion Projects. The Projects used in this comparison were all completed well over a decade ago. The four Projects investigated included the following:

   - Parry Sound

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

- Wingham
- Clifford/Mildmay/Formosa
- Port Elgin/Southhampton/Wingham

These four Projects collectively had 9,126 customers attach in the 10 year customer forecast period out of a potential of 16,495 homes and businesses, which represents 55% of potential customers being attached[2]. Union notes that these projects went into service approximately 15 years or more ago, and that the potential savings from converting to natural gas from other fuels has increased since that time. In 2000, as shown in Table 1 below, estimated annual savings ranged from $658 to $1207, in comparison to a range of $1,683 to $2,175 in 2015[3]. Based on this it could be reasonably predicted that conversion rates today would increase beyond 55%.

Table 1: Annual Costs of Energy in Year 2000

	Northern Ontario	Southern Ontario	Average Ontario	Savngs from Natural Gas
Natural Gas	$ 827	$ 694	$ 728	
Propane (automotive)	$ 1,591	$ 1,317	$ 1,386	$ 658
Furnace Oil	$ 1,226	$ 1,206	$ 1,211	$ 483
Electricity	$ 1,834	$ 1,969	$ 1,935	$ 1,207

Sources:

Propane & Heating Oil: The Kent Group. Rates taken for London for the South and Thunder Bay for the North

Natural Gas: Union Gas Limited Rate Schedules

NG Savings:

Propane (automotive)	$ 764	$ 623	$ 658
Furnace Oil	$ 398	$ 511	$ 483
Electricity	$ 1,006	$ 1,274	$ 1,207

[2] Details are provided at Exhibit B.Staff.12.
[3] Refer to Exhibit B. CPA.1 Attachment 1 for 2015 savings estimates.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 1, Appendix K

For each rate class, please provide the annual bill impact a customer will pay for the 30 potential projects on a per new customer basis.

Response:

Please see Exhibit B.CCC.21 for the 2018 bill impacts for in-franchise rate classes of the 29 potential Community Expansion projects including the TES and ITE deferral credits.

Please see Attachment 1 for the 2018 bill impact for each rate class on a per new customer basis.

UNION GAS LIMITED
Impacts of the 29 Potential Community Expansion Projects Including TES and ITE Deferral Credits
Bill Impact on a per New Customer Basis

Line No.	Particulars	Annual Bill Impacts (1) ($)	Bill Impact Per New Customer (2) ($)
		(a)	(b)
	Union South		
1	Rate M1	4.04	0.00
2	Rate M2		
3	Small	54	0.02
4	Large	172	0.06
5	Rate M4		
6	Small	665	0.22
7	Large	7,542	2.54
8	Rate M5		
9	Small	1,473	0.50
10	Large	10,609	3.57
11	Rate M7		
12	Small	10,751	3.62
13	Large	46,915	15.79
14	Rate M9		
15	Small	41	0.01
16	Large	121	0.04
17	Rate M10	63	0.02
18	Rate T1		
19	Small	2,972	1.00
20	Average	4,747	1.60
21	Large	10,962	3.69
22	Rate T2		
23	Small	4,063	1.37
24	Average	6,695	2.25
25	Large	9,614	3.23
26	Rate T3	1,336	0.45

Notes:
(1) Bill impacts for in-franchise rate classes per Exhibit B.CCC.21, Attachment 1.
(2) The estimated number of new customers for the 29 potential community expansion projects is 2,972 in 2018.

UNION GAS LIMITED
Impacts of the 29 Potential Community Expansion Projects Including TES and ITE Deferral Credits
Bill Impact on a per New Customer Basis

Line No.	Particulars	Annual Bill Impacts (1) ($)	Bill Impact Per New Customer (2) ($)
		(a)	(b)
	Union North		
1	Rate 01	0.71	0.00
2	Rate 10		
3	Small	124	0.04
4	Large	337	0.11
5	Rate 20		
6	Small	2,294	0.77
7	Large	6,931	2.33
8	Rate 100		
9	Small	7,011	2.36
10	Large	53,451	17.98
11	Rate 25	1,339	0.45

Notes:
(1) Bill impacts for in-franchise rate classes per Exhibit B.CCC.21, Attachment 1.
(2) The estimated number of new customers for the 29 potential community expansion projects is 2,972 in 2018.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: p. 4 of the KMPG Report

Please explain why in light of the 'Key Findings' (p.4) of KMPG Report, *Jurisdictional Review of Natural Gas Distribution System Expansions*[1], Union believes its proposed application is appropriate.

Response:

It is unclear to Union the context in which the question is being posed. Union's proposal is a direct response to the government's desire to complete the maximum number of projects, and the Board's invitation to propose plans.

The KPMG report referenced provides a summary of what has occurred in other jurisdictions with a focus towards "onboarding new franchise areas and new entrants"[2]. Union is not a new entrant. Each of the jurisdictions reviewed have differing existing guidelines which may or may not be similar to E.B.O. 188 in Ontario. The existing framework in each area will have some impact on the potential longer term benefits of expansion to a utility's existing ratepayers. This is also referenced in the response at Exhibit B.CCC.5. The report does note a number of jurisdictions, though, that appear to support some degree of cross-subsidization from existing ratepayers to help fund expansion[3]. These include Mississippi, Nebraska and Ohio.

[1] http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/report_KPMG_Natural_Gas_Expansions.pdf
[2] KPMG Report, Jurisdictional Review of Natural Gas Distribution System Expansions, p.1
[3] KPMG Report, Jurisdictional Review of Natural Gas Distribution System Expansions , p.53

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 2

Please provide the Residential Survey script and full results for each of the 5 proposed projects.

Response:

Please see the response at Exhibit B.Staff.11.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Reference: Exhibit A, Tab 3

Please explain the rationale for having different PI qualification for the Community Expansion projects and the Small Main Expansion projects.

Response:

Please see the responses at Exhibit B.LPMA.5 d) and Exhibit B.VECC.11.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, pp. 15-21
Temporary Expansion Surcharge (TES)

Preamble: Please confirm the following details with respect to the TES. For any details that are not confirmed, please provide clarifying information.

a) If Union's proposal is accepted, the proposed rate ($0.23 per m3) will not be adjusted in future rate applications.
b) The term of the TES will be fixed in advance on a project-by-project basis based on Union's forecast of the number of customers that will connect while the TES is being collected, the timing of those customer connections and the average volume consumed.
c) The actual total amount of the TES collected for each project will depend on the actual number of customers that will connect while the TES is being collected, the actual timing of those customer connections and the actual average volume consumed.
d) Hence, actual TES collected will vary from the amount that is forecast to be collected.

Response:

a) Confirmed.

b) Confirmed.

c) Confirmed. To clarify, the actual number of customers is the number of general service customers.

d) Confirmed.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, pp. 22-23 and Municipal Act
Incremental Tax Equivalent (ITE)

Please provide and describe the legal basis that addresses whether municipalities have the authority to contribute to project feasibility by means of the Incremental Tax Equivalent as proposed by Union? If Union has received a legal opinion on this matter please provide it.

Response:

Acceptance of the ITE will require a commercially binding agreement under which the municipality agrees to pay an annual amount to Union. The ITE is not an agreement to avoid the assessment or the payment of required property taxes. That process will not be affected by Union's proposal. Municipalities make commercially binding agreements to pay for services from a wide variety of organizations on a routine basis, and this agreement would be no different. Union has structured its proposal in this way to avoid a need for changes in any tax laws or regulations. The amount that the municipality will be required to agree to contribute each year will be based on the amount equivalent to the additional annual tax assessment that the facilities installed as a result of the project would generate for the municipality.

Please also see the responses at Exhibit B.CPA.12 and Exhibit B.EGD.4.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, p. 23-31
EBO 188 Exemption

Preamble: Please provide the following supporting information related to the implications of the proposed EBO 188 exemption for each of the five initial proposed Community Expansion projects identified at Exhibit A. Tab 1, p. 45, Table 8 and also for the Kincardine, Tiverton, Paisley, Chesley project which appears as number 29 in the list in Exhibit A, Tab 1, Appendix D, p. 1.

a) The annual subsidy for each year over the horizon of the feasibility test calculated as the difference between the forecast revenue and the incremental revenue requirement. Provide the assumption used to project annual revenues.
b) The present value of the annual subsidies as calculated in part a) above.
c) The projected number of years until the distribution revenue associated with each project will equal the incremental revenue requirement. Provide the assumption used to project annual revenues.

Response:

a) Union has interpreted the question to request the net revenue requirement (revenue requirement less incremental distribution revenue less TES and ITE). The net revenue requirement is based on current rates (e.g. no rate increases for 40 years) and the TES/ITE as described in Exhibit A, Tab 1. Please see Attachment 1.

b) Please see Attachment 1.

c) Please see Attachment 1.

Table 1: Revenue Requirement Deficiency(Excess) after TES, ITC (Dollars in $ 000's)

Line	Project	40 Yr NPV Rev Req'mt (a)	First Yr of Surplus (b)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	Milverton	2,426	3	70	113	(45)	(104)	3	263	254	244	235	225	215	208	204	199	194	189	184	179	174	168
2	Moraviantown	270	3	7	10	(7)	(9)	2	26	26	26	25	25	24	24	23	23	22	22	21	21	20	20
3	Lambton Shores -Kettle Point	589	3	30	53	(9)	(35)	(22)	19	14	36	74	70	66	63	62	60	58	57	55	53	51	49
4	Prince Township	980	38	4	121	78	51	78	151	148	144	93	55	52	49	48	46	45	43	42	40	39	37
5	Kincardine	46,652	39	1,664	4,233	3,357	2,794	2,483	2,220	1,959	1,706	1,447	1,180	2,044	4,089	4,019	3,946	3,871	3,793	3,713	3,630	3,546	3,460

For pagination purposes, the same table above with 2nd 20 years is shown below

Line	Project	40 Yr NPV Rev Req'mt	First Yr of Surplus	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
6	Milverton			175	194	189	184	179	173	168	163	158	152	146	139	132	124	117	110	102	20	(49)	(50)
7	Moraviantown			21	23	22	21	21	20	19	18	18	17	16	15	15	14	13	12	12	1	(5)	(5)
8	Lambton Shores -Kettle Point			51	56	53	51	48	46	44	41	39	36	34	31	29	26	23	21	18	(14)	(35)	(35)
9	Prince Township			30	32	31	30	28	26	24	22	20	18	20	18	16	13	11	9	7	(17)	(32)	(33)
10	Kincardine, Tiverton, Paisley, Chesley			3,376	3,306	3,241	3,163	3,076	2,985	2,894	2,801	2,707	2,613	2,516	2,415	2,310	2,205	2,099	1,992	1,882	498	(398)	(401)

Table 2: Sensitivity analysis Revenue Requirement Deficiency(Excess) after TES, ITC based on an annual 1.5% rate increase (Dollars in $ 000's)

Line	Project	40 Yr NPV Rev Req'mt (a)	First Yr of Surplus (b)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
11	Milverton	1,718	3	70	113	(48)	(109)	(5)	252	239	225	211	196	182	170	162	153	144	135	126	116	106	96
12	Moraviantown	211	3	7	10	(7)	(9)	1	25	24	24	23	22	22	21	20	19	18	17	17	16	15	14
13	Lambton Shores -Kettle Point	278	3	30	53	(10)	(37)	(26)	14	8	28	64	58	53	48	45	42	38	35	31	28	24	20
14	Prince Township	484	21	4	119	75	45	71	142	136	130	76	36	29	24	21	17	14	10	6	2	(2)	(6)
15	Kincardine, Tiverton, Paisley, Chesley	41,905	38	1,664	4,230	3,344	2,765	2,436	2,154	1,870	1,592	1,306	1,007	1,841	3,858	3,764	3,667	3,566	3,463	3,357	3,249	3,138	3,025

For pagination purposes, the same table above with 2nd 20 years is shown below

Line	Project	40 Yr NPV Rev Req'mt	First Yr of Surplus	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
16	Milverton			104	129	122	114	106	98	90	82	73	65	56	45	33	22	11	(0)	(12)	(98)	(171)	(177)
17	Moraviantown			15	18	17	16	15	14	13	12	11	10	9	8	7	6	4	3	2	(8)	(15)	(16)
18	Lambton Shores -Kettle Point			21	27	23	19	15	11	7	3	(1)	(5)	(10)	(14)	(19)	(23)	(28)	(32)	(37)	(71)	(94)	(96)
19	Prince Township			(14)	(14)	(17)	(21)	(25)	(29)	(33)	(38)	(42)	(47)	(48)	(53)	(58)	(63)	(68)	(73)	(78)	(104)	(122)	(126)
20	Kincardine, Tiverton, Paisley, Chesley			2,917	2,832	2,754	2,660	2,551	2,438	2,325	2,210	2,094	1,978	1,857	1,730	1,597	1,463	1,327	1,191	1,052	(363)	(1,290)	(1,325)

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, p. 32-33
Related Deferral Accounts

Preamble: Please confirm the following implications of the Community Expansion Contribution Deferral Account. For any implications that are not confirmed, please provide a clarifying explanation.

a) It will ensure that any over or under recovery of the forecast amounts of TES and ITE is flowed through to all Union ratepayers.
b) It will not require any changes to the existing Rolling Project Portfolio (RPP) methodology since the TES and ITE are the equivalent of the CIAC collected for expansion projects subject to the EBO 188 methodology.
c) The collection of TES and ITE differs from the collection of CIAC in that variances will be captured in the deferral account rather than being reflected in the net rate base used for rate setting purposes.

Response:

a) Confirmed.

b) The Community Expansion Contribution Deferral Account (CECDA) will not require any changes in the RPP because Union is proposing that Community Expansion Projects not be included in the RPP. The TES and ITE are not equivalent to an Aid-to-Construction (CIAC). They are sources of revenue.

   Please also see the response at Exhibit B.LPMA.1 b).

c) Not confirmed. The actual amount of TES and ITE collected will be captured in the variance account, not variances between forecast and actual TES and ITE.

   Union's traditional CIAC mechanism would require up-front contributions from all customers who will connect to the system. In other words, Union would require the CIAC prior to construction from a customer who expects to connect immediately as well as a customer who expects to connect several years later. In this case, there would be no variance between the forecast and actual CIAC.

In this "collect in advance" case, the CIAC would be collected in advance from all prospective customers prior to commencement of construction. This approach, however, is impractical for a group of unrelated parties such as homeowners in a new area. A common outcome is for the expected number of customers to decline by the time the payment is required; the remaining customers are required to fund the difference through additional up-front CIAC in order for the project to remain feasible prior to construction, and "free riders" connect at a later date without having to pay CIAC.

Assuming some form of CIAC mechanism where the CIAC is to be collected from any future attachments only upon their actual attachment, a variance between forecast CIAC and actual CIAC could occur in the same way a variance could occur with the proposed TES and ITE.

In this case, where the aid is "collected at time of service request" then a similar variance can occur between the original forecasted timing and number of customers, relative to actual results. This variance is the natural outcome of predicting a reasonable rate and timing of attachment and having an actual result that is either higher or lower than a forecast made some months or a year in advance.

Union proposes that variances in TES and ITE will be collected in the CECDA for disposition to all ratepayers.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, pp. 39-40, Appendix D
Future Community Expansion Projects

Preamble: Please expand on the prospects of proceeding with all 30 potential Community Expansion Projects so that they are in service by 2018 acceptable.

a) What are the prospective in-service dates for each community if the expansions are to be completed by 2018?

b) Confirm that Union considers the revenue requirement and rate impacts of completing the expansion by 2018 to be reasonable.

c) Assuming Union's Community Expansion Project proposal is accepted in its entirety, please identify any factors that might result in a delay in completing the 30 projects by the prospective dates identified in part (a) above.

d) Please confirm whether there is existing capacity on Union's system to supply Lucknow and Ripley from its Wingham facilities.

Response:

a) Union is currently developing plans on resourcing needs and approach required to undertake detailed feasibility analysis to complete the remaining 25 Projects within three years from a Board Decision. Those plans are not yet finalized. On a general basis, the parameters for this planning effort provided for approximately 50% of the required capital to be expended in each of 2017, 2018 and 2019. With early approval of its proposals, Union would consider whether some of the smaller Projects could be completed in 2016.

b) If all 30 Projects become feasible and are completed, Union believes the expected rate impacts are reasonable.[1]

c) There are a number of factors that can affect when or if the remaining Projects can be completed:

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under E.B.O. 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

- The results of detailed cost analysis, agreement on running lines for the mains, market forecast surveys, and environmental assessments required for the Projects, which will all affect the final economic feasibility analysis;
- Capital availability;
- Internal resource requirements;
- External construction resource needs; and
- Municipal agreement to pay ITE.

As outlined in Exhibit A, Tab 1, p. 35, Union will consider a number of criteria in planning and prioritizing the additional 25 potential Projects. The criteria to be considered for each Project will include the estimated Project P.I., the number of potential customers, capital availability, expected project duration, and the capacity of the local Districts to undertake detailed costing and market surveys to finalize feasibility studies.

d) Contingent on coincidental reinforcement occurring as planned in 2017, capacity is expected to be available to meet Union's preliminary design. However, the Ripley/Lucknow Project would accelerate a need for future reinforcement of the upstream system, and this advancement has been factored into the preliminary economics of the Project.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: Exhibit A, Tab 1, Appendix D
Potential Energy Savings

Preamble: Please provide the following additional analysis for each of the five initial proposed Community Expansion projects identified at Exhibit A. Tab 1, p. 45, Table 8 and also for the Kincardine, Tiverton, Paisley, Chesley project which appears as number 29 in the list in Exhibit A, Tab 1, Appendix D, p. 1.

a) Any difference from the penetration rates by competing fuel source presented in the Exhibit A, Tab 1, Page 18, Table 1, with supporting information.
b) Given that each community has different composition with respect to the competing energy sources, the anticipated overall penetration rate for each community.
c) A sensitivity analysis that recalculates the information provided in the table at Exhibit A, Tab 1, Appendix D, assuming that the penetration rates for all competing energy sources are (i) 10 percentage point more and (ii) 10 percentage points less, than Union's base case assumption.
d) A sensitivity analysis that recalculates the information provided in the table at Exhibit A, Tab 1, Appendix D, assuming that the annual volumes are (i) 10 percent more and (ii) 10 percent less, than Union's base case assumption.
e) Please provide details of assumptions with respect to the commodity cost of natural gas and competing energy sources used in the potential annual savings in Appendix D and the Annual Residential Energy Savings Estimate at Ex. A, Tab 1, page 18, Table 1. Compare those assumptions with Union's current commodity cost projections and provide an updated version of Appendix D based on Union current projection of commodity costs for natural gas and competing energy sources.

Response:

a) Heating system penetration rates for Milverton, Prince Township, and Lambton Shores are shown in Table 1 below. Rates reported include survey responses from residential customers and a small number of properties used for both residential and commercial purposes. Due to the way the responses were coded during the survey interviews, it is not possible to provide a similar break-down of penetration rates by fuel source as that shown in Exhibit A, Tab 1, Table 1. The source of this information is provided at Exhibit B.Staff.11.

Union has not provided similar data for the Moraviantown Project, or for the Kettle and Stony Point First Nation component of the Kettle Point/Lambton Shores Projects. The reason for this is because a third party survey was not completed for those projects

Table 1: Penetration by Existing Heating System: Milverton, Prince Township, Lambton Shores

Heating System	Milverton	Prince Township	Lambton Shores	Kincardine Area[1]	Kincardine Ripley Area[2]
Oil Forced Air	33%	24%	5%	13%	13%
Electric forced air	7%	15%	10%	17%	17%
Electric baseboard	6%	25%	12%	23%	21%
Propane forced air	30%	14%	53%	21%	20%
Other heating system[3]	24%	21%	22%	26%	29%

Fuel source penetration rates for residential and commercial properties in Kincardine are shown in Table 2 below. The sources of this information are the 2011 Kincardine Residential Survey, provided at Attachment 1, and the 2011 Kincardine Commercial Survey, provided at Attachment 2.

Table 2: Penetration by Fuel Source: Kincardine Residential Comparison

Fuel Source	Exhibit A Tab 1 Table 1 Data	Residential		Commercial	
		Kincardine Area[1]	Kincardine Ripley Area[2]	Kincardine Area[1]	Kincardine Ripley Area[2]
Oil	35%	13%	13%	34%	36%
Wood	28%	11%	12%	1%	2%
Electric	22%	41%	39%	15%	16%
Propane	15%	24%	22%	41%	44%
Other fuel source[4]	0%	12%	14%	2%	2%

b) The likelihood to convert in the absence of a TES is shown in Table 3 for Milverton, Prince Township, Lambton Shores and the Kincardine area.

[1] Includes responses from Kincardine, Chesley, Tiverton, Paisley, Point Clark, and Holyrood.
[2] Includes responses from the Kincardine Project Area (Kincardine, Chesley, Tiverton, Paisley, Point Clark, and Holyrood), as well as Ripley and Lucknow. Due to the small base size, penetrations cannot be reported separately for Ripley and Lucknow.
[3] Other heating system includes: oil boiler, propane boiler, “something else”, or no heating system.
[4] Other fuel source includes geothermal, heat pump, or “something else.”

Anticipated conversion rates with consideration for both the conversion costs and the TES are provided for Milverton, Prince Township, Lambton Shores and Kincardine in the bottom row of Table 4. In the 2011 Kincardine survey, respondents were not asked to consider the TES. Therefore, to estimate the likelihood to convert with the TES, Union made assumptions based on the Milverton, Prince Township, and Lambton Shores survey results. Specifically, Union calculated the weighted average reduction in the likelihood to convert when respondents were asked to consider the TES, and applied this reduction to the Kincardine Survey results.

Sources underlying Tables 3 and 4 are the same sources noted in part a) above.

Table 3: Likelihood to Convert Heating Equipment Without TES

	Likelihood to Convert Heating System To Natural Gas (Base: all respondents)					
	Milverton	**Prince Township**	**Lambton Shores**	**Total 3 Projects**	**Kincardine Area[5] Residential**	**Kincardine Ripley Area[6] Residential**
Base	*(n=194)*	*(n=124)*	*(n=100)*	*(n=418)*	*(n=214)*	*(n=220)*
Top 3 (Extremely / Very / Likely)	84%	90%	86%	86%	70%	69%
Top 2 (Extremely / Very Likely)	59%	70%	69%	65%	50%	49%
Top 2 + 50% of Likely	71%	80%	78%	75%	60%	59%

Table 4: Likelihood to Convert Heating Equipment With TES

	Likelihood to Convert Heating System (Calibrated to (Population)				Estimated Likelihood: Kincardine/Ripley Areas
	Milverton	**Prince Township**	**Lambton Shores**	**Total**	
Base	*(n=194)*	*(n=124)*	*(n=100)*	*(n=418)*	*(n=366)*
Top 3 (Extremely / Very / Likely)	76%	81%	73%	74%	68%
Top 2 (Extremely / Very Likely)	46%	48%	58%	48%	44%
Top 2 + 50% of Likely	61%	65%	66%	**61%**	**56%**

The overall anticipated residential penetration rate can be found in the bottom row of Table 4. This estimate suggests that the 45% penetration rate Union used in its Opportunity Analysis, presented in Exhibit A, Tab 1, Appendix D, is extremely conservative. A more likely figure, even when using Union's conservative estimates (those who indicate "Extremely Likely",

[5] Includes responses from Kincardine, Chesley, Tiverton, Paisley, Point Clark, and Holyrood; used residential base only.
[6] Includes responses from the Kincardine Project Area (Kincardine, Chesley, Tiverton, Paisley, Point Clark, and Holyrood), as well as Ripley and Lucknow. Due to the small base size, penetrations cannot be reported separately for Ripley and Lucknow; used residential base only.

"Very Likely" and 50% of "Likely") is residential penetration in the 61% range based on the 3 surveys in which the TES was actually tested with potential customers.

Attachment 3 is a table that provides an alternative attachment scenario of 60%. This is an expanded version of the information provided in Exhibit A, Tab 1, Appendix D for projects that may be feasible without a need for Aid-to-Construction (CIAC). The number of projects that may become feasible with a penetration rate assumption set at 60% would increase by 4 projects, and the potential capital cost would increase to approximately $166 million.

Union is also aware of the desire of the South Bruce Municipalities to have the Kincardine area Project bundled together with the Ripley/Lucknow Project. Union has created a scenario based upon estimated penetration rates[7] of 50% residential and 65% commercial. This bundled project would service the communities of Kincardine, Tiverton, Paisley, Chesley, Ripley and Lucknow. The P.I. is estimated at 0.4 with a nine year term for the TES and ITE. A 10 year term for ITE and TES would result in a P.I. of 0.43. The capital cost for this project would be approximately $88 million. No additional CIAC or funding from the government is required to make this Project feasible under Union's filed proposal. This combined Project would enable approximately 9,200 homes and businesses to gain access to natural gas.

When combined with the increased estimate of forecasted customers for future projects as provide in Attachment 3, bundling the Kincardine and Ripley Projects together would increase the potential capital spend on future Community Expansion Projects from $150 million as filed to approximately $190 million. In this case the estimated annual bill impacts for an average Rate M1 residential customer consuming 2,200 m^3 annually would be approximately $6.35, or $4.26 when including the TES/ITE deferral credits.

c) Union made the assumption that a penetration rate of 10 percentage points more and 10 percentage points less is calculated on the potential customers and not the forecast customers. For example, for Milverton, the sensitivity will be based on 82 more and less attachments (10% x 818 potential customers).

i) Please see Attachment 4.
ii) Please see Attachment 5.

d) i) Please see Attachment 6.
ii) Please see Attachment 7.

[7] The discounted penetration rates specific to potential residential and commercial customers from the Kincardine area surveys, after applying the methodology noted to determine the impact of the TES. Weighted average for these is 56% as noted in Table 4.

e) Because the intent of Exhibit A, Tab 1, was only to inform the Board of the potential impact of a broader Community Expansion Program, the potential savings as noted at the bottom of p. 3 of Appendix D are based on a very simplified calculation of the number of potential customers, times average annual residential savings of $1,602 per customer.

This average residential savings figure of $1,602 corresponds with a calculation of the weighted average of the figures at the bottom of Table 1 in Exhibit A, Tab 1. The weighted average is determined by applying Union's general service customer distribution of approximately 75% in the southern rate area and 25% in the north and east rate areas.

Filed: 2015-12-14
EB-2015-0179
Exhibit B.South Bruce. 6
Attachment 1
Page 1 of 5
Corrected

Kincardine and Area Natural Gas Pipeline Expansion Study – Topline Report

Background

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario. Union Gas serves over 1.3 million residential, commercial and industrial customers in more than 400 communities across Northern, Southwestern and Eastern Ontario. However, the Municipality of Kincardine et al is the largest community in Southwestern Ontario that is not serviced by Union Gas.

At the request of the Municipality of Kincardine et al and local industries, Union Gas is reviewing the feasibility of constructing gas pipeline that will service the communities of Chesley, Paisley, Tiverton and Kincardine (Owen Sound Communities), the communities of Ripley and Lucknow (Hensall Communities) and 5 major industrial sites: Greenfield Ethanol, Bruce Power, Ontario Power Generation, Canadian Agra and Paisley Brick.

Research Objectives

The goal of this research is to ascertain the support for natural gas availability in the named communities and evaluate the opportunity of gas conversion for both residential and commercial units. Specifically, this research aims to:

- Measure the likelihood of converting heating equipment based on a range of average conversion costs
- Gauge interest in switching to natural gas water heater based on a range of average conversion costs
- Determine the blend of occupied and semi-occupied residential homes (i.e. cottage versus home)
- Measure the perception of natural gas in these communities

Methodology

Telephone interviews were conducted by Ipsos-Reid, a third party supplier, with 300 randomly selected homeowners in the target communities, yielding a margin of +/-5.5% at 95% confidence level. The fielding period for the residential survey was from August 22nd to 24th, 2011.

Highlights

- Overall, 66% of all respondents stated that they are likely to convert their home heating system and/or water heater to natural gas.
- 78% of those who are likely to convert would do so within first 2 years; 49% will do so in first 12 months.
- 67% of respondents indicated that they would likely convert their home heating system to natural gas. For home heating, 31% of Kincardine et al. citizens use oil forced or electric forced air, 25% use electric baseboard or boiler, and 20% use propane forced air.
- 58% of respondents indicated that they are likely to convert their water heater to natural gas. 81% of water heaters are powered by electricity, 10% is powered by propane.
- At least 60% of those who stated that they are likely to convert home heating system and/or water heater to natural gas are interested in converting their fireplace, clothes dryer, BBQ, or oven as well.
- Those who indicated that they are unlikely to convert to natural gas cited cost, moving or having recently installed heating system as major reasons.
- Respondents that are unlikely to convert to natural gas have significantly weaker perceptions of natural gas. Particularly, of those unlikely to convert, only 48% agree that natural gas is the energy of best value.
- Majority of households occupy their dwelling all year round.
- On average, houses in Kincardine and surrounding communities are about 41 years old and the citizens tend to be about 56 years old.

Findings

Home Heating

Residents of Kincardine and surrounding communities use diverse technologies for home heating. The most popular home heating systems used are electric baseboard, propane, electric forced, and oil forced air, respectively. About 24% of respondents use other systems of home heating such as wood (12%) and geothermal heating (4%). Overall, 67% of the respondents that are eligible to convert indicated that they would likely convert their home heating system to natural gas.

88% of electric baseboards are 11 years or older, 34% of the respondents that use electric baseboards stated that they are likely to replace their heating system in the next 2 years. Likelihood to convert is highest among propane users even though they have newer heating systems. About 68% of respondents who use oil or electric forced air are likely to convert to natural gas.

Table 1: Home Heating

	Oil Forced Air (n=39)	Electric Forced Air (n=53)	Propane (n=60)	Electric Baseboard (n=65)	Boiler (n=10)
Penetration	13%	18%	20%	22%	3%
Likely to replace in the next 2 years*	36%	28%	20%	34%	20%
Likely to convert to NG	69%	68%	83%	52%	50%
Overall likelihood to convert**	152/227 = 67%				
Age of home heating system					
5 years or less	23%	25%	52%	5%	30%
6 to 10 years	31%	13%	35%	6%	30%
11 to 15 years	13%	9%	7%	5%	10%
16+ years	33%	53%	7%	83%	30%

**Extremely/very/likely*

***Base; total eligible (n=227)*

Water Heating

For water heating, majority of Kincardine et al use electricity. 89% of all respondents own their water heaters. Respondents who use oil for water heating are less likely to own their water heaters. Most water heaters are aged 10 years or less. Overall, 58% of respondents that are eligible to convert their water heaters stated that they are likely to convert to natural gas.

Table 2: Water Heating

	Oil (n=20)	Electricity (n=242)	Propane (n=29)
Penetration	7%	81%	10%
Own water heater	65%	92%	83%
Likely to convert to NG*	62%	55%	71%

Filed: 2015-12-14
EB-2015-0179
Exhibit B.South Bruce. 6
Attachment 1
Page 3 of 5
Corrected

Likely to convert to NG**	86%	65%	80%
Overall likelihood to convert	170/291 = 58%		
Age of water heater			
5 years or less	30%	50%	72%
6 to 10 years	50%	28%	21%
11 to 15 years	15%	9%	7%
16+ years	5%	12%	0%

**Base: own water heater; n= 268*

***Base: rent n=32*

Other Appliances

Of those who stated that they are likely to convert their home heating system and/or water heater to natural gas, 72% showed interest in powering their BBQ with natural gas, 70% for fireplace, 61% for oven, range or stove, and 60% for clothes dryer.

Conversion time

Respondents that indicated likelihood to convert home heating system and/or water heater to natural gas were asked when they are likely to do so if natural gas is available after December 2012, 78% of them stated that they are likely to convert within 2 years. Of the entire survey respondents, 52% said they are likely to convert within 2 years.

Table 3: Conversion time

	Within first 12 months	Within 1 to 2 years	Within 2 to 3 years	After 3 years
Overall*	49%	29%	12%	10%
Calibrated to total population	33%	19%	8%	6%
Likely to convert home heating to NG	53%	28%	12%	8%
Likely to convert water heat to NG	51%	28%	12%	9%

**Base: likely to convert home heating system and/or water heater to NG (n=199)*

Natural Gas Perception

Overall, the citizens of Kincardine and surrounding communities have favorable perceptions of natural gas. At least 83% of the citizens agree that natural gas is a clean burning fuel, reliable energy source, and a safe energy source. However, a lower percentage (68%) agrees that natural gas provides the best energy value. Respondents aged 55 years or older are more likely to agree that natural gas is the best energy value.

Of the respondents that indicated that they would likely convert to natural gas later (after 3 years), only 58% of them agree that natural gas provides the best energy value.

Table 4: Natural Gas Perception

	Clean Burning Fuel	Reliable Energy Source	Safe Energy Source	Best Energy Value
Overall agree with statement*	89%	89%	83%	68%
Likely to convert to NG				
Home heating	95%	97%	92%	88%
Water heater	97%	97%	92%	83%
Unlikely to convert to NG				
Home heating	82%	72%	68%	48%
Water heater	79%	78%	69%	48%
Age of Respondents				
18-34	77%	77%	73%	64%
35-44	83%	86%	83%	62%
45-54	93%	91%	89%	63%
55+	91%	90%	81%	73%
Conversion time**				
Within first 12 months	96%	99%	94%	90%
Within 1 to 2 years	95%	95%	90%	81%
Within 2 to 3 years	100%	96%	91%	83%
After 3 years	90%	84%	79%	58%

**Strongly agree/agree, base: all respondents*
***of those that are likely to convert to NG*

Demographics

Majority of the survey respondents stated that they occupy their dwelling all year round. Of those that do not occupy their dwelling all year round, 77% resided in their residence for at least 6 months in 2010. The average age of houses in the target area is about 41 years old. The houses are on average approximately 1800 square feet large and are likely to be one or two story houses. Most households are occupied by 1 or 2 adults are not likely to have any children. Of those who reported their total household income in the past year, 17% earn an annual household income that is below $40,000, 33% have a household income between $40,000 and $80,000, and the remaining 49% earn $80,000 or more.

Table 5: Demographics

	Frequency
Occupancy	
All-year round	91%
Summer months	6%
Occasionally year round	2%
Style of house	
Bungalow/One story ranch	39%
Raised ranch	7%
Split level	14%

Filed: 2015-12-14
EB-2015-0179
Exhibit B.South Bruce. 6
Attachment 1
Page 5 of 5
Corrected

Two story	27%
Other	12%
Approximate size of home (in sq. feet)	
500 to 1000	6%
1001 to 1500	32%
1501 to 2500	42%
2501+	12%
Age of home	
0 to 15 years	21%
16 to 30 years	17%
31 to 45 years	33%
46 to 60 years	6%
61+ years	17%
Number of adults 18 years or older living in house	
1-2	84%
3+	16%
Number of children 17 years or younger living in house	
0	74%
1-2	19%
3+	6%
Total Household Income*	
Less than $40,000	17%
40,000 to $80,000	33%
More than $80,000	49%

*excluding "don't know"s

Kincardine Gas Pipeline Study – Commercial Survey Results

Background

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario. Union Gas serves over 1.3 million residential, commercial and industrial customers in more than 400 communities across Northern, Southwestern and Eastern Ontario. However, the Municipality of Kincardine et al is the largest community in Southwestern Ontario that is not serviced by Union Gas.

At the request of the Municipality of Kincardine et al and local industries, Union Gas is reviewing the feasibility of constructing gas pipeline that will service the communities of Chesley, Paisley, Tiverton and Kincardine (Owen Sound Communities), the communities of Ripley and Lucknow (Hensall Communities) and 5 major industrial sites: Greenfield Ethanol, Bruce Power, Ontario Power Generation, Canadian Agra and Paisley Brick.

Research Objectives

The goal of this research is to ascertain the support for natural gas availability in the named communities and evaluate the opportunity of gas conversion for both residential and commercial units. Specifically, this research aims to:

- Measure the likelihood of converting heating equipment based on a range of average conversion costs
- Gauge interest in switching to natural gas water heater based on a range of average conversion costs
- Determine the blend of occupied and semi-occupied residential homes (i.e. cottage versus home)
- Measure the perception of natural gas in these communities

Methodology

A total of 174 interviews were conducted by a third party supplier, Ipsos-Reid, with businesses in the target communities, yielding a 6.7% margin of error at 95% confidence level. The fielding period for the commercial survey was from August 23rd to September 9th, 2011.

Highlights

- Overall, 85% of all respondents stated that they are likely to convert their heating system and/or water heater to natural gas.
- 50% of the businesses in Kincardine et al use a forced air furnace for heating. 43% of forced air furnaces are powered by propane.
- 73% of all respondents indicated that they would likely convert their heating system to natural gas. 85% would do so within the first 2 years; 61% within first 12 months
- 60% of water heaters are powered by electricity; 25% is powered by propane.
- 74% of all respondents indicated that they would likely convert their water heater to natural gas. 87% stated they would likely convert within the first 2 years; 67% within first 12 months.
- 53% of all respondents stated that they have cooking equipment on-site, the cooking equipments are powered by electricity (71%) and propane (29%). 62% of businesses that have cooking equipment on site are likely to convert cooking equipment to natural gas.
- Respondents who stated that they are unlikely to convert cited cost and having recently installed a new heating equipment as major reasons.
- On average, the commercial buildings in Kincardine and surrounding communities are about 53 years old.

Findings

Heating System

Half of the businesses in the target area use forced air furnace for their heating systems. 9% of respondents stated that they have no heating equipment in their business. Oil and propane are the most common fuel used to power furnaces and boilers. 18%[1] of all respondents stated that they have more than one heating system used to heat their facility.

73% of all respondents indicated that they are likely to convert their heating system to natural gas. Majority of those who indicated likelihood to convert would do so within 12 months of natural gas availability.

[1]27% of those eligible to convert.

Table 1: Heating System

	Boiler (n=30)	Forced Air Furnace (n=87)	Other (n=42)
Penetration	17%	50%	24%
Fuel type			
Electric	7%	15%	29%
Oil	47%	33%	7%
Propane	40%	43%	14%
Other	7%	2%	43%
Age of Appliance			
Less than 5 years	10%	14%	n/a
5 – 10 years	33%	37%	n/a
11 – 15 years	23%	16%	n/a
16 – 20 years	13%	16%	n/a
More than 20 years	7%	9%	n/a
Likely to convert	87%	78%	74%
Overall likelihood to convert[2]	73%		
Overall likelihood to convert (eligible)[3]	80%		
Conversion Timeline[1]			
Within first 12 months	54%	63%	61%
Within 1 – 2 years	31%	22%	26%
Within 2 – 3 years	4%	3%	10%
Beyond 3 years	4%	6%	3%

[1]base: likely to convert
[2]Calibrated over all respondents; n= 174
[3]base = have heating equipment/DK; n= 159

Water Heater

60% of water heaters used in businesses within the target area are electric, 25% are propane. Overall, 74% of respondents are likely to convert their water heater to natural gas; majority indicated that they would do so within the first 12 months.

Table 2: Water Heating

	Electricity (n=104)	Propane (n=43)	Other (n=17)
Penetration	60%	25%	10%
Likely to convert	73%	93%	53%
Overall likelihood to convert	74%		
Conversion Timeline			
Within first 12 months	63%	78%	56%
Within 1 – 2 years	22%	15%	22%
Within 2 – 3 years	4%	3%	0%
Beyond 3 years	5%	0%	11%

Other Energy-using Processes

53% of businesses in the target communities stated that they have cooking equipment(s) on-site. The cooking equipments are either powered by electricity (71%) or by propane (29%). 62% of businesses that have a cooking equipment stated that they are likely to convert to natural gas and majority (73%) would do so within the first 12 months.

10% of all the businesses interviewed indicated either industrial, grain, greenhouse, poultry or swine as their main line of business. When asked about other energy-using processes that happen on-site, 29% stated that “washing” occurs and 6% stated that “burning” occurs. The other energy-using processes indicated are “drying”, “curing” and “melting” (12% each). The business with the “burning” process indicated likelihood to convert process to natural gas. About half of the businesses with “drying”, “washing” and “melting” indicated that they are likely to convert process to natural gas. The businesses with “curing” process indicated that they are not likely to convert their process to natural gas.

Characteristics

Majority of the respondents operate their businesses all year round; 7% in summer months only. 33% of the commercial buildings in the target area are 10,000 square feet or more.

All the businesses interviewed that indicated food services as their main line of business stated that they are likely to convert their heating system and water heater to natural gas. Businesses with entertainment as their main line of business (pools etc) are more likely to convert their water heater than heating system.

Table 3: Characteristics of businesses

	Frequency	Likely to convert Heating System	Likely to convert Water Heater
Business Type			
Agriculture	12%	70%	80%
Industrial	8%	71%	57%
Service	26%	80%	73%
Retail	9%	67%	73%
Entertainment	7%	58%	92%
Food Service	6%	100%	100%
Other	32%	70%	63%
Size of Building (in sq. feet)			
2,999 or less	27%	72%	70%
3,000 to 9,999	23%	84%	80%
10,000 to 49,999	25%	82%	71%
50,000 or more	8%	92%	50%
Operation			
All year round	93%	81%	75%
In summer months	7%	75%	75%

Opportunity Assessment Summary

				Including TES/ITE Min PI= 0.4 - As Filed				
Row	**Community Name**	**Communities**	**Potential Customers**	**Forecast Customers**	**Gross Capital Cost (milllions)**	**Natural PI***	**TES/ITE Months**	**CIAC Required (millions)**
1	Milverton	1	818	526	$4.77	0.32	48	
2	Prince Township, Sault Ste Marie	1	375	242	$2.72	0.38	48	
3	Lambton Shores, Kettle Point First Nation	2	496	281	$1.79	0.42	48	
4	~~Walpole Island First Nation- main commercial area~~	Removed from application						
5	Moraviantown First Nation- main commercial area	1	70	61	$0.49	0.35	48	
	TOTAL - Projects #1 to 5	**5**	**1,759**	**1,110**	**$9.8**			

				Including TES/ITE Min PI= 0.4 - At 45% Penetration Rate					**Including TES/ITE Min PI= 0.4 - At 60% Penetration Rate**				
				Forecast Customers	**Gross Capital Cost (milllions)**	**Natural PI***	**TES/ITE Months**	**CIAC Required (millions)**	**Forecast Customers**	**Gross Capital Cost (milllions)**	**Natural PI***	**TES/ITE Months**	**CIAC Required (millions)**
6	Lagoon City (Orillia)	1	2,556	1,150	$14.19	0.42	48		1,534	$16.17	0.49	48	
7	Hidden Valley/Huntsville	1	100	46	$0.65	0.38	48		60	$0.72	0.44	48	
8	Santa's Village/Beaumont Dr, Bracebridge	1	133	60	$0.86	0.36	48		80	$0.96	0.43	48	
9	Canal, Gravenhurst	1	166	74	$1.17	0.33	48		100	$1.31	0.39	48	
10	Northshore Rd / Peninsula Rd North Bay	1	333	150	$2.34	0.33	48		200	$2.60	0.40	48	
11	**Hornby	1	115	64	$1.22	0.16	77		69	$1.23	0.17	72	
12	Oneida First Nation	1	466	210	$2.20	0.28	48		280	$2.33	0.35	48	
13	Auburn	1	108	49	$0.53	0.27	48		66	$0.56	0.34	48	
14	Cedar Springs	1	175	79	$0.90	0.25	48		105	$0.94	0.32	48	
15	Astorville	1	467	210	$3.71	0.29	49		280	$4.07	0.35	48	
16	~~***Brenman Line, Servern Twp (Gravenhurst)~~												
17	Nipissing First Nation / Jocko Point	1	467	210	$3.92	0.28	60		280	$4.27	0.34	48	
18	~~***Munsee Delaware First Nation~~												
19	Chippewa of the Thames First Nation- phase 3 & 4	1	110	50	$0.72	0.21	64		66	$0.75	0.26	48	
20	Sheffield	1	120	54	$0.78	0.20	70		72	$0.81	0.26	48	
21	Turkey Point	1	541	244	$3.65	0.20	83		325	$3.83	0.25	55	
22	Rockton	1	125	57	$0.88	0.19	79		75	$0.91	0.24	50	
23	Chippewas of the Saugeen	1	120	54	$0.87	0.19	83		72	$0.91	0.24	55	
24	Washago	1	405	182	$4.14	0.23	88		243	$4.46	0.28	59	
25	E Floral (T Bay area)	1	100	46	$1.08	0.21	84		60	$1.14	0.26	60	
26	Haldimand Shores	1	150	68	$1.80	0.20	105		90	$1.89	0.24	84	
27	Latchford, Tri Town	1	200	90	$2.34	0.20	111		120	$2.49	0.25	74	
28	Belwood	1	768	346	$5.79	0.18	95		461	$6.04	0.23	64	
29	**** Kincardine. Tiverton, Paisley, Chesley	4	8,331	4,250	$66.25	0.23	84		5,000	$67.32	0.26	64	
30	~~***Little Longlac~~												
31	Swiss Meadow	1	108	49	$1.02	0.15	111		65	$1.05	0.19	80	
32	Boblo Island	1	300	136	$2.66	0.15	117		180	$2.71	0.19	85	

Opportunity Assessment Summary

				Including TES/ITE Min PI= 0.4 - As Filed									
Row	**Community Name**	**Communities**	**Potential Customers**	**Forecast Customers**	**Gross Capital Cost (milllions)**	**Natural PI***	**TES/ITE Months**	**CIAC Required (millions)**					
33	Village of Warwick	1	150	69	$1.48	0.14	120		90	$1.52	0.18	97	
34	~~Mohawks of the Bay of Quinte (Tyendinaga FN)~~			Completed in 2015									
35	Garden Village (Promenade-de-lac)	1	133	60	$1.80	0.18	120	$0.11	80	$1.91	0.22	89	
36	Sioux Narrows / Nester Falls	2	1,044	470	$14.11	0.17	120	$1.84	626	$14.67	0.21	97	
37	Wroxieter/Gorrie/Fordwich	3	810	364	$8.06	0.14	120	$0.93	486	$8.32	0.18	97	
38	**Total Projects # 1 to 5**	**5**	**1,759**	**1,110**	**$9.8**				**1,110**	**$9.8**			
39	**Total- Projects #6 to 33 (Min PI 0.4 no aid)**	**28**	**16,614**	**7,997**	**$125.2**				**9,973**	**$131.0**			
40	**Total: Projects #34 to 37 (Min PI 0.4 no aid)**								**1,192**	**$24.9**			
41	**TOTAL - All Projects**	**33**	**18,373**	**9,107**	**$134.9**				**12,275**	**$165.7**			

* Project profitabilty index based on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.
** Hornby was filed using a 56% penetration rate
*** Project does not meet definition of Community Expansion Project so would not be eligible for reduced PI without additional project scope.
**** Kincardine. Tiverton, Paisley, Chesley has a 51% penetration rate in 45% attachment rate columns
Note: Capital cost difference between 45% and 60% scenarios is the additional customer connection costs

Opportunity Assessment Summary - Increase of 10% in Penetration Rate

											Including TES/ITE					
											Min PI= 0.4		Min PI= 0.5		Min PI=0.6	
Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (milllions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)
1	Milverton	1	818	608	21	2.36	$4.88	$5,968	0.36	$1.31	48		48		48	
2	Prince Township, Sault Ste Marie	1	375	280		0.68	$2.81	$7,495	0.43	$0.60	48		48		73	
3	Lambton Shores, Kettle Point First Nation	2	496	331	6	0.88	$1.87	$3,779	0.50	$0.79	48		48		48	
4	Walpole Island First Nation- main commercial area	Removed from application														
5	Moraviantown First Nation- main commercial area	1	70	68	5	0.15	$0.50	$7,104	0.38	$0.11	48		48		48	
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	5,078	87	15.62	$67.58	$8,111	0.26	$15.12	63		98		120	$6.42
	TOTALS- All Projects	9	10,090	6,365			$77.64	$7,695		$17.94						$6.42
5	Qualifying Projects with no CIAC at PI= 0.4;	9	10,090	6,365			$77.64			$17.94						
5	Qualifying Projects with no CIAC at PI= 0.5;	9	10,090	6,365			$77.64			$17.94						
4	Qualifying Projects with no CIAC at PI= 0.6;	5	1,759	1,287			$10.06			$2.82						

* Project profitabilty index basd on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.
** Simplified calulation assuming residential NAC for all customers and no contract customer volumes

Opportunity Assessment Summary - Decrease of 10% in Penetration Rate

											Including TES/ITE					
											Min PI= 0.4		Min PI= 0.5		Min PI=0.6	
Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (milllions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)	TES/ITE Months	CIAC Required (millions)
1	Milverton	1	818	444	21	1.97	$4.65	$5,686	0.28	$1.31	48		48		61	
2	Prince Township, Sault Ste Marie	1	375	205		0.51	$2.62	$6,998	0.33	$0.60	48		70		106	
3	Lambton Shores, Kettle Point First Nation	2	496	231	6	0.64	$1.71	$3,451	0.38	$0.79	48		48		48	
4	Walpole Island First Nation- main commercial area	Removed from application														
5	Moraviantown First Nation- main commercial area	1	70	54	5	0.12	$0.48	$6,917	0.31	$0.11	48		48		63	
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	3,419	87	11.00	$64.92	$7,793	0.20	$15.12	109		120	$14.21	120	$25.15
	TOTALS- All Projects	9	10,090	4,353			$74.40	$7,373		$17.94				$14.21		$25.15
5	Qualifying Projects with no CIAC at PI= 0.4;	9	10,090	4,353			$74.40			$17.94						
4	Qualifying Projects with no CIAC at PI= 0.5;	5	1,759	934			$9.47			$2.82						
4	Qualifying Projects with no CIAC at PI= 0.6;	5	1,759	934			$9.47			$2.82						

* Project profitabilty index basd on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.
** Simplified calulation assuming residential NAC for all customers and no contract customer volumes

Opportunity Assessment Summary - Increase of 10% in Volumes

Row	Community Name	Communities	Potential Customers	Forecast Customers	Distance From Source (km)	Annual Volume (million m3)	Gross Capital Cost (milllions)	Gross Capital/ Potential Customer	Natural PI*	Potential Annual Savings** (millions)	Including TES/ITE — Min PI= 0.4: TES/ITE Months	Min PI= 0.4: CIAC Required (millions)	Min PI= 0.5: TES/ITE Months	Min PI= 0.5: CIAC Required (millions)	Min PI=0.6: TES/ITE Months	Min PI=0.6: CIAC Required (millions)
1	Milverton	1	818	526	21	2.38	$4.77	$5,827	0.34	$1.31	48		48		48	
2	Prince Township, Sault Ste Marie	1	375	242		0.65	$2.72	$7,243	0.40	$0.60	48		48		71	
3	Lambton Shores, Kettle Point First Nation	2	496	281	6	0.84	$1.79	$3,615	0.45	$0.79	48		48		48	
4	Walpole Island First Nation- main commercial area	Removed from application														
5	Moraviantown First Nation- main commercial area	1	70	61	5	0.15	$0.49	$7,011	0.36	$0.11	48		48		48	
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	4,250	87	14.64	$66.25	$7,952	0.23	$15.12	75		111		120	$11.76
	TOTALS- All Projects	9	10,090	5,360			$76.02	$7,534	1.78	$17.94						$11.76
5	Qualifying Projects with no CIAC at PI= 0.4;	9	10,090	5,360			$76.02		1.78	$17.94						
5	Qualifying Projects with no CIAC at PI= 0.5;	9	10,090	5,360			$76.02		1.78	$17.94						
4	Qualifying Projects with no CIAC at PI= 0.6;	5	1,759	1,110			$9.77		1.55	$2.82						

* Project profitabilty index basd on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.
** Simplified calulation assuming residential NAC for all customers and no contract customer volumes

Opportunity Assessment Summary - Decrease of 10% in Volumes

											Including TES/ITE					
											Min PI= 0.4		Min PI= 0.5		Min PI=0.6	
Row	**Community Name**	**Communities**	**Potential Customers**	**Forecast Customers**	**Distance From Source (km)**	**Annual Volume (million m3)**	**Gross Capital Cost (milllions)**	**Gross Capital/ Potential Customer**	**Natural PI***	**Potential Annual Savings** (millions)**	**TES/ITE Months**	**CIAC Required (millions)**	**TES/ITE Months**	**CIAC Required (millions)**	**TES/ITE Months**	**CIAC Required (millions)**
1	Milverton	1	818	526	21	1.95	$4.77	$5,827	0.32	$1.31	48		48		59	
2	Prince Township, Sault Ste Marie	1	375	242		0.53	$2.72	$7,243	0.36	$0.60	48		60		96	
3	Lambton Shores, Kettle Point First Nation	2	496	281	6	0.69	$1.79	$3,615	0.43	$0.79	48		48		48	
4	Walpole Island First Nation- main commercial area	Removed from application														
5	Moraviantown First Nation- main commercial area	1	70	61	5	0.12	$0.49	$7,011	0.34	$0.11	48		48		60	
29	Kincardine. Tiverton, Paisley, Chesley	4	8,331	4,250	87	11.98	$66.25	$7,952	0.22	$15.12	94		120	$7.13	120	$19.75
	TOTALS- All Projects	9	10,090	5,360			$76.02	$7,534	1.68	$17.94				$7.13		$19.75
2	Qualifying Projects with no CIAC at PI= 0.4;	9	10,090	5,360			$76.02		1.68	$17.94						
2	Qualifying Projects with no CIAC at PI= 0.5;	5	1,759	1,110			$9.77		1.46	$2.82						
4	Qualifying Projects with no CIAC at PI= 0.6;	5	1,759	1,110			$9.77		1.46	$2.82						

* Project profitabilty index basd on customer forecast and distribution revenue, excluding TES and ITE contributions proposed in this filing.
** Simplified calulation assuming residential NAC for all customers and no contract customer volumes

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: System Benefits of Union's Community Expansion Project Proposal

Please identify with supporting explanation all indirect system benefits that will flow to (i) Union's other customers, (ii) Union's shareholders, (iii) the communities that receive gas service and (iv) the Province in general. For example, at what point in time will the annual revenue from these projects exceed the annual cost (revenue requirement), and what local and regional economic and environmental benefits should be expected? Are there system benefits in terms of upgraded infrastructure, service enhancements etc. Please provide any quantification of these benefits that is available to Union.

Response:

Please see the response at Exhibit B.CCC.5 for broad benefits and Exhibit B.SouthBruce.3 Attachment 1 for the years in which the revenues exceed the costs for the four proposed projects.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: System Benefits of Union's Community Expansion Project Proposal

If Provincial government funding were to be available to support these please identify the impact if any on:

a) The amount and/or duration of the TES

b) The duration of the ITE

c) The minimum PI used for the projects in calculating the required contribution

---

Response:

As noted in the response at Exhibit B.CCC.16, Union's understanding is the expectation is that Community Expansion Projects would need to exhaust any available regulatory flexibility before they would become eligible for provincial funding.

For this reason, Union has assumed that provincial funding would become available only to Projects that are not made feasible by Union's proposal, in which case the application of TES and ITE would be unaffected. To the extent that provincial funding becomes available independently of Union's Application, the duration of TES and ITE could be shortened, but Union's proposed minimum Project P.I. of 0.4 and the TES rate would still be applicable.

For further clarification, with approval of Union's proposal:

- If no Aid-to-Construction (CIAC) is required, any Provincial government funding provided towards a Project would serve to reduce the term of both the TES and ITE by the same period.
- If CIAC is required, any Provincial government funding would first serve to reduce the CIAC required. Any amount received beyond the required that CIAC amount would serve to reduce the term of both the TES and ITE by the same period.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: System Benefits of Union's Community Expansion Project Proposal

Please confirm that the total value of the contributions provided through the combination of the TES, the ITE and from other Union customers through the reduced PI in present value terms equals the CIAC that would be required in the absence of these proposals. If not, please explain the differences.

Response:

Not confirmed.

Except for the impact of income taxes the net present value ("NPV") of the amounts provided through the combination of the TES, ITE and rate impacts is equal to the NPV of the Aid-to-Construct.

Paraphrased, the question asks if the NPV after collection of TES and ITE is equal to the Aid-to-Construction ("CIAC") that would be required if the P.I. was 1.0. A P.I. of 1.0 indicates other customer rates are not negatively impacted over the longer term. A P.I. of 1.0 occurs when the NPV of the inflows is equal to the outflows and the NPV result then becomes zero.

When a CIAC is collected it reduces the capital investment eligible for the CCA tax deduction which in turn reduces the CCA tax shield (a cash inflow) that is assumed in the calculation of the NPV.

A CIAC which is grossed up for the CCA tax shield (which is lost when a CIAC is paid) would be required to solve for the NPV of zero.

An example as follows:

NPV Inflow	800
NPV Outflow (Capex)	1000

P.I. = 800/1000 = 0.8
NPV = 800-1000 = (200)

The implied assumption of the question assumes $200 CIAC would satisfy a P.I. of 1.0 (NPV of zero) such that existing customers are not impacted.

In the above example, a CIAC would reduce the outflow by $200 but would in turn reduce the $800 inflow by the CCA tax shield of the $200 that is not eligible for the tax deduction. As an approximation, a gross up of CIAC by about 15% to $230 would be needed.

UNION GAS LIMITED

Answer to Interrogatory from
Southern Bruce

Reference: System Benefits of Union's Community Expansion Project Proposal

Please comment on whether Union would agree with the view that the reduced PI is analogous to the Rural Rate Assistance mechanism that is used to provide a subsidy for service to electricity customers in high cost regions of the Province. Include in the comments, Union's views on the appropriateness of adopting a policy that ensures equal treatment, in terms of the subsidy from other customers that is provided, in all high cost areas, regardless of the distributor providing service.

Response:

Union's proposal is not like the Rural or Remote Electricity Rate Protection ("RRRP") mechanism. The RRRP mechanism is a statutory device that enables the cost of rural and remote connections to be socialized across all electrical customers in Ontario. As noted in the response at Exhibit B.Staff.2, cross subsidization between the customers of different distributors does not result in just and reasonable rates. RRRP enables, by way of legislative means, for such subsidization.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, p. 13, Appendix D

a) Please provide the criteria used to include potential communities in the Opportunity Assessment list.

b) Does the list of 103 candidates shown in Appendix D represent all the communities in Ontario without natural gas service?

Response:

a) Please see the response at Exhibit B.SEC.15.

b) No. Please see the response at Exhibit B.SEC.15. In addition, there may be other communities that Union has not identified based on the approach identified in Exhibit B.SEC.15. For example, since filing the Application, Union has received interest from Mallorytown, Holstein/Ayton, and Minden Hills. Union is also aware that other communities that appear to be closer to another gas LDCs system have expressed interest to those LDCs.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, Appendix D

a) Please explain why Sioux Lookout and Terrace Bay were excluded from the Community Expansion projects.

b) Please provide a map which shows Union Gas service for communities along the TransCanada Highway (17) between Thunder Bay and Sault Ste. Marie.

c) Has Union considered extending service to communities along Highway 17? Please explain what impediments there are to extending service in this area.

Response:

a) Sioux Lookout and Terrace Bay are in included in Exhibit A, Tab 1, Appendix D at lines 82 and 69. If Union's proposal is approved by the Board and funding is in place, these two communities could receive natural gas service.

b) Union does not have any pipelines along the TransCanada Highway (17) between Nipigon and Sault Ste. Marie. Union does serve communities between Thunder Bay and Nipigon.

c) Union has considered service to the communities of Terrace Bay and Marathon in the past. The costs to serve these communities were uneconomical.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, Appendix H

a) In 2012 Union proposed natural gas service to the Municipalities of Chelsey, Paisley, Tiverton, Kincardine, Point Clarke and Inverhuron. The first 4 of these communities are listed in Opportunity Assessment (line 29). Why does the Community Expansion program not include any of these communities in the first tranche of projects?

b) When does Union Gas expect to propose service to these communities?

Response:

a-b) In 2012, Union shared the results of a feasibility study with municipal leaders of the communities noted above. Union has never made a proposal for Leave-to-Construct for these areas because the feasibility analysis concluded that a project to service them would not meet E.B.O. 188 criteria and the Aid-to-Construction necessary to make the project economic was not available. Please see the response at Exhibit B.Staff.8 a) and Exhibit B.South Bruce.6.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, p. 17, Appendix E

a) How does actual attachment rate affect the calculation of the Temporary Expansion Surcharge?

b) Please explain why the TES is not accounted for as a contribution in-aid of construction.

Response:

a) The proposed TES rate is not impacted by the attachment rate. The TES will remain fixed at $0.23/m^3 over a fixed term on a community by community basis.

   The forecasted attachment rate is a key factor in determining the length of the fixed term required in order to achieve the specified P.I. level. To the extent that the actual attachment rate is higher/lower than forecast, more/less surcharge will be collected and disposed to all ratepayers through the Community Expansion Contribution Deferral Account as noted in Exhibit A, Tab 1, p. 33.

b) Please see the response at Exhibit B.LPMA.1 b).

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 3

a) Please provide the eligibility criteria for the Temporary Connection Surcharge.

b) Please explain how the collection period is determined for any specific project.

c) Please explain what economic feasibility study are completed for services eligible for the TCS. How are the costs of these studies recouped?

d) Please explain why the TCS amounts are not accounted for as contribution in aid of construction.

Response:

a) The eligibility criteria are provided in lines 1 to 7 at Exhibit A, Tab 3, p. 2. The TCS is not intended for use in Community Expansion Projects, because the proposed TES can be applied in those cases.

b) The collection period for the TCS will be based on the length of time required to make the main extension or commercial service attachment project economically feasible, subject to its proposed maximum term of 10 years.

c) Economic feasibility studies are completed in accordance with E.B.O. 188 guidelines. The studies consist of a discounted cash flow analysis of the projected revenues and the projected costs of each project, and they are completed for every main extension project or commercial/industrial customer addition project that Union connects. The cost to complete these studies is managed within the price cap of Union's IRM framework.

d) Please see the response at Exhibit B.LMPA.1 b). The explanation provided applies to the TCS as well as TES.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1

a) Please explain what (if any) incremental changes need to be made to Union's CIS/Billing systems in order to accommodate the TES/TCS surcharges. Please provide the estimated cost of these changes.

Response:

Union will be required to add a new rate in its existing rates tables within the billing system for both the TES and the TCS, and changes to the bill print functionality to enable the extra line items to be printed on applicable bills. Expected costs to make these changes are $0.1 million, which will be managed within Union's Incentive Regulation framework.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, p. 22

a) Please explain what (if any) impediments currently exist for letting municipalities making a contribution-in-aid of construction.

b) Has Union discussed the Incremental Tax Equivalent contribution with any of the municipalities it is proposing to provide service in within the next 5 years? If yes, please provide a summary of those discussions. If no please explain why not.

Response:

a) The primary impediment that municipalities have shared with Union is their ability to afford CIAC. These are generally smaller municipalities which have a limited tax base and limited capacity for additional debt.

b) Please see the response at Exhibit B.CCC.10.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1

a) Under Union's proposal are the all the revenues collected under the TES, TCS and ITE to be subject to earning sharing?

b) If yes please explain the rationale for this treatment.

c) Please provide the annual amount for each of these contribution methods for each of the next 5 years.

Response:

a-b) Yes. The revenues and costs related to Community Expansion are included in utility earnings subject to sharing. All the costs are included in utility earnings.

c) The TES and ITE for each of the five Projects Union is proposing is shown in the Cash Inflow section of the DCF found in each section of Exhibit A, Tab 2[1]. These are also summarized in the response at Exhibit B. Energy Probe.22.

Union does not have a forecast for the TCS as this would only apply to short line extensions which are typically in response to individual customer requests.

[1] The Walpole Island First Nations Project is proceeding with the support of Federal funding, under EBO 188 guidelines, at a P.I. of 0.8. It no longer requires Union's Community Expansion proposals to make it economically feasible.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, p. 40

Pre-amble: The Allocation methodology chosen by Union results in different amounts of costs allocated to Union North and Union South customers and a small decrease in costs to ex-franchise customers. Union has used the Board approved costs allocation study (updated) to achieve these results.

a) In light of the fact that Union is seeking exemptions from the E.B.O. 188 guidelines please explain the rationale for applying the existing cost allocation methodology for the costs of the Community Expansion projects. Please explain the principles that support this as a fair and reasonable allocation of the subsidy required for the projects.

b) Specifically address why it was not considered more appropriate to collect the subsidy equally from among all customers (by number and/ or volume).

c) Please explain the underlying principal or rationale for ex-franchise customers to see a reduction in costs as part of the Community Expansion projects.

Response:

a) Union's use of the current Board-approved cost allocation methodologies is consistent with Union's allocation of existing distribution-related costs and is consistent with the set of principles Union proposed as part of this application (per Exhibit A, Tab 1, Updated, p. 6). The use of existing cost allocation methodologies recognizes the incremental costs to provide distribution service to the potential Community Expansion Project communities and provides an indication of cost responsibility by rate class.

   The allocation of distribution rate base and O&M costs to Union North and Union South in-franchise rate classes is based on the underlying project costs to serve Union North and Union South. Of the total average capital investment in 2018 of $131.1 million (per Exhibit A, Tab 1, Appendix J, Updated), approximately $99.5 million (or 76%) is related to providing service to Union South expansion communities and $31.6 million (or 24%) is related to providing service to Union North expansion communities.

   Union's Board-approved cost allocation methodologies for distribution rate base and depreciation expense, distribution O&M costs, property taxes and income taxes is described at Exhibit B.LPMA.21.

To mitigate the cross subsidy from existing customers associated with the Projects, Union has proposed to introduce the Temporary Expansion Surcharge ("TES") and Incremental Tax Equivalent ("ITE"). These mechanisms provide a means for the customers and municipalities who directly benefit from the expansion to contribute to the financial viability of the project.

Accordingly, Union's Board-approved cost allocation is an appropriate method to allocate the Project costs to rate classes and is consistent with the Project principles. Union has proposed to mitigate the cross subsidy through the introduction of the TES and ITE and recognizes that a moderate cross subsidy from existing customers is acceptable, provided the long term rate impacts are reasonable (per Exhibit A, Tab 1, Updated, p. 6).

b) As described in a) above, the use of Union's existing cost allocation methodologies provides a reasonable indication of cost responsibility by rate class. Union's methodologies have been tested by intervenors and approved by the Board (per EB-2011-0210 Decision) as an appropriate allocation of costs.

The use of an alternate methodology to allocate the cross subsidy equally from all customers would result in an allocation of costs to rate classes in a manner that is inconsistent with the costs incurred to serve each rate class and cost causation principles.

Further, Union could incur additional challenges in identifying, recording and maintaining the amount of the cross subsidy over time, which would add to the complexity of Union's cost allocation study, rate design process and could result in additional changes to the billing systems which Union has not previously considered.

Accordingly, Union's use of the Board's previously approved cost allocation methodologies to allocate the Community Expansion Project costs is reasonable and appropriate.

c) Ex-franchise customers see a reduction in costs due to a re-allocation of indirect costs (general plant, administrative and general expenses, and general operations and engineering costs) in Union's 2013 Board-approved cost allocation study (updated per EB-2013-0365) from storage and transmission functional classifications to distribution functional classifications.

Specifically, by adding the rate base and operating costs associated with the Community Expansion Projects as distribution costs to the 2013 Board-approved cost allocation study, the cost components that are functionalized based on rate base and O&M are re-allocated from storage and transmission-related functional classifications to the distribution functional classification.

The re-allocation of indirect costs is consistent with the Board-approved cost allocation methodologies used in Union's capital pass through project applications, including Union's Parkway West and Brantford-Kirkwall/Parkway D Compressor Projects (EB-2012-0433/EB-

2013-0074), 2016 Dawn Parkway Expansion Project (EB-2014-0261), and 2017 Dawn Parkway Project (EB-2015-0200).

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, p. 42

a) As noted by Union the specifics as to the government announced loan and grant support have yet to be provided. Union notes that this introduces some uncertainty as to the objectives of the government policy. Given these factors why would it not be prudent to wait for the details as to how the Natural Gas Access Loans and the Economic Development grants before proceeding with any specific projects.

b) How would Union propose to treat any grants provided as part of the Community Expansion program?

Response:

a) Please see the response at Exhibit B.Energy Probe.3 c) and Exhibit B.CCC.16.

b) Please see the response at Exhibit B.LPMA.12 c).

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, pp. 1-2, Appendix D & H

a) The footnote to Appendix D notes projects which do not "*meet the definition of Community Expansion Project so would not be eligible for reduce PI without additional project scope*." Is the definition referred to that provided at page 1 of Appendix H?

b) Is the definition Union's construct or taken from government or Board policy? If the latter please provide the reference. If it is Union's definition please explain why a minimum of 50 customers was chosen.

c) Under this definition how do any customers become eligible for the TCS?

d) Does a definition of a Community Expansion project include a minimum or maximum PI?

Response:

a) Yes, Exhibit A, Tab 1, Appendix H, p. 1, lines 15-18.

b) The definition is of Union's construct. Union's proposal demonstrates a balanced approach to allow for expansion which provides access to the greatest possible number of communities while ensuring rate impact for existing customers is reasonable. Increasing the proposed minimum community size would unnecessarily limit the scope of the program and its impact on rural and northern communities. Decreasing the proposed minimum community size would result in unmanageable annual cost impacts for existing ratepayers.

Union's proposal is intentionally focused on small towns, villages and hamlets, because the higher density of customers as compared to more rural settings is likely to support stronger economic feasibility for the projects. Setting the threshold at 50 homes and businesses is a judgment call. Union recognized that the lower this threshold was set, the more projects would become candidates, and result in higher capital cost per attachment and resulting rate impact for existing ratepayers. The lower limit of 50 ensures Union can manage rate impacts for existing customers within the parameters described in evidence (maximum of $24/year).

The impact of changing the minimum project scope on the number of feasible projects at a minimum P.I. of 0.4 is provided below:

Minimum Size (Potential Customers)	Projects	Communities	Potential Customers	Gross Capital ($million)
50	30	34	19,805	$150
100	28	32	19,652	$149
250	13	17	17,672	$132
500	5	8	14,363	$106

Changing the threshold to 100 would not materially affect the amount of capital, or the number of Projects (28) Union anticipates, but it would eliminate several First Nations projects. Increasing the minimum to 250 or 500 would dramatically reduce the number of potential qualifying projects and would distort the balance Union has struck in setting the parameters for its proposal.

Union's small main extension proposal in Exhibit A, Tab 3 will provide a means of partially addressing challenges for smaller communities that are reasonably close to the existing system.

c) Under this definition no customers in Community Expansion Project areas will be eligible for the TCS. They will instead be eligible for the TES. Please refer to the response at Exhibit B.EnergyProbe.16 a) for further details.

d) The definition does not specifically include a minimum or maximum P.I. however, given that Union's proposal would permit moving forward with Community Expansion Projects at a minimum P.I. of 0.4, this level would be the minimum. If, in contrast, a Project could be completed at a P.I. above 1.0 without a need for TES or ITE, it would be excluded from Union's Community Expansion proposal in Exhibit A, Tab 1.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, Appendix F

a) Please explain how the incremental OM&A expenses were estimated for the proposed projects.

Response:

The estimated O&M is Union's standard O&M per new attachment which is applied for all attachments.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 2, Sections A-E

a) For the five projects included in this application please create a table which shows the unit costs of:

(1)Pipe per meter (NPS 2,4,6 ST & PE);
(2)Construction and Labour for laying of the pipeline by type of pipe
(3)Please explain any variation in unit cost and station costs as between the different projects.

b) Please provide the Environmental Assessment & Archeological Cost separately for each project.

c) Please explain the derivation of overheads for each project.

d) Please explain the derivation of Company Labour, X-Ray, Construction Survey, Legal, Mill Inspection and Consultants. Please also explain why some projects have this costs and other do not.

e) Please explain the variation in contingency costs (5%, 10% dollar amounts) as between the projects?

Response:

a-b) Please see Attachment 1.

c-e) Variations in the costs between projects can be attributed to differences in operating pressures, running lines, geography of construction, and environmental surroundings. All projects have an estimated overhead components as well as costs attributed to Company Labour, X-Ray, Construction Survey, Legal, Mill Inspection and Consultants. These costs will also vary depending on pipe material, size, construction considerations and environmental surroundings.

Project	Cost Per Metre of Pipe - Steel			Cost Per Meter of Pipe - PE				Construction/Labour - Steel			Construction /Labour - PE				EA& Archealogical Costs	Overheads	Company Labour, X-Ray, Construction Survey, Legal, Mill Inspection and Consultants	Station
	NPS 6	NPS 4	NPS 2	NPS 6	NPS 4	NPS 2	NPS 1 1/4	NPS 6	NPS 4	NPS 2	NPS 6	NPS 4	NPS 2	NPS 1 1/4				
Kettle Point and Lambton Shores				$24.87	$12.32	$3.36					$93.44	$51.46	$40.92		$40,000	$59,373	$40,157	$286,614
Milverton		$25.84			$12.36	$3.36			$79.14			$60.59	$36.02		$50,000	$124,132	$237,636	$286,614
Moraviantown					$9.38	$3.08	$1.57					$44.84	$28.51	$28.52	$25,000	$56,674	$10,000	
Prince Township					$11.54	$3.14	$1.88					$94.47	$57.61	$29.71	$50,000	$150,409	$11,000	

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 1, Appendix H

a) Please provide a redline version of the revised Distribution New Business Guidelines.

Response:

Please see the response at Exhibit B.Energy Probe.18 a).