

March 21, 2016

BY COURIER & RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

RE: EB-2016-0004 – Natural Gas Expansion Generic Proceeding – Union Gas Limited (“Union”) – Evidence

Please find attached Union Gas Limited’s evidence for the above-noted proceeding. This evidence is filed pursuant to the Ontario Energy Board’s (“the Board”) Procedural Order No.2 (dated March 9, 2016).

Union has structured its evidence to respond to each of the Issues identified in the Board’s approved Issues List (see Schedule B to Procedural Order No.2).

Should you have any questions on the above or would like to discuss in more detail, please contact me at 519-436-5476.

Yours truly,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

Encl.

cc: EB-2016-0004 Intervenors
Charles Keizer, Torys

1 **PREFILED EVIDENCE**

2

3 In a letter dated January 20, 2016, the Ontario Energy Board (“the Board”) informed all
4 parties that it intended to proceed with a generic hearing on its own motion as the issues
5 raised by all the parties were common to all gas distributors and new entrants seeking to
6 provide gas distribution services in communities that do not have access to natural gas. The
7 Board also made a determination that Union’s EB-2015-0179 Community Expansion
8 application would be put on hold. The Board further ruled that the application and evidence
9 Union Gas Limited (“Union”) filed as part of EB-2015-0179 would form part of the record of
10 the generic proceeding.

11

12 Pursuant to the Board’s EB-2016-0004 Procedural Order No. 2 (dated March 9, 2016)
13 attached is Union’s evidence submission. Union has structured its submission to respond to
14 each of the issues identified on the Board’s Issues List (see Schedule B to Procedural Order
15 No. 2). Union submits that a number of such issues were not addressed as part of its EB-
16 2015-0179 application and evidence.

17

18 Union’s evidence is further supported by a review of funding mechanisms adopted for
19 community expansion projects in place across North America by London Economics
20 International (“LEI”). Specifically, LEI’s review focused on the following two questions:

21 i) What funding mechanisms are adopted for community expansion projects, for

1 example from existing and/or new ratepayers? and,

- 2 ii) What requirements, if any, are placed on incumbent utility customers to help fund
3 expansion projects for new or other utilities?
4

5 A report prepared by LEI (“LEI Report”) is attached at Schedule 1.
6

7 **1. Issue**

8 *What is considered a community in the context of this proceeding?*
9

10 Union proposes that in the context of expanding natural gas to additional rural, northern,
11 and First Nations communities, a community be defined as a non-gas serviced geographic
12 area which consists of a minimum of 50 existing homes and businesses, as noted in EB-
13 2015-0179 Exhibit A, Tab 1, p. 1. The rationale for this definition is provided in EB-2015-
14 0179, Exhibit B.VECC.11.
15

16 **2. Issue**

17 *Does the OEB have the legal authority to establish a framework whereby the customers*
18 *of one utility subsidize the expansion undertaken by another distributor into*
19 *communities that do not have natural gas service?*

1 The Board’s jurisdiction under the *Ontario Energy Board Act* (the “Act”) is broad. The
2 Board may make orders approving or fixing just and reasonable rates for the distribution of
3 gas and, in so doing, the Board may adopt “any method or technique that it considers
4 appropriate”.

5
6 However, Union maintains that the Board’s jurisdiction, while broad, does not include
7 authority to require that Union’s customers subsidize the expansion undertaken by another
8 distributor into communities that do not have natural gas service. Union’s response to EB-
9 2015-0179, Exhibit B.Staff.2 b) states, “... *as there is no explicit legislative authority for*
10 *the Board to create such a mechanism, it is questionable that the Board could enact such a*
11 *mechanism even if it was so inclined.*”

12
13 Furthermore, express authority to establish such a subsidy regime is required because rates,
14 established in the absence of such a regime, would not be established in accordance with
15 the just and reasonable standard:

16
17 1. If the rates Union is required to charge its customers were to include amounts that would
18 be used as a subsidy for other distributors, that portion of Union’s rates would not be based
19 upon any underlying costs incurred by Union to serve its customers. Rather, that portion of
20 Union’s rates would be based on the costs incurred by another utility to serve its
21 customers. To the extent that Union’s rates are based upon such costs that are unrelated to

1 the regulated service that it provides, such rates would not be in accordance with the just
2 and reasonable standard.

3
4 2. Imposing a charge on Union's customers for purposes of subsidizing another utility's
5 cost of service would be contrary to the established ratemaking principle of "benefits
6 follow cost". Union's customers would be incurring costs without receiving any
7 corresponding benefits. On the flip side, another utility's customers would be receiving a
8 benefit without incurring any corresponding costs. To establish rates on this basis would
9 not be consistent with the just and reasonable standard. This would be comparable to
10 having Union's customers pay more to subsidize an industrial customer's cost of labour. It
11 is unrelated to any aspect of the service to Union's customers.

12
13 3. Subsidization would also be contrary to the standalone principle of ratemaking, which
14 holds that only those costs and risks that pertain to the activities of a regulated utility in
15 respect of the provision of service to ratepayers should be reflected in the revenue
16 requirement of that utility. To charge a subsidy would be to include in Union's revenue
17 requirement costs that are unrelated to the activities of the regulated utility. Alternatively,
18 it would mean that amounts would be included in rates that are in addition to Union's
19 revenue requirement. This too would be contrary to the just and reasonable standard.

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

7
8 **3. Issue**

9 *Based on a premise that the OEB has the legal authority described in Issue #1, what are*
10 *the merits of this approach? How should these contributions be treated for ratemaking*
11 *purposes?*

12
13 As stated in response to Issue 2, Union does not accept the premise that the Board has the
14 legal authority to establish a framework whereby the customers of one utility subsidize the
15 expansion undertaken by another. Union sees no merit in this approach. In response to
16 EB-2015-0179, Exhibit B.Staff.2 b) Union said it would be "inappropriate" for start-up
17 utilities to be financed by existing utility ratepayers.

18
19 **4. Issue**

20 *Should the OEB consider exemptions or changes in the EBO 188 Guidelines for rural,*
21 *remote and First Nation community expansion projects?*

1 Because economic feasibility is the most critical barrier to expansion to additional rural
2 and northern communities, Union proposes that specific exemptions or changes to the
3 E.B.O. 188 Guidelines be adopted to mitigate this barrier. In its February 18, 2015 letter¹
4 inviting parties to propose plans for expansion the Board indicated that the requirements of
5 E.B.O. 188 “may require some flexibility”, and Union’s proposal², filed in July 2015,
6 included a number of elements to address barriers presented by the current regulatory
7 construct.

8
9 ***a) Should the OEB consider projects that have a portfolio profitability index (PI) less***
10 ***than 1.0 and individual projects within a portfolio that have a PI lower than 0.8?***

11
12 Yes, the Board should consider portfolios and projects with PI’s of less than 1.0 and 0.8,
13 respectively. A portfolio by its nature is a collection of various projects and as such,
14 individual projects in and of themselves do not have a Portfolio PI. In this light,
15 Union’s interpretation of the question is “Should the Board allow portfolios to include
16 projects that have a PI below 0.8, and if so, should the Board allow for the PI of the
17 Portfolio containing those projects to drop below 1.0?”

18
19 The core issue underlying this question is to what extent is cross subsidization of
20 expansion within a utility from existing customers, or from other new customers added

¹ EB-2015-0179, Exhibit A, Tab 1 (Updated), Appendix A, p. 3

² EB-2015-0179, Filed July 23, 2015

1 in the same year, appropriate? Union proposes that limited levels of cross subsidization
2 are in the public interest. Please reference Union’s proposal at EB-2015-0179, Exhibit
3 A, Tab 1 (Updated), Section 4.3 (p. 24), Section 4.4 (p. 29), and Section 7 (p. 38) for
4 further details on Union’s submission.

5
6 The Board’s Filing Guideline on the Economic Tests for Transmission Pipeline
7 Applications (EB-2012-0092) states: “*The Board continues to hold the opinion that it is*
8 *appropriate for existing customers to subsidize, through higher rates, financially non-*
9 *sustaining extensions that are in the overall public interest if the subsidy does not cause*
10 *an undue burden on any individual, group, or class.*”³ It is Union’s position that this
11 opinion of the Board should not be limited to transmission pipeline applications.

12
13 The intent of the E.B.O. 188 Guidelines is to facilitate the expansion of natural gas
14 service while holding other customers harmless from the cost of new connections.
15 Setting the minimum Investment or Rolling Portfolio PI at 1.0 holds other customers
16 harmless. The E.B.O. 188 provision allowing for individual projects to be completed at
17 PI’s between 0.8 and 1.0 enables subsidization from some new customers to other less
18 profitable new customers each year. However, if a Portfolio PI remains above 1.0, the
19 new customers will actually be subsidizing existing customers over the longer term.

³ EB-2012-0092, Appendix A, item 13 (dated February 21, 2013)

1 Even if the Board is unable to accept the concept that a limited level of cross
2 subsidization from existing to new customers is in the public interest, enabling lowered
3 individual project threshold PI's to below 0.8 is appropriate. The rationale for this is
4 that Union's recent Rolling Project Portfolio history has resulted in a positive NPV
5 averaging \$14.6 million⁴ per year over the most recent three years, and a similar pattern
6 has existed for an extended number of years. Absent the provision of a minimum
7 project PI threshold of 0.8, this annual \$14.6 million favourable NPV could have been
8 used to support additional projects at PI's lower than 0.8 even without a need for
9 subsidization from existing customers.

10
11 ***b) What costs should be included in the economic assessment for providing natural gas***
12 ***service to communities and how are they to be determined and calculated.***

13
14 Union agrees with the cost factors to be considered in economic assessments outlined in
15 the E.B.O. 188 Guidelines⁵. Union proposes several clarifications or adjustments to
16 economic assessment factors in E.B.O. 188 as noted below.

17
18 Upstream Reinforcement of Distribution System

19 In addition to the costs outlined in E.B.O. 188, Union proposes that, subject to several
20 conditions, costs for upstream distribution system reinforcement be included in the

⁴ EB-2015-0179, Exhibit A, Tab 1 (Updated), Table 6, p. 38

⁵ E.B.O. 188 Guidelines are provided in EB-2015-0179 at Exhibit A, Tab 1, Appendix C.

1 economic assessment for any new attachments or load additions. The rationale for this
2 is the Board decision⁶ for the Wingham Expansion Project in 1995. In the Order
3 following this proceeding the Board indicated:

4
5 *“In future facilities applications Union is directed to... file an estimate of the costs of*
6 *any reinforcement of existing lines that may be necessary as a result of the specific*
7 *application, and an assessment of the impact of these costs on the economics of the*
8 *project;...”*

9
10 Union began applying the approach directed by the Board for a project to service Port
11 Elgin, Southampton and Wiarton⁷ in 1997. Because this direction came from the Board
12 subsequent to the development of the E.B.O. 188 Guidelines, it should be incorporated
13 in any revision to the Guidelines, subject to the conditions Union proposes below.

14
15 Where applicable, upstream distribution reinforcement cost assessment occurs in the
16 form of a combination of one or both of the following conditions:

17
18 1. The direct capital cost of the minimum required level of reinforcement is included in
19 the economic assessment for a connection if it is required at the time of the connection
20 in order to provide the capacity required for that connection.

⁶ E.B.L.O. 253, 1995

⁷ E.B.L.O. 259, 1997

1 2. In cases where adequate capacity is available in the upstream distribution system for
2 a new connection, but future expected upstream distribution reinforcement timing will
3 be accelerated to allow for other routine connections to the system, the Discounted Cash
4 Flow (“DCF”) includes a cost (“Advancement Charge”) to recognize the need for
5 planned future capital reinforcement investment earlier than would otherwise be
6 expected.

7
8 Union determines the Advancement Charge based on the difference between the NPV
9 of the revenue requirement of a reinforcement project in a given year, and the NPV of
10 the revenue requirement resulting from doing that same project in a later year.

11
12 Union proposes that Advancement Charges be restricted to situations where material
13 new attachments would result in a need to accelerate future reinforcement to within
14 three years following the year the attachment is put into service. The rationale for this
15 is as follows. Generally, unutilized system capacity is made available on a first come,
16 first served basis for any new load additions. However, Union attempts to ensure that
17 capacity is available for reasonably forecasted general service customer attachments for
18 a three year period. The reason for adopting a three year period is that the planning and
19 execution cycle for a major reinforcement project can extend that long, and Union
20 would not want to be in a position where a small customer would be unable to connect
21 because the system capacity has been fully exhausted.

1 In addition to the above condition, Union proposes that the need for upstream
2 reinforcement Advancement Charges be restricted to economic assessments where a
3 new attachment or load addition consists of a load of 200 m³/hour or higher. Union
4 proposes this level of load because it is material enough that it could have significant
5 impact on future reinforcement timing, and roughly corresponds to the annual load
6 which would qualify a customer for contract rates.

7
8 These two restrictions on upstream reinforcement Advancement Charges would strike
9 an appropriate balance between a desire not to overburden community expansion
10 projects with longer term reinforcement Advancement Charges when adequate capacity
11 is currently available, and a need to ensure that adequate capacity remains available in
12 the near term for routine general service customer attachments to the system.

13
14 Minimum Design Cost

15 As explained in EB-2015-0179, Exhibit B.LPMA.14, Union has historically based the
16 capital costs in the economic analysis of a project on the minimum pipeline system
17 design necessary to service the demand expected through the project's customer
18 forecast period. In some cases a project will be planned with a preferred design, for
19 example with increased pipe size, to account for other system needs. Union has not
20 historically included the cost premium for a preferred system design in the economic
21 analysis, and proposes that this practice be confirmed.

1 Revenues and Time Periods

2 Although costs are a key element of the economic assessment of an attachment,
3 reviewing appropriate costs in isolation without considering the other key elements of a
4 DCF analysis may not provide the Board with an appropriately balanced perspective
5 that would support a review of economic feasibility issues. Revenues and the terms
6 associated with costs and revenues are both fundamental inputs to the DCF analysis.
7 With this in mind, Union also accepts the basis for revenues and timeframes as outlined
8 in the E.B.O. 188 Guidelines, but would propose several adjustments as noted below:

9
10 i) Rate Based Revenue

11 E.B.O. 188 calls for the revenues in the economic assessment to be based on “*rates*
12 *derived from the existing rate schedules for the particular utility, net of the gas*
13 *commodity component*⁸” and accordingly, Union’s proposal incorporates this
14 requirement, and supplements it with a Temporary Expansion Surcharge (“TES”).
15 Because new entrants do not have existing rate schedules upon which to base the
16 revenues, Union assumes they would be required to develop a proposed rate schedule
17 that would allow for recovery of their full costs over the period of the economic
18 assessment. In contrast, existing rate schedules are derived in part from pre-existing
19 partially depreciated asset values. If new entrants will be required to develop a stand-
20 alone rate schedule which results in rates that allow a project to become economically

⁸ E.B.O. 188, Final Report of the Board, Appendix B, p. 4

1 feasible, while existing utilities are limited to applying their existing rate schedules, the
2 E.B.O. 188 requirement to use existing rate schedules creates a barrier for existing
3 utilities to compete with new entrants. This barrier is the result of the existing utilities
4 being unable to develop unique rate schedules that will reflect the costs of expansion.
5 For this reason Union proposes that the requirement to use existing rate schedules be
6 excluded from the Guidelines. Although Union continues to prefer to apply postage
7 stamp ratemaking principles as noted in its response to Issue 5, existing utilities should
8 not be prevented from resorting to community or project specific rates to make projects
9 feasible.

10
11 ii) Commercial/Industrial Revenue Time Period

12 Revenues for small (general service) commercial/industrial load additions should not be
13 limited to a 20 year period. Union understands the rationale for this restriction in
14 E.B.O. 188 is that the use of natural gas in a commercial or industrial building may
15 change over a longer time period as different businesses may occupy it. In the case
16 where loads are process loads, this is a valid concern. However, in cases where the
17 natural gas load is used for heating, it is very unlikely that this will change over a longer
18 timeframe. The building is very unlikely to be demolished if the incumbent business is
19 sold or closed, so at minimum, continued use of natural gas for heat should be included
20 in the economic assessment. For this reason, Union proposes that a maximum 40 year
21 term be used for heat and water heating load for commercial and industrial customers.

1 In other words, the revenues considered in the economic feasibility analysis for a new
2 business customer attachment can be based on up to 20 years for process loads, and up
3 to 40 years for heating. For clarity, Union's practice for large Commercial/Industrial
4 (contract rate) attachments is to base the economic analysis on the greater of 10 years,
5 or a time period that corresponds with the contract term necessary to achieve a PI of 1.0,
6 and Union proposes that this approach remains appropriate.

7
8 iii) Customer Forecast Time Period

9 Consideration should also be given to the customer forecast time horizon, which
10 E.B.O.188 Guidelines set at a maximum of 10 years. After the initial 10 year period, it
11 is likely that additional customers will attach to a new system when their heating system
12 requires replacement. Applying a general rule of thumb that typical heating equipment
13 has a life of up to 25 years would result in 4% of remaining potential customers
14 converting each year from year 11 to 25. Consequently, Union would propose the
15 maximum customer forecast period be extended from 10 to 25 years.

16
17 ***c) What, if any, amendments to the EBO 188 and EBO 134 Guidelines would be***
18 ***required as a result of the inclusion of any costs identified above?***

19
20 E.B.O. 188 Guidelines:

21 Please refer to Union's proposal in EB-2015-0179, Exhibit A, Tab 1 (Updated), Section

1 4.3 (p. 24) and Section 4.4 (p. 29) for details on proposed E.B.O. 188 Guideline
2 exemptions. For other amendments proposed in Issue 4 (b) above, appropriate detail
3 would have to be provided in the relevant section of the Guidelines provided in the
4 E.B.O. 188 Decision at Appendix B as noted below:

- 5
- 6 • Upstream Reinforcement: Section 2.1, Capital Cost item (c) - Provide clarification
7 that normalized system reinforcement costs apply at the Portfolio level, while
8 project specific reinforcement costs as noted above apply at a Project level.
- 9 • Minimum Design Costs: Section 2.1, Capital Cost item (a) - Clarify that costs are
10 for the minimum system design required to service the expected load through the
11 forecast period.
- 12 • Rate Based Revenue: Section 2.1, Revenue Forecasting item (e) - Eliminate the
13 requirement to use rates derived from the existing rate schedules.
- 14 • Commercial/Industrial Revenue Period: Section 2.2 (b) - Allow for up to 40 years
15 for commercial/industrial non-process related loads.
- 16 • Customer Forecast Time Period: Section 2.2 (a) - Allow for up to a 25 year
17 customer attachment horizon.
- 18

19 E.B.O. 134 Guidelines:

20 A review of E.B.O. 134 is not required in this proceeding. The Board reviewed E.B.O.
21 134 in the context of filing guidelines and issued adjusted guidelines February 21,

1 2013⁹. In the guidelines, the Board indicated:

2
3 *“These requirements apply to all Ontario Energy Board regulated gas utilities requesting*
4 *approval to construct new transmission facilities. For the purpose of these Guidelines*
5 ***transmission pipelines are defined as** any planned or proposed pipeline project that would*
6 *provide transportation services **to move natural gas on behalf of other shippers within***
7 ***Ontario.** Distribution system expansion pipelines that are subject to the filing guidelines*
8 *set in the E.B.O. 188 would not be subject to the proposed filing requirement.” (**Emphasis***
9 ***added**)*

10
11 Issue 4 (b) is specific to providing natural gas to communities through expansion of the
12 distribution system. Distribution system expansion is completed in accordance with
13 E.B.O. 188 guidelines, not E.B.O. 134, and as such, Union submits that E.B.O. 134
14 should not be in scope for this proceeding. In Union’s case, the current transmission
15 pipeline systems subject to the E.B.O. 134 Guidelines are limited to the Dawn Parkway
16 and Panhandle transmission systems.

17
18 *d) What would be the criteria for the projects/communities that would be eligible for*
19 *such exemptions? What, if any, other public interest factors should be included as*
20 *part of this criteria? How are they to be determined?*

⁹ EB-2012-0092

1 Criteria

2 Union proposes that projects that meet the definition of a community expansion project
3 (see Issue 1) would be eligible for exemptions. Please refer to Union’s proposal in EB-
4 2015-0179, Exhibit A, Tab 1 (Updated), (p. 1) line 18, Section 4.3 (p. 24), and Section
5 4.4 (p. 29).

6
7 Public Interest Factors

8 Union proposes that public interest factors be a consideration in setting criteria for
9 projects/communities to be eligible for exemptions from E.B.O. 188 as noted in Union’s
10 response to Issue 4 (f).

11
12 ***e) Should there be exemptions to certain costs being included in the economic***
13 ***assessment for providing natural gas service to communities that are not served? If***
14 ***so, what are those exemptions and how should the OEB consider them in assessing to***
15 ***approve specific community expansion projects?***

16
17 Union submits that all incremental costs for the minimum design of a project should be
18 included in the economic assessment for that project, subject to the exceptions noted
19 below. Any further proposed exemptions should be identified in the project specific
20 Leave-to-Construct (“LTC”) application on their own merits.

1 Upstream Reinforcement of Distribution System

2 Consistent with Union's submission for Issue 4 (b), Union proposes that Advancement
3 Charges for future upstream distribution system reinforcement not be included in the
4 economic assessment of a project in cases where reinforcement is not expected for a
5 period of 3 or more years following the year in which an attachment project enters
6 service. The rationale for this is included in Union's submission for Issue 4 (b).

7
8 Preferred Design Costs

9 Consistent with Union's submission for Issue 4 (b), Union proposes that any cost
10 premium for a preferred design over a minimum design not be included in the economic
11 assessment of a project. The rationale for this is provided in Union's submission for
12 issue 4 (b).

13
14 Upstream Reinforcement of Transmission System

15 It is Union's position that upstream transmission¹⁰ and storage costs should continue to
16 be excluded from the economic assessment of a distribution project. Only incremental
17 directly attributable costs are appropriate to include as compared against incremental
18 revenues. Upstream transmission and storage assets must be constructed in advance of
19 a distribution project in order to provide gas service. Typically transmission and storage

¹⁰ As defined in EB-2012-0092

1 systems include a number of years of distribution growth capacity due to the nature of
2 the time to construct facilities and the “lumpy” nature of the capacity created.

3
4 To recognize the differences in dates of construction, Union applies the “distribution”
5 portion of the rate schedule in assessing economic feasibility of distribution assets, the
6 “transmission” portion of the rate schedule at the time of assessing feasibility of
7 transmission projects, and in prior years when regulated storage assets were being
8 constructed, the “Storage” margins were included in assessing feasibility of storage
9 assets.

10
11 This approach recognizes upstream costs and revenues at the time the upstream assets
12 are proposed. Union submits this approach continues to be appropriate and results in all
13 costs and revenues being included at the appropriate time.

14
15 ***f) Should the economic, environmental and public interest components in not***
16 ***expanding natural gas service to a specific community be considered? If so how?***

17
18 Union proposes that in cases where a community expansion project or collection of
19 projects is not economically feasible, as demonstrated by a PI of 1.0 or better in a Stage
20 1 DCF analysis, public interest factors should be considered in assessing whether to
21 proceed with the projects. However, Union submits that a further assessment of the

1 impacts of not proceeding with a project should not be required. An assessment of not
2 proceeding would be broader and much more complex than an assessment of the
3 impacts of proceeding, as it would require a public policy view that would be very
4 difficult for project proponents to quantify or assess. For example, an assumption on
5 potential negative impacts on the community if businesses elect to move to other
6 communities because of high energy costs would be required. Union does not believe
7 this additional perspective would be of meaningful assistance to the Board in evaluating
8 project applications.

9
10 Union provides a high level assessment of the broader economic impact of proceeding
11 with expansion of natural gas infrastructure in EB-2015-0179, Exhibit A, Tab 1
12 (Updated), Section 7 (p. 36). In addition, EB-2015-0179, Exhibit B.CCC.5, and the
13 related report prepared for the Canadian Gas Association (“CGA”) filed as Attachment
14 1, indicates significant public benefits to expansion to additional communities.

15 Union proposes that public interest factors include but are not limited to the following:

- 16 • The energy cost savings available to customer who connect to the project;
- 17 • The incremental municipal taxes available to the community as a result of the
18 project;
- 19 • The GDP impact of the project;
- 20 • Projected employment impacts of the project;
- 21 • The environmental benefits of the project;

- 1 • Incremental government revenues attributable to the project; and,
2 • The local benefit to the municipality related to the ability to attract or retain
3 businesses and grow.

4
5 A description of many of these factors is provided in the CGA report referenced above.

6
7 E.B.O. 134, which provides guidelines for assessment of natural gas transmission
8 projects, provided for use of further economic assessment to enable understanding of
9 the public benefits of expansion. This assessment takes the form of both a Stage 2 and
10 Stage 3 DCF analysis, as outlined in Union’s proposal, which also provides the results
11 of a Stage 2 assessment¹¹. This type of analysis was not deemed necessary for
12 distribution projects in E.B.O. 188, since the Guidelines include minimum portfolio PI’s
13 of 1.0 or greater, which supported the intent of ensuring that existing ratepayers were
14 held harmless from the cost of expansion to new customers. Consistent with Union’s
15 proposal that limited levels of subsidization from existing ratepayers is in the public
16 interest, Union proposes that Stage 2 and Stage 3 analysis are an appropriate means of
17 considering the broader public benefits of Community Expansion Projects on a
18 collective basis.

19
20 A Stage 2 or 3 DCF analysis provides an indication of the broader benefits of

¹¹ EB-2015-0179, Exhibit A, Tab 1 (Updated) p. 38

1 Community Expansion Projects based on quantifiable as well as non-quantifiable public
2 interest factors. The results of a Stage 2 or Stage 3 analysis can then be compared to the
3 Stage 1 DCF analysis in order to determine the relative public benefits of proceeding
4 with the projects. Union proposes that a Stage 3 analysis only be required if the sum of
5 the results of the Stage 1 and Stage 2 analysis does not provide a positive NPV.
6

7 **5. Issue**

8 *Should the OEB allow natural gas distributors to establish surcharges from customers of*
9 *new communities to improve the feasibility of potential community expansion projects?*

10 *If so, what approaches are appropriate and over what period of time?*
11

12 Union supports the use of surcharges as proposed in EB-2015-0179, Exhibit A, Tab 1
13 (Updated), Section 4.1 (p. 15), and Section 4.2 (p. 23).
14

15 In addition to the rationale provided in EB-2015-0179, surcharges provide a mechanism to
16 allow for the expansion customers to make an additional contribution to financial
17 feasibility of a project over time, while providing a means to revert to postage stamp rates
18 once the surcharge period has expired. In other words, once the surcharge period has
19 expired customers in the expansion areas will see rates that are the same as rates in any
20 surrounding communities that previously had natural gas service.

1 Beyond this, surcharges provide a mechanism that can be applied to improve financial
2 feasibility of projects in the event the Board continues to require revenues in feasibility
3 assessments to be based on existing rate schedules, as noted in Union's response to Issue 4
4 (b).

5
6 Union continues to prefer to apply postage stamp ratemaking principles wherever possible
7 and for this reason would consider the application of a temporary surcharge to support
8 project feasibility prior to the application of a community or project specific rate.

9
10 Further to the above, Union proposes that surcharges not be limited to Community
11 Expansion Projects as noted in EB-2015-0179, Exhibit A, Tab 3.

12
13 **6. Issue**

14 ***Are there other ratemaking or rate recovery approaches that the OEB should consider?***

15
16 Although there may be alternate ratemaking and/or rate recovery approaches to that
17 proposed by Union as part of EB-2015-0179, Union maintains its ratemaking and rate
18 recovery proposal best meets the Board's *just and reasonable* standard. This proposal, for
19 the most part¹², is aligned with the ratemaking proposals filed and approved in Union's
20 most recent major capital expansion projects that warrant capital pass-through treatment.

12 EB-2015-0179, Exhibit JT1.14 provides a comparison with IRM Capital Pass Through mechanism.

1 As highlighted in its response to EB-2015-0179, Exhibit B.Staff.3, Union structured its
2 EB-2015-0179 proposal to meet the government's goal to complete the maximum number
3 of projects, while at the same time Union applied its experience, judgment and regulatory
4 precedent to minimize ratepayer impact. At the same time, it is Union's position that the
5 Board should avoid, where possible, prescriptive ratemaking approaches and allow utilities
6 to bring forward rate proposals that can be reviewed on their merits. It is important that
7 utilities be allowed to maintain flexibility to propose their own rate proposals based on the
8 public interest and the just and reasonable standard.

9
10 **7. Issue**

11 *Should the OEB allow for the recovery of the revenue requirement associated with*
12 *community expansion costs in rates that are outside the OEB approved incentive*
13 *ratemaking framework prior to the end of any incentive regulation plan term once the*
14 *assets are used and useful?*

15
16 Union supports an allowance for the recovery of the revenue requirement in rates that is
17 outside the Board approved incentive regulation framework as proposed in EB-2015-0179,
18 Exhibit A, Tab 1 (Updated), Section 4.5 (p. 32).

19
20 **8. Issue**

21 *Should the OEB consider imposing conditions or making other changes to Municipal*

1 ***Franchise Agreements and Certificates of Public Convenience and Necessity to reduce***
2 ***barriers to natural gas expansion?***

3
4 Union does not support a need for changes to Municipal Franchise Agreements or
5 Certificates of Public Convenience and Necessity (“Certificates”). However, Union
6 proposes that the Board consider several issues in making decisions to award either of the
7 aforesaid approvals to an LDC.

8
9 The current Model Franchise Agreement was developed in 2000 through an extensive
10 Board hearing process, and the decision from that proceeding was the result of extensive
11 negotiation and compromise spanning the municipalities and the gas utilities. Union does
12 not believe that the current Model Franchise Agreement imposes any specific barriers to
13 expansion. Making any modifications to the current Model Franchise Agreement would in
14 all likelihood be an extensive process, and Union does not support a need for review of or
15 change to existing agreements. Further to this, Union proposes that the current Model
16 Franchise Agreement continue to be adopted by all parties across the Province, as opposed
17 to allowing broad variations in Franchise Agreements to begin to occur. Any variations
18 from the current Model Franchise Agreement should be discouraged. If changes are to be
19 made, they should be reviewed and scrutinized by the Board in an open and public hearing
20 process prior to approval.

1 As noted in EB-2015-0179, Exhibit B.CCC.4, Union believes that a municipality can have
2 multiple Franchise Agreements with various gas distributors, and as such, the existence of
3 a pre-existing Franchise Agreement does not create a barrier to other gas distributors
4 indicating interest in serving a community that is not currently serviced. In contrast, the
5 Certificates provide for exclusive rights to distribute natural gas to a specific geographic
6 area. However, Union believes the Board can review and amend the geographic area
7 covered by a specific Certificate through an application to do so. For this reason Union
8 does not see a need to review or adjust the Certificates in general. If a pre-existing
9 Certificate needs to be amended in order to accommodate a different gas distributor
10 providing service, the application for LTC approval for the project should include a request
11 to amend the Certificate. Union does not support a need to allow for more than one LDC
12 to hold a Certificate for any specific geographic area, because having more than one utility,
13 for example, installing main on the same street, would clearly not be in the public interest.

14
15 Union proposes that prior to gaining consent to a Municipal Franchise Agreement, a utility
16 should be obligated to fully inform the municipality of the rates that will be charged to
17 consumers in the municipality when the system is put into service and any conditions
18 associated with those rates. In situations where multiple parties are interested in providing
19 natural gas service to a community, the municipalities should be aware of the comparative
20 rates and conditions that each party would intend to apply.

1 This proposal would ensure an appropriate level of transparency in the dialogue that any
2 utility interested in offering service might have with the communities. In the absence of
3 this condition, municipalities could agree to exclusively support project proponents without
4 understanding whether the resulting rates will be in the best interest of consumers and
5 businesses in those communities. Consequently a community could end up supporting a
6 proposal that would result in higher rates than surrounding (currently served)
7 municipalities, which would defeat their interest in offering energy costs that are
8 competitive with other municipalities.

9
10 In cases where pre-existing Board approved rate schedules are not available, this
11 requirement would be of necessity either require the Board to approve rates before a
12 Franchise is approved, or delay the franchise approval process until such time as rates are
13 approved by the Board. Further to this, before approving a Municipal Franchise
14 Agreement and Certificate, the Board should consider any other options available to the
15 municipality for gaining natural gas service.

16
17 One element of the Board’s mandate is the requirement to “*facilitate the maintenance of a*
18 *financially viable gas industry for the transmission, distribution and storage of gas*¹³”, and
19 further to this the Board’s mission is “*to promote a viable, sustainable and efficient energy*
20 *sector that serves the public interest and assists consumers to obtain reliable energy*

¹³ Ontario Energy Board Act, 1998, Part 1, Section 2.5;

1 *services that are cost effective.*¹⁴” Prior to Board approval of newly established Franchise
2 Agreements or Certificates, Union proposes that the Board should ensure that any utility
3 proposing to provide natural gas service to a community will be capable of meeting
4 minimum requirements of an LDC, which include but are not limited to the following:

5
6 1. Demonstrated operational capability, for example:

- 7 • Licensed by TSSA as a Natural Gas Distributor
- 8 • Demonstrated experience as a natural gas local distribution company
- 9 • A distribution system design that will deliver acceptable levels of reliability
- 10 • An existing safety and loss management system that provides for the protection of
11 people, the environment, and property.
- 12 • An existing Emergency Response Plan
- 13 • 24 x 7 call handling and emergency response capability
- 14 • Ability to train and certify field staff
- 15 • An existing billing system and related processes
- 16 • Engineering and system planning capability
- 17 • A System Integrity Management program
- 18 • Gas supply procurement capability
- 19

¹⁴ OEB Web Site: <http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/What+We+Do>

1 2. Ability to meet core expectations that the Board has of existing gas utilities in Ontario.

2 Examples include but are not limited to:

- 3 • Meet and report on OEB Service Quality Requirement Performance Metrics (“Gas
4 Distribution Access Rule”)
- 5 • Comply with Affiliated Relationships Code (“ARC”) requirements
- 6 • Deliver DSM Programs
- 7 • Provide low income emergency financial assistance (LEAP funding)
- 8 • Deliver a plant damage prevention program
- 9 • Comply with future government policy mandates (i.e. Cap and Trade Program)

10
11 3. Demonstrated Financial Stability as noted below:

12 Prior to the Board approving a Franchise Agreement or a Certificate to provide service to
13 any areas within Ontario that do not currently have access to natural gas, the Board should
14 be satisfied that the gas distributor has access to sufficient capital to complete the project as
15 well as operate the LDC for an initial period until such time as the annual revenues from
16 customers are sufficient to cover annual operating costs. To demonstrate they are
17 financially able to provide service to customers a new entrant should have to show how
18 they expect to finance the operation. In order to assess this, the Board needs to know the
19 funding required to construct and to operate the system.

20
21 While credit worthiness is one measure in order to determine if a new entrant has the

1 necessary financial viability, the Board should also review the utility’s financial plan
2 specific to the expansion and operation that is the subject of the Certificate. Being able to
3 test assumptions around costs, rates, timing and extent of customer conversions and
4 sensitivity to variation in those assumptions would be critical to demonstrate financial
5 viability.

6
7 The Board may consider whether it would be appropriate to require new entrants to file
8 quarterly financial statements prior to approving a Franchise Agreement or a Certificate.

9
10 In the absence of the Board considering these types of requirements, Union would be
11 concerned with how the Board can fulfil the “viability, sustainability and efficiency of the
12 natural gas energy sector” component of its mission. Further to this, if the Board’s
13 expectations of new entrants are not the same as expectations of existing utilities, the
14 ability of existing utilities to compete on a level playing field with new entrants to extend
15 service to new areas would be seriously jeopardized.

16
17 **9. Issue**

18 *What types of processes could be implemented to facilitate the introduction of new*
19 *entrants to provide service to communities that do not have access to natural gas. What*
20 *are the merits of these processes and what are the existing barriers to implementation?*
21 *(e.g. Issuance of Request for Proposals to enter into franchise agreements.)*

1 The identified issue presupposes a need to encourage new entrants to provide service to
2 communities that do not have access to natural gas, without addressing the question of
3 whether there is in fact a need for new entrants. Union believes the Board should also be
4 considering whether new entrants will be able to satisfy the public interest in a manner
5 comparable to the existing utilities. Union has indicated a strong interest in providing
6 service to these communities and notes that Enbridge Gas Distribution indicated at the Pre-
7 hearing Conference for EB-2015-0179¹⁵ that it planned to submit evidence indicating their
8 intent to propose an approach similar to that of Union.

9
10 The most significant barrier to expansion to additional communities is economic in nature.
11 The challenge, then, is one of either making projects less costly so that they can meet
12 required economic feasibility criteria, or adjusting the feasibility criteria. Union does not
13 believe that there are cost reduction opportunities that would reduce the capital costs of
14 expansion significantly enough to overcome the financial viability barrier that currently
15 exists. For this reason, Union has proposed adjusting the criteria. Union submits that an
16 effort by the Board to encourage RFI or RFP processes and competition from multiple
17 parties to service any specific area will not be helpful if projects proposed by new entrants
18 still need to meet the current E.B.O. 188 criteria.

19
20 In situations where more than one party wants to serve an area both parties can bring

¹⁵ EB-2015-0179 Pre-Hearing Conference, Transcript, p. 14

1 Franchise, Certificate, and LTC applications to the Board as applicable, or intervene in
2 another party's application, and the Board will determine which application (or part
3 thereof) to move forward with. This approach has precedent, established with the
4 Markdale/Flesherton/Dundalk project¹⁶ in 1996. The Board cannot make a determination,
5 however, without knowing the proposed rates and resulting impacts to customers. In order
6 to meet the Board's Public Interest Test, as noted in Union's response to Issue 8, rate
7 impacts need to be known as they are a key determinant to any expansion project/proposal.
8 Encouraging a municipality to have an RFI or RFP process in the absence of requiring an
9 understanding of the costs and rates inherent in any proposal reviewed as part of that
10 process can only result in a non-binding outcome and potential unmet expectations, since
11 the Board is required to approve both the Franchise Agreements and applicable rates.

12
13 Union believes that encouraging existing LDC's to expand their systems as opposed to
14 encouraging new entrants is highly likely to result in a more efficient natural gas sector in
15 Ontario, which is aligned with the Board's mission to *"to promote a viable, sustainable
16 and efficient energy sector that serves the public interest and assists consumers to obtain
17 reliable energy services that are cost effective."*¹⁷ The primary reason that expansion by
18 the existing utilities would be more efficient is that the existing utilities have already
19 established the required supporting administrative infrastructure (both people and assets)
20 required to be an effective natural gas distributor in Ontario. Costs for that infrastructure

¹⁶ EBLO 252

¹⁷ OEB Web Site: <http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/What+We+Do>

1 have been reviewed and considered prudent through the Board's rate setting process.

2 Consequently the costs for the existing utilities to expand would be limited to costs that are
3 incremental (variable) to the existing utility's operations. The fixed costs of the necessary
4 administrative support capability would not increase with the addition of new customers
5 for an existing gas LDC; in fact the overall fixed costs would on a per customer basis
6 decrease. Some examples of this administrative support capability and infrastructure
7 include the following:

- 8 • Call Centre infrastructure
- 9 • 24 x 7 call handling and emergency response infrastructure
- 10 • Billing system development and Billing Centre infrastructure
- 11 • Regulatory, Legal, and Finance Support
- 12 • Field operations support and infrastructure (Planning and Dispatch functions)
- 13 • IT/IS systems
- 14 • Engineering and Planning
- 15 • Procurement
- 16 • Buildings
- 17 • Management and Supervision
- 18 • Training and certification program delivery
- 19 • Plant damage prevention program

20 Union acknowledges that an experienced natural gas distributor who currently operates in a
21 North American jurisdiction and wishes to enter the Ontario market may have these

1 capabilities. However, a new entrant who is not currently a natural gas distributor would
2 be required to develop many or all of these capabilities and would be expected to pass the
3 costs of developing them on to the consumers in the new communities they serve.

4
5 The Ontario government has encouraged electric LDC consolidation for a number of years.
6 The 2015 Ontario budget signalled continued support for this effort, indicating “*To further*
7 *incent efficiencies through consolidation and to benefit ratepayers, the Province is also*
8 *taking steps to lower the transfer tax on municipally owned electricity utilities and address*
9 *other potential tax implications of consolidation,..*”.¹⁸ Board attempts to encourage new
10 entrant natural gas LDC’s appears to be in conflict with Provincial efforts to encourage
11 Electric LDC consolidation. For this reason Union questions whether encouraging new
12 entrants should be a key component of the Board’s efforts to encourage expansion of gas
13 distribution systems to additional northern and rural communities.

14
15 As noted in Union’s response to Issue 8, Union believes more in-depth assessment of the
16 impact of a project as well as the LDC proposing service is required prior to gaining
17 municipal consent to a Franchise Agreement. For these reasons Union does not believe a
18 municipally administered RFI or RFP process is an appropriate approach to encouraging
19 the extension of natural gas service to additional communities. If an RFI or RFP process is
20 encouraged, the Board should be heavily engaged in that process. Union believes that the

¹⁸ 2015 Ontario Budget, p. 82

1 Board is much better suited to provide the expertise necessary to appropriately assess the
2 capabilities or financial viability of a potential LDC, and of a project to provide service,
3 than individual municipalities. Since the Board is required to approve the LTC application
4 and the Franchise Agreement as well as issue the necessary Certificate, as applicable, an
5 RFP process solely administered by a municipality may result in projects being proposed
6 that are less able to meet the public interest than otherwise.

7
8 **10. Issue**

9 *How will the Ontario Government's proposed cap and trade program impact an*
10 *alternative framework that the OEB may establish to facilitate the provision of natural*
11 *gas services in communities that do not currently have access?*

12
13 Union's EB-2015-0179 Community Expansion application responded to the Board's
14 initiative to address the Ontario government's goal of ensuring that "*Ontario consumers in*
15 *communities that currently do not have access to natural gas are able to share in*
16 *affordable supplies of natural gas.*¹⁹" In addition, the application responded to a need
17 expressed by consumers in those communities, as well as municipal and provincial
18 representatives, for more energy choices. Union outlined the benefits of its Community
19 Expansion proposal in EB-2015-0179, Exhibit A, Tab 1, pp. 9-13.

¹⁹ EB-2015-0179, Exhibit A, Tab 1, p.1

1 Union's Community Expansion application also recognized that expanding natural gas
2 distribution systems in line with the Ontario government's goal would increase natural gas
3 use, and thus may appear to be inconsistent with the Ontario government's intent to
4 implement a cap and trade program whose objective is to significantly reduce greenhouse
5 gas emissions. However, natural gas has lower greenhouse gas emissions than other fossil
6 fuels such as furnace oil and propane, which would be displaced with increased access to
7 natural gas. As noted in Union's responses to EB-2015-0179, Exhibit B.CCC.5 and
8 Exhibit B.SEC.10, there is an estimated decrease in greenhouse gas emissions from the
9 projects in Union's Community Expansion application.

10
11 The impacts of the Ontario government's proposed cap and trade program are not yet
12 known. The Ontario government released its draft cap and trade regulations on February
13 25, 2016 and the enabling legislation on February 24, 2016. Certain components of the cap
14 and trade program that were not included in the draft cap and trade regulations (e.g.
15 offsets) will be issued as separate regulations. These components will also have a bearing
16 on the expected costs of the cap and trade program. The cap and trade regulations are
17 expected to be finalized in July, 2016.

18
19 The Board initiated a consultation to develop a natural gas regulatory framework to support
20 the implementation of Ontario's cap and trade program ("cap and trade framework") on

1 March 10, 2016²⁰. The cap and trade framework development is expected to be completed
2 by October, 2016 and will reflect the final cap and trade regulations and legislation. After
3 the cap and trade framework is finalized, natural gas distributors will file their utility-
4 specific applications with the Board.

5
6 Union believes the effects of Ontario's cap and trade program are best dealt with in a
7 future proceeding, once the impacts can be more specifically estimated given the details of
8 the cap and trade program and the regulatory framework.

9
10 **11. Issue**

11 *What is the impact of the Ontario Government's proposed cap and trade program on the*
12 *estimated savings to switch from other alternative fuels to natural gas and the resulting*
13 *impact on conversion rates?*

14
15 As outlined in Union's Community Expansion evidence (EB-2015-0179, Exhibit A, Tab 1,
16 pp. 9-10), there are significant price advantages of natural gas in comparison to propane,
17 furnace oil and electricity. Union expects that the Ontario government's proposed cap and
18 trade program will increase the cost of all fuels with associated greenhouse gas emissions.

19 Since natural gas has lower greenhouse gas emissions than furnace oil and propane, Union
20 expects the costs of these fuels will increase by at least as much as natural gas. The impact

²⁰ Consultation to Develop a Regulatory Framework for Natural Gas Distributors' Cap and Trade Compliance Plans (Board File No. EB-2015-0363) dated March 10, 2016.

1 on electricity prices will be lower due to the electricity fuel mix. However, Union believes
2 that natural gas will remain an economic option for customers in a low carbon economy as
3 the differential between natural gas and electricity is so high. Based on 2015 figures, the
4 estimated annual difference in energy cost between natural gas and electricity was
5 \$2,465²¹. Union does not foresee this substantial difference being eliminated through the
6 implementation of the Ontario government's cap and trade program.

7
8 **12. Issue**

9 *How should the OEB incorporate the Ontario Government's recently announced loan*
10 *and grant programs into the economic feasibility analysis?*

11
12 Union proposes that any loans or grants made available to municipalities by the Ontario
13 Government that are in turn directed by the municipalities to supporting expansion of the
14 gas system would be applied as a Contribution In Aid of Construction ("CIAC"), as noted
15 in EB-2015-0179 at Exhibit B.South Bruce.8. As such, loan or grant funding would be
16 applied against the gross capital cost of a project in the economic feasibility analysis.

17
18 Union's understanding is that the Ontario Government intends for the announced loans and
19 grants to be applicable to projects that regulatory flexibility on its own would not make
20 economically feasible, as noted in EB-2015-0179 at Exhibit B.CCC.16.

²¹ EB-2015-0179, Exhibit B.CPA.1, Attachment 1, p. 3

Economically efficient approaches to community expansion – expert assistance in the matter of Union Gas Limited’s community expansion application (EB-2015-0179)



prepared for Union Gas Limited by London Economics International LLC

March 18, 2016

London Economics International LLC (“LEI”) reviewed the funding mechanisms for community and rural utility expansion in place across various North American natural gas (New York, North Carolina and Nebraska), electricity (Ontario and Alberta) and telecommunication (USA and Canada) markets. Subject to the individual market characteristics including, but not limited to, political objectives and approaches to cost recovery, available funding mechanisms include: natural gas expansion ratepayers, internal utility cross-subsidization, jurisdiction-wide cross-subsidization, and taxpayer funding. While the direct costs of expansion specific to a customer, or customer group, should be borne by that customer or group, deviation from strict cost causation can be warranted in the case where public benefits arise. Where a utility has access to an existing customer base these costs may be internally socialized across all customers via cross-subsidies, provided the rates charged to individual customers (or customer groups) remain within economically efficient boundaries. Alternatively expansion of natural gas services, for example to rural communities in Ontario, may be categorized as a public good where substantial positive externalities accrue to all. The cost of expansion programs may therefore be recovered from all ratepayers or taxpayers within the province, as opposed to an individual utility customer base. The LEI team found no examples of customers of one utility subsidizing another’s except where all customers within a jurisdiction across multiple companies provided the funding.

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List of Acronyms

AFFB	Alberta Farm Fuel Benefit
AFREA	Alberta Federation of Rural Electrification Associations
Btu	British Thermal Units
CHP	Combined Heat and Power
CRTC	Canadian Radio-television and Telecommunications Commission
Enbridge	Enbridge Gas Distribution Inc.
EPCOR	EPCOR Utilities Inc.
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HCSA	High-cost Serving Areas
IESO	Independent Electricity System Operator
ILEC	Incumbent Local Exchange Carrier
ITE	Incremental Tax Equivalent
LDC	Local Distribution Company
LEI	London Economics International
LTEP	Long Term Energy Plan
NAS	Network Access Services
NCUC	North Carolina Utilities Commission
NPSC	Nebraska Public Service Commission
NYPSC	New York Public Service Commission
NYSEG	New York State Electric & Gas Corporation
OEB	Ontario Energy Board
PES	Primary Exchange Services
REA	Rural Electrification Association
REP	Rural Electric Program
RIS	Rural Infrastructure Surcharge
RRRP	Rural or Remote Electricity Rate Protection
SCT	Societal Cost Test
TCS	Temporary Connection Surcharge
TES	Temporary Expansion Surcharge
Union	Union Gas Limited
USF	Universal Service Fund
USAC	Universal Service Administrative Company

1 Executive Summary

Union Gas Limited (“Union”) engaged London Economics International LLC (“LEI”) to provide a high-level overview of the funding mechanisms adopted for community expansion projects across North America, and the requirements, if any, placed on an incumbent utility’s customers to help fund those expansion projects for new or existing suppliers.

This work follows Union’s application and pre-filed evidence (EB-2015-0179) submitted to the Ontario Energy Board (“OEB”) for expansion of its natural gas distribution network to unserved communities across Ontario. Filed on July 15, 2015, Union applied for various funding mechanisms applicable to its existing and expanding ratepayer base (including cross-subsidies between customer groups), as well as the municipalities benefiting from the expansion. Furthermore, Union sought exemption from key parameters of the current OEB guidelines for expansion of the network as outlined in the OEB’s report titled, “*Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*” (EBO 188), specifically the economic targets, measured by a profitability index, that were applied to individual projects and to Union’s planned portfolio of projects. The exemptions sought out reflect the assessed economic viability of certain projects covered as part of Union’s application, that fall outside of these targets.

Union’s application was a direct response to the OEB’s invitation of February 18, 2015 where all potential applicants with sufficient financial and technical expertise were invited to propose plans for natural gas expansion.¹ On January 20, 2016 the OEB announced a hold on Union’s application having recognized that key issues regarding funding of expansion projects may be common to all entities seeking to provide natural gas services to rural communities in the future. On February 10, 2016 the OEB commenced generic proceeding EB-2016-004 to discuss these issues in further detail.²

Natural gas expansion aligns with Ontario’s environmental and carbon reduction goals to reduce greenhouse gas pollution by 15% below 1990 levels by 2020, and 80% below 1990 levels by 2050, while also providing broader economic benefits for the province. These benefits include savings to both electricity and heating costs for customers (and municipalities) who switch from more expensive fuel types, as well as the creation of new jobs, additional tax benefits to municipalities and potential expansion of other industries.

To realize the environmental and economic benefits of natural gas expansion, Ontario must first ensure its ratemaking framework allows a utility to recover the costs of, and fair return on, its investment. Good utility rate design reflects a consensus between the utility, its ratepayers, and its regulators with regards to what is fair and practical. Similarly situated jurisdictions may develop radically different rate designs based on the differing weights that policymakers place

¹ OEB. *Letter Re: Expansion of Natural Gas Distribution*. February 18, 2015.

² OEB. *EB2016-0004 Procedural Order No. 1*. February 10, 2016.

on various objectives. Subject to the benefits generated for the province, costs of expansion may be fairly distributed across all rate or tax payers in the province. For example, an expansion project may be defined as a public good because of its ability to provide widespread environmental or economic benefits, and therefore, costs associated with this expansion project may be distributed across a broader customer base than solely those directly connected to the network.

In general the following principles should be adopted when considering rate design:

- **Cost causation and the avoidance of subsidies** - where possible customers should pay for those costs which are determined to be directly attributable to them in the provision of a service;
- **Financial stability and fair rate of return** – rates must be set at a level which enables a utility to meet its statutory obligations, while earning a fair rate of return and generating sufficient cash flow to support necessary investment;
- **Incentive compatibility** – rate design should provide for appropriate incentives, for example in terms of investment, service or consumption levels, to both the utility and customer;
- **Non-discrimination** – similarly situated customers should face similar terms and conditions and therefore similar rates; and
- **Administrative simplicity** – rates should be transparent and easy for customers to understand.

There are four main funding mechanisms that may be considered in order to fund community expansion projects as shown below. The choice between funding options is generally driven by individual characteristics of the markets in question including, but not limited to, state/province or federally mandated policy objectives, the number of service providers supplying the market, the volume of customers to be connected and the costs associated in doing so. Each mechanism reflects the general rate design principles identified above.

Funding mechanism	Description
Natural gas expansion ratepayers	Consumers of the natural gas are responsible for all the costs associated with the expansion of the natural gas distribution network into these areas
Internal utility cross-subsidization	Expansion costs are recovered from all customers of a utility by adjusting a utility's general rate base
Jurisdiction-wide cross-subsidization	Expansion costs may be recovered from all natural gas ratepayers within the jurisdiction
Taxpayer funded	Expansion is seen as a social benefit whose costs are borne by all tax payers

In conducting its analysis, LEI completed a high level review of the funding mechanisms in place across various North American natural gas, electricity and telecommunication markets. LEI has explored further the funding mechanisms adopted in certain jurisdictions as shown in Figure 2.

Figure 2. Sample funding mechanisms for community expansion programs adopted across North America

State/Country	Sector	Funding Mechanism
New York	Natural Gas	Internal utility cross-subsidization
North Carolina	Natural Gas	Taxpayer funding (via Government grants)
Nebraska	Natural Gas	Internal utility cross-subsidization
Ontario	Electricity	Provincial ratepayer cross-subsidization
Alberta	Electricity	Provincial ratepayer cross-subsidization
USA	Telecommunications	Federal ratepayer cross-subsidization
Canada	Telecommunications	Federal ratepayer cross-subsidization

In nearly all instances studied, the costs of expansion were subsidized either by the respective jurisdiction's ratepayers or taxpayers, existing ratepayers of the incumbent utility, or a combination of both. Our research indicates that cross-subsidization for rural expansion in each case does not require ratepayers of an existing company to bear the expansion costs of a new entrant or existing competitor. Instead, if charges are passed on to ratepayers they are done so in a uniform method whereby all ratepayers in the utility are charged equally, for example through a mark-up to existing rates applied to all ratepayers in a province or through the implementation of a broad based tax borne by all taxpayers.

Adoption of a cross-subsidy between an incumbent utility and a new entrant or other existing supplier is not a common approach to funding potential expansion projects, as it exacerbates known issues associated with other cross-subsidization methods, and violates the rate design principles specified above. For example, customers of an incumbent utility would be unfairly charged for costs that are not directly attributable to them, or attributable to the overall return earned by the utility. Further, these forms of cross-subsidization could result in a significant administrative burden, and eliminate the ability for currently cross-subsidizing customers to benefit in the future from economies of scale arising from the expansion projects as their economics improve.

An alternative approach to cross-subsidization within or between utilities would be to have the total costs socialized across all ratepayers or taxpayers thereby avoiding undue burden on a single utility's customer base. The Ontario government's policy position seeking to expand the natural gas distribution system would support the application of this mechanism and allow the realization of both the environmental and wider economic benefits that accrue as a result. Spreading the costs over a broader base would mute changes in consumption behavior while matching cost recovery with those who receive the environmental benefits.

2 Background and Scope of Work

2.1 Union's application

The provincial government of Ontario made a commitment as part of the 2013 Long Term Energy Plan ("LTEP") to "look at opportunities to expand natural gas services within the Province to areas that are not currently served."³ While almost all urban Ontario residents have access to natural gas, less than 20% of Ontario's rural residents can afford the same opportunity.⁴ Instead rural residents rely on higher carbon emitting fuels such as oil, propane, or higher priced electricity heat their homes and businesses.⁵

The recent focus on expansion of the natural gas distribution network is a direct response to the OEB's invitation on February 18, 2015 for "all potential applicants with sufficient financial and technical expertise to propose plans for natural gas expansion."⁶ On July 23, 2015 in response to the OEB's invitation, Union filed an application and evidence for the expansion of its natural gas distribution network to unserved communities across Ontario (summarized in Figure 3).⁷ The application provided for two distinct expansion project types:

- **Community Expansion Project:** system expansion project that 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 of less than 1.0; and
- **Small Main Extension Project:** all other forms of distribution expansion which provide first-time natural gas access to customers. These projects include the extension of mains and related service attachments, and service lines to individual commercial and industrial customers off existing mains.⁸

³ Ibid. In making this commitment the Ontario Minister for Economic Development, Employment and Infrastructure has detailed the following funding options available to market participants:

- \$200 million in Natural Gas Access Loans over two years to help communities partner with utilities to extend access to natural gas, and
- \$30 million in "Natural Gas Economic Development Grants" to accelerate projects with clear economic development potential.

⁴ Ontario Federation of Agriculture. *Turning up the heat for natural gas expansion in rural Ontario* (2013).

⁵ Ibid.

⁶ OEB. *Letter Re: Expansion of Natural Gas Distribution*. February 18, 2015.

⁷ Union Gas Limited. *Application EB-2015-0179 – Union Gas Limited ("Union") – Expansion of Distribution*. July 23, 2015.

⁸ Ibid.

Specifically, Union has identified approximately 29 projects with the capacity to provide natural gas services to around 18,000 homes and businesses in 33 rural or remote communities.⁹ The total forecasted cost for these projects was estimated to be \$135 million.¹⁰

Figure 3. Summary of Union’s application to the OEB

No.	Application for
1	Approval of a Temporary Expansion Surcharge rate for community expansion projects
2	Approval of an Incremental Tax Equivalent mechanism to collect municipal contributions
3	Exemption from EBO 188 allowing individual Community Expansion Projects to proceed at a profitability index of 0.4 or greater
4	Exemption of Community Expansion Projects from EBO 188 Investment Portfolio and Rolling Project Portfolio requirements
5	Approval of a capital pass-through mechanism to incorporate the Community Expansion Projects in rates immediately following their in-service dates
6	Approval to establish a Community Expansion Capital Pass-Through Deferral Account and a Community Expansion Contribution Deferral Account
7	Approval for rate recovery of the net revenue requirement for four Community Expansion Projects: Milverton; Prince Township; Chippewas of Kettle and Stony Point First Nation and Lambton Shores; and, Delaware Nation of Moraviantown.
8	Leave to construct approval for the natural gas pipelines and ancillary facilities required to serve the communities of Milverton; Prince Township; and, the Chippewas of Kettle and Stony Point First Nation and Lambton Shores.
9	Approval of a Temporary Connection Surcharge rate for main extension projects that are smaller and do not meet the Community Expansion Project criteria as identified in the written evidence that supports this application.

Source: Union Gas Limited. Application EB-2015-0179 – Union Gas Limited (“Union”) – Community Expansion – Evidence Update. December 14, 2015.

In developing the application, Union adopted the following principles:

- Customers and municipalities who directly benefit from Community Expansion Projects should contribute to the financial viability of the project.
- Expansion customer contributions to project feasibility should be commensurate with the savings achieved by switching to natural gas.
- Moderate cross subsidization from existing customers is acceptable, provided long term rate impacts are reasonable.
- Natural gas distributors should not be exposed to financial risk related to the incremental new community capital investments.¹¹

⁹ Union Gas Limited. Application EB-2015-0179 – Union Gas Limited (“Union”) – Community Expansion – Evidence Update. December 14, 2015.

¹⁰ Union Gas Limited. Application EB-2015-0179 – Union Gas Limited (“Union”) – Community Expansion – Evidence Update. December 14, 2015.

To recover the costs associated with the portfolio of expansion projects, Union proposed various funding mechanisms including:

- **Temporary Expansion Surcharge (“TES”)**: requires new Union customers attaching to expansion systems to dedicate a portion of their annual savings towards the cost of expansion for a defined period of time (up to 10 years);
 - Applicable to general service customers only (Rates M1, M2, 01, 10) where a contribution from a customer in excess of \$500 is required to make a project economically feasible;
- **Incremental Tax Equivalent (“ITE”)**: based on the incremental property taxes collected from Union the ITE is designed to allow for municipalities to contribute to the cost of a specific project;
 - Applicable to municipalities for a term equivalent to the TES wishing to pursue expansion projects with a reduced profitability index of below 0.8;
- **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;
 - It is intended for projects that do not meet the definition of a Community Expansion Project and do not qualify for reduced economic feasibility thresholds.

Union identified these funding mechanisms as a potential means to address existing barriers to funding the expansion of the natural gas distribution network to rural and northern communities. Specifically in designing of the above funding mechanisms, Union notes that the “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.”¹² Further accounting for the ITE, Union recognizes the economic development benefits associated with the expansion of the natural gas system (through incremental property tax revenue, reduced energy costs) to municipalities.¹³

Union has also proposed a separate funding mechanism providing for a cross-subsidy between existing ratepayers and new expansion ratepayers associated with the recovery of annual revenue requirements. These cross-subsidies range from \$0.71 to \$4.80 per annum for the 29 projects under consideration.¹⁴

¹¹ Union Gas Limited. *Application EB-2015-0179 – Union Gas Limited (“Union”) – Expansion of Distribution*. July 23, 2015.

¹² Ibid.

¹³ Ibid.

¹⁴ Union Gas Limited. *Application EB-2015-0179 – Union Gas Limited (“Union”) – Community Expansion – Evidence Update*. December 14, 2015.

In addition to the proposed funding mechanisms, and due to the economic viability of certain projects, Union's application sought exemption from parts of the economic tests outlined under the OEB's EBO 188 guideline. Specifically, Union has applied for exemption allowing individual projects to proceed with a profitability index of 0.4 or greater.¹⁵ Further exemption was requested in relation to the investment portfolio and rolling project portfolio requirements of the guideline. Where exemption is granted, Union have proposed a limit the rate impact on a current residential customer's bill to a maximum of \$24 per year for all current and future community expansion projects that it will complete.¹⁶

The application was the first of its kind and prompted a response from various stakeholders including industry associations, potential new and existing customers, as well as existing and potentially new natural gas distributors in Ontario such as Enbridge Gas Distribution Inc. ("Enbridge") and EPCOR Utilities Inc. ("EPCOR") respectively.¹⁷

EPCOR's comments regarding Union Gas' application to the OEB

In its December 2, 2015 letter to the OEB EPCOR considered Union's proposal "*discriminates against new gas utilities entering the province to provide service to unserved markets because they are not eligible to receive support funds [from existing customers]. These funds are available only to Union.*" Specifically EPCOR have indicated the TCS should be made available to any utility that qualifies on a fair and equitable basis. Further EPCOR noted the "*discriminatory nature of the manner in which this fund is administered compromises the use of a competitive bidding process by Municipalities to attract new utilities to provide natural gas service in unserved markets.*"¹ In further correspondence with the OEB on December 18, 2015 EPCOR expand on their argument noting "*a competitive bidding process is in the public interest.*"

Source: Gordon E. Kaiser Professional Corporation's letter to the OEB on behalf of EPCOR regarding EB-2015-0179 Union Gas Limited Community Expansion

EPCOR's arguments as presented in the textbox above indicate a desire for Union ratepayers to partially offset the costs of servicing new EPCOR ratepayers under its own expansion programs, thereby creating a cross-subsidy between Union's customers and new entrant or existing supplier customers.

Recognizing the issues associated with funding expansion programs are common to all natural gas distributors, the OEB put on hold Union's application and established a generic hearing to consider what mechanisms may be used to recover costs of expanding the natural gas services

¹⁵ In this instance a municipality would be required to agree to a binding commitment to make an ITE contribution for the established term of the TES.

¹⁶ Union Gas Limited. *Application EB-2015-0179 – Union Gas Limited ("Union") – Expansion of Distribution*. July 23, 2015.

¹⁷ A technical conference hosted by the OEB was held on December 15, 2015 to discuss the policy and financial matters related to the application.

across the Province.¹⁸ On January 20, 2016, the OEB announced its intention to put-on-hold Union's application in order to address key issues, potentially applicable to all distributors.

On February 10, 2016, OEB gave notice of the commencement of generic proceeding EB-2016-004 to consider what mechanisms may be used to recover the costs of expanding natural gas services to Ontario communities not already served.¹⁹ All evidence submitted, as well as intervenors participating in Union's community expansion application, are recorded as evidence or participants in the generic hearing.

In announcing the generic proceeding the OEB intends to review the following general issues:

- Should the OEB implement new ratemaking mechanisms including changes to current economic tests to encourage utilities to expand natural gas distribution service to new communities? If so, what should these new mechanisms be?
- Should the OEB consider imposing conditions or making other changes to Municipal Franchise Agreements and Certificates of Public Convenience and Necessity to reduce barriers to natural gas expansion?
- Does the OEB have the authority to require the ratepayers of one utility to subsidize the costs of another utility to expand into new communities? If so, under what circumstances (if any) would this be appropriate?²⁰

2.2 Scope of work

LEI was retained by Union to provide a high level overview of the funding mechanisms employed in community expansion programs in the provision of natural gas services. LEI's work was not intended to be exhaustive, or to provide specific and detailed recommendations. Specifically, LEI was tasked with providing answers to the following questions:

- What funding mechanisms are adopted for community expansion projects, for example from existing and/or new ratepayers?; and
- What requirements, if any, are placed on incumbent utility customers to help fund expansion projects for new or other utilities?

To provide answers to Union's questions, LEI has reviewed the alternative funding mechanisms adopted across various North American natural gas (New York, North Carolina and Nebraska),

¹⁸ Ontario Energy Board. *Letter – To All Parties in EB-2015-0179 (Union Gas Limited – Community Expansion Application)*. January 20, 2016.

¹⁹ Ontario Energy Board. *Notice: "The Ontario Energy Board is holding a hearing to consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario communities that are currently not served."* February 5, 2015.

²⁰ Ibid.

electricity (Ontario and Alberta) and telecommunication (USA and Canada) markets. Details of LEI's review are presented throughout Sections 3 to 5 of this report.

Specifically, Section 3 provides an understanding of the key economic principles and best practices associated with funding community expansion programs, including a discussion of cost causation principles and funding mechanisms in light of Ontario's public policy mandates. Section 4 documents the treatment of community expansion programs across various North American markets. As part of each case study, LEI highlights the key objectives of the respective expansion programs, adopted funding mechanisms and impacts to utility customers. Finally, Section 5 discusses the implications of the alternative funding mechanisms on customers in Ontario.

2.3 EBO 188 Report on Natural Gas Distribution System Expansion

Ontario natural gas utilities are required to comply with the OEB's guidelines for the expansion of natural gas services as detailed in its report titled "*Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*" (EBO 188).²¹ These guidelines, released in 1998, provide an economic framework for natural gas utilities to evaluate proposed expansion plans in order to ensure no undue increases in rates for existing customers over the longer term. The guideline adopts a portfolio approach (as opposed to assessing projects individually), allowing utilities to combine projects serving high cost-to-serve customers with low cost-to-serve customers. In doing so, the guideline allows a utility to spread part of the costs of expansion across its ratepayers via various cross-subsidies.

Financial limits are placed on the total Investment Portfolio, as well as on individual projects included in the portfolio. Specifically, the Investment Portfolio is to achieve a profitability index greater than 1.0.²² Individual projects within a portfolio (or otherwise) must meet a profitability index of 0.8. Where a project falls below the targeted profitability index, a utility may request a new customer to contribute to the additional costs. Utilities are also required to maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"), updated on a monthly basis. The Rolling Project Portfolio serves as a management tool for the estimation of future impacts of capital expenditures associated with distribution system expansion, including all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects in the portfolio.²³ The OEB requires that the financial feasibility of expansion projects and portfolios be assessed using a standard discounted cash flow analysis including its

²¹ Ontario Energy Board. *Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*. January 30, 1998.

²² Profitability index is calculated as equal to the (present value of operating cash flow plus present value of CCA tax shield) / (present value of capital).

²³ Ontario Energy Board. *Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*. January 30, 1998.

prescribed parameters and common elements for revenue forecasting, capital costs and expense forecasting.

With regards to the monitoring of portfolio performance and short-term rate impacts, utilities are required to include a test year and a historic year financial assessment of the Investment Portfolio and the historic year financial performance of the Rolling Project Portfolio in their rate case filings. This submission is inclusive of estimated and actual investment portfolio net present value, total capital and profitability index, actual expenditures on reinforcement projects, the estimated test year and actual historic rate impact of the investment portfolio, and estimates of the benefit-cost ratio for the investment portfolio using a Societal Cost Test ("SCT"). The guidelines also require ongoing financial and environmental monitoring of utility distribution system expansion project portfolios. In consultation with the Board, utilities shall select projects from their Rolling Project Portfolio and file on an annual basis the cumulative number of customer additions at the end of the third full year, the associated revenues and costs, along with the corresponding third year forecasted performance.²⁴ An annual environmental audit report of a sample set of completed projects is also to be submitted.

Prior to project approval, the expanding utility is required to adhere to the OEB's *"Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities in Ontario"* (1995). In addition, utilities shall apply environmental screening criteria to determine when significant features impacted during the construction and operation of the facilities and obtain where necessary all provincial and local agency permits and licenses.

²⁴ Ibid.

3 Ratemaking regulatory principles and best practice

An understanding of the key economic principles underlying various funding mechanisms enabling the expansion of the natural gas distribution network is essential in setting an appropriate precedent for the funding of expansion projects. It is important to recognize the direct and indirect sources of costs in expanding the network and how to appropriately allocate those costs in order to maximize social welfare. Studying existing public policy mandates within Ontario and weighing the advantages and disadvantages of different sources of cost recovery (for example, from ratepayers or from taxpayers) and methods of cross-subsidization (whether company-specific or jurisdiction-wide) provides insights to economically efficient arrangements for natural gas expansion within Ontario.

3.1 Principles of Cost Causation and its Role in Ratemaking

Cost causation is the principle that costs should be borne by those who are directly responsible for them. This is not only a matter of fairness, but also of sending a price signal to the consumer which encourages efficient resource-using behavior. The cost causation principle is implemented by classifying costs based on defining the service characteristics and using cost-causative allocation methods and factors.

An example of cost-causative classification in electricity includes categorizing fuel costs as energy given the utility's energy costs are related to the energy consumption of customers.²⁵ An example of a cost-causative allocation method is the allocation of fuel among users on the basis of each user's relative share of total kWh because fuel cost is a variable cost primarily caused by total kWh produced.

Cost causation is one of the key principles underlying rate design. Good utility rate designs reflect a consensus between the company, its ratepayers, and its regulators with regards to what is fair and practical. Similarly situated jurisdictions may develop radically different rate designs based on the differing weights policymakers place on various ratemaking objectives. Cost allocation is therefore not easy and can present a challenge to rate makers as it often reflects an arbitrary decision on how to nominate a bundle of costs to a customer within a broader set of parameters, such as:

- ensuring the recovery of a business' total costs;
- providing recovery of an economic margin that reflects the risk adjusted return on capital invested;
- setting rates as much as possible on long run marginal costs of supply; and
- setting rates between the upper (stand-alone costs) and lower (incremental cost) boundaries of defined efficient costs

²⁵ Lowell E. Alt, Jr. *Energy Utility Rate Setting*, 2006.

The textbox below outlines key rate design principles which closely tie-in with the requirements of the OEB in setting efficient rates while promoting the expansion of the natural gas distribution network.²⁶

Rate design principles:

Cost causation and avoidance of cross-subsidies: One of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross subsidies (either between or within customer classes) could be avoided.

Financial stability and fair rate of return: Rates must be set at a level which enables the distribution utility to meet its statutory obligations to serve while earning a fair return and generating sufficient cash flow to support necessary investment.

Incentives compatibility: Rate design should where possible provide appropriate incentives to both the utility and consumer. Depending on the circumstances of the particular jurisdiction, the behavior desired by policymakers may change (i.e. boosting economic growth in Northern and rural Ontario by enabling access to natural gas resource); this in turn may affect the rate design chosen.

Non-discrimination: Similarly situated customers should face similar terms and conditions. Whereas competition in theory will assure that customers with similar tastes and preferences face a similar set of choices, in a regulated environment such an outcome is assured only through enforcing non-discrimination in rate design.

Administrative simplicity and transparency: Rates should be straightforward for customers to understand. Complex rate designs increase costs to consumers, and may result in more time being spent proving that the rate design is fair to all customers.

Source: Bonbright. Principles of Public Utility Rates, Public Utility Reports Inc., Arlington, 1961.

Where possible, adhering to these principles allows for an appropriate allocation of capital investments, operations and maintenance costs directly to individual customers, and indirectly across all customers. In a situation where cost causation can be perfectly identified, cross subsidies (both within and between customer classes) can be avoided. It should also be noted that cost causation is useful as a demand-side management instrument, helping ensure the efficient use of utility services.

There are four main funding mechanisms that may be targeted in the case of expansion of natural gas to rural areas:

²⁶ OEB. *Rate Design Presentation*. June 30, 2014.

- **Natural gas expansion ratepayers:** Here, consumers of the natural gas are responsible for all the costs associated with the expansion of the natural gas distribution network into these areas. This may however, drive the price being paid for natural gas in those areas up to a price where it would be uneconomical for consumption. The high price would also drive down demand, which would cyclically make it more uneconomical to provide affordable natural gas to rural areas.
- **Internal utility cross-subsidization:** In this scenario, expansion costs may be recovered from all customers of a utility by adjusting a utility's general rate base.²⁷ This approach shares the costs between newly acquired customers and existing customers. However, this approach may result in decreased demand for the commodity affecting the utility's ability to recover costs if their consumer base gets smaller. This approach may also seem unfair to existing ratepayers.
- **Jurisdiction-wide cross-subsidization (across all ratepayers):** Expansion costs may be recovered from all ratepayers within a jurisdiction. As this approach spreads the costs across a wider base, it reduces the burden placed on new customers in rural areas. At the same time, this approach distributes the costs of providing natural gas service to rural areas in a similar manner as a tax. However, cross-subsidization across utilities does result in some mismatching of costs and benefits of incumbent utilities, which can cause some reductions in economic efficiency.
- **Taxpayer funded:** Where expansion is seen as providing a social benefit that is shared by the public, levying the cost of expansion through taxes may be a viable option. For example, the LTEP considers the expansion of natural gas to northern and rural areas will prove to be a long-term benefit for the public, in terms of increased competitiveness, greater economic growth, lower greenhouse gas ("GHG") emissions, and greater economic efficiency. Therefore, the cost of this expansion should be borne by all taxpayers.

In selecting among funding mechanisms, consideration should be given to the specific project which funds are to be recovered for. In terms of scale, Union's application for community expansion projects estimates a \$135 million cost to provide access to 18,000 new ratepayers, or approximately 1.2% of its existing 1.4 million ratepayers, and 0.5% of the 3.4 million natural gas ratepayers across the province. Under the context of this expansion, LEI has ranked the above funding mechanisms in Figure 4 based on their alignment with the previously described rate design principles. These rankings may change when applied to other expansion projects or other jurisdictions.

²⁷ Provided these rates remain equal to or above the incremental cost of supply and below the stand alone cost of supply they are considered economically efficient.

Figure 4. LEI ranking of funding mechanisms with respect to Union's application

	Cost causation and avoidance of cross subsidies	Financial stability and fair rate of return	Incentives compatibility	Non-discrimination	Administrative simplicity and transparency
Natural gas expansion ratepayers					
Internal utility cross-subsidization					
Jurisdiction-wide cross-subsidization					
Taxpayer funded					

As shown above, funding expansion costs exclusively through new customers strongly aligns with the principle of cost causation and avoidance of cross subsidies. It is also administratively simple to implement and easy to communicate to customers. However, this method is unfavorable as utilities would only be able to recover its costs, maintain financial stability and earn a fair rate of return by charging exorbitantly high rates. Further, charging high rates to new customers removes the cost saving incentive of switching to natural gas, potentially defeating the purpose of the expansion. This is also discriminatory as this customer group is not able to benefit from the affordable rates available to existing customers.

Internal utility cross-subsidization allows an incumbent utility to recover distribution expansion costs, maintain financial stability and earn a fair rate of return while offering affordable rates to new customers. In doing so, this approach preserves the cost saving incentive of switching to natural gas ensuring the viability of the expansion. Under this regime, discrimination is also reduced as rates are uniform across all utility ratepayers. It is not removed entirely as existing customers pay for the cost of the distribution expansion. Depending on the size of the internal cross-subsidy this mechanism can align with the principle of cost causation. Requiring natural gas ratepayers to pay their own expansion costs, or allowing for internal cross-subsidization, may limit the incentives for new entry or expansion of other distributors into certain areas. Further as the total new expansion customers securing access to the network is relatively small compared to the existing ratepayer base these mechanisms are considered administratively simpler to implement.

Much like internal utility cross-subsidization, jurisdiction-wide cross-subsidization and taxpayer funded mechanisms enable the utility conducting the expansion project to recover the

costs, maintain financial stability and earn a fair rate of return, preserve the cost saving incentive of switching to natural gas and reduce discrimination. These approaches minimize discrimination as expansion costs are borne by all ratepayers or taxpayers. In this instance adoption of a jurisdiction wide cross subsidy or new tax may not be considered administratively simple or transparent, in particular where legislative changes are required. These approaches are least aligned with the principle of cost causation and are indicative of the overriding importance of ensuring affordability for all natural gas customers.

Section 3.2 addresses existing and relevant public policy mandates within Ontario that provides some background on the regulatory environment and direction behind this expansion project. Additional information on the advantages and disadvantages of pursuing any of the four funding mechanisms mentioned above is detailed in Section 3.3.

3.2 Public Policy Mandates in Ontario

As outlined in the 2013 LTEP, Ontario wants to make sure communities have access to natural gas to take advantage of the changes in North American natural gas markets, particularly the low prices of the commodity. This is also driven by the fact that natural gas heating is significantly less expensive than that provided by electricity, propane or heating oil.

The expansion of natural gas distribution networks also aligns with Ontario's environmental and carbon reduction goals. Ontario has a goal to reduce greenhouse gas pollution by 15% below 1990 levels by 2020, and 80% below 1990 levels by 2050.²⁸ In recent years the Ontario government has initiated policy mandates which have expanded renewable energy production, encouraged energy conservation, created green jobs and closed (or converted to biomass) coal-fired electricity plants. Ontario now intends to limit its main sources of greenhouse gas pollution through implementation of a cap and trade program linked with Québec and California.²⁹

Further to the environmental benefits for the Province, additional economic benefits also result from expansion of the natural gas distribution network, including cheaper heating and energy rates for rural communities, increases in the number of construction jobs during the construction period and municipal tax revenues. The environmental and economic benefits that would result from the gas access expansion would be wide-spread and applicable to all residents of Ontario consistent with the definition of a public good as detailed in the textbox below.

²⁸ In order to help achieve its long-term targets, the province has also committed to a new mid-term target to reduce emissions by 37% below 1990 levels by 2030.

²⁹ Government of Ontario. *News Release - Cap and Trade System to Limit Greenhouse Gas Pollution in Ontario*. April 13, 2015.

Public Goods and Free Riders

A public good as defined by economic theory, is a good that, once produced, can be consumed by an additional consumer at no additional cost. Public goods are goods that can be consumed by everybody in a society or nobody at all. They cannot or will not be produced for individual profit, since it is difficult to get people to pay for its large beneficial externalities. It is helpful to think about a public good as one with a large positive externality. Public goods are both *non-excludable* and *non-rivalrous* in that non-payers cannot be effectively excluded from use and where use by one user does not reduce availability to others. Common examples of public goods include defense, public fireworks, lighthouses, clean air and other environmental goods, and information goods, such as software development, authorship and invention. Public goods often create free-rider problems, in which people not paying for the good may continue to access it, which in turn results in the goods being overused and ultimately under-produced.

In order to minimize the social inefficiency of free-riders, it is important to identify a public good appropriately and either put in place barriers to access (if possible) or ensure a mechanism by which those individuals that access or have the potential to access it are also bearing the cost of the public good.

Source: A Theory of Public Goods by Randall G. Holcombe.

3.3 Ratepayers vs. Taxpayer Support

As identified in Section 3.1, there are four main sources for financial support of the natural gas community expansion project including (i) natural gas expansion ratepayers, (ii) internal utility cross-subsidization, (iii) jurisdiction-wide cross-subsidization, and (iv) taxpayer funding. It is important to study the community expansion project as a whole, taking into account both the direct (improved access to natural gas) and indirect (positive environmental and economic) impacts. These impacts will help justify the rationale behind the option that is chosen as a funding mechanism for the project.

3.3.1 Natural gas expansion ratepayers (no cross-subsidization)

Union Gas has estimated an annual revenue requirement ranging from approximately \$3.9 million in 2016 to \$11.4 million in 2018 and a capital investment of \$135 million across all 29 community expansion projects.³⁰ One option to meet this requirement is to have rates set for the rural customers that accounts for the large upfront investment. This in turn would have the effect of driving the price being paid for natural gas by rural customers significantly higher than the average rates paid in more densely populated urban and sub-urban areas.

³⁰ Union Gas Limited. Application EB-2015-0179 - Union Gas Limited ("Union") - Community Expansion - Evidence Update. December 14, 2015.

So long as the price of natural gas is higher than available alternatives, the number of consumers switching to natural gas from lower-cost fuels would be limited. This would decrease the customer base from which a gas utility may recover its cost of expansion from, and would drive further rate increases, resulting in cyclical diseconomies of scale and potentially stranded assets

Expensive natural gas in rural areas would also not align with Ontario's LTEP, of which one of the goals was to provide affordable, clean sources of energy to rural communities. One of the greatest advantages of access to natural gas is that it is cheaper than oil, propane and electricity when used for heating at about half the cost.³¹ This is expected to free up a significant amount of capital in these communities by lowering on-farm energy costs and attracting new businesses.³² This can be re-invested to further develop the community and boost economic growth. If rates for natural gas are set at a high price, it loses its low-price advantage and diminishes the associated benefits.

3.3.2 Internal utility cross-subsidization

Cross-subsidization in this context amounts to the sharing of costs between newly serviced rural customers and existing utility ratepayers. By spreading the rate increase across its customer base, a utility can minimize the cost impact to any one customer, while ensuring rates are fair and equitable, and earning an appropriate return on its investment. Further, through expansion of its own natural gas network, a utility may benefit from the economies of scale relative to a new entrant providing a similar service.

However, as pointed out by Multiple Intervenors during New York's gas distribution expansion case (detailed in Section 4.1.1), cost recovery is based on demand, and unjustified rate increases to consumers that are not directly benefiting from this expansion may result in consumers choosing alternate fuel sources and/or different providers.³³ Additionally, as noted in Section 3.1, cost allocation presents a challenge to rate makers as it often reflects an arbitrary decision on how to nominate a bundle of costs to a customer (or customer group). This can result in an administrative burden to regulators or the utility, in particular in defining what is fair and equitable to ratepayers.

In its application, Union proposed to cross-subsidize rural gas consumers' rates by increasing its existing gas consumers' rates between \$0.71 and \$4.80 per annum.³⁴ Union is one of the two

³¹ Ontario Federation of Agriculture. *Issue Update: Affordable natural gas across rural Ontario*. 2015.

³² Ibid.

³³ Multiple Intervenors. *Intervenor Comments on Case 12-G-0297 - Proceeding on Motion of the Commission To Examine Policies Regarding the Expansion of Natural Gas Service*. March 12, 2013.

³⁴ Union Gas Limited. Application EB-2015-0179 – Union Gas Limited (“Union”) – Community Expansion – Evidence Update. December 14, 2015.

major gas distributors in Ontario with approximately 1.4 million residential, commercial and industrial customers.³⁵ This customer base provides the opportunity to minimize the overall cost impacts to a single customer or customer group.

Internal cross-subsidization has been applied in other jurisdictions including Ohio, Nebraska and North Carolina. In 2014, Ohio passed a bill permitting natural gas companies to apply infrastructure development riders to recover costs of gas distribution expansion projects that could be applied to all customers of the natural gas utility. In 2012, Nebraska passed legislation allowing utilities to apply a rural infrastructure surcharge to customers within an expansion area and to a broader set of utility customers as well. In North Carolina, the 1991 Natural Gas Expansion/Cost Act specified that distribution expansion surcharges apply to all customers of the Local Distribution Company (“LDC”) that was carrying out the expansion.

3.3.3 Jurisdiction-wide cross-subsidization

A third mechanism of funding expansion projects would be to introduce a jurisdiction-wide cross-subsidy. In that case, the cost of expanding the network is spread across all ratepayers as opposed to the incumbent utility only, resulting in lower incremental charges to all ratepayers. Subject to the service in question and the wider policy objectives of government, a jurisdiction may be defined as municipal, state/provisional or federal. For example provisional cross-subsidies have been adopted in the provision of electricity services to rural communities in Alberta and Ontario, while both Canada and the US provide for federal cross-subsidies in the provision of universal telecommunication services. Case studies describing these funding mechanisms are provided in section 4.2 and 4.3 respectively.

Adoption of jurisdiction-wide cross-subsidization may be attributed to the view that the provision of natural gas services to rural communities is identified as a public good and as such is more suited to allocation over as broad a base as possible. This is comparable to the application of a broad base tax regime (as discussed in Section 3.3.4). Under this approach, LEI notes that other utilities may be adversely impacted by increased costs and possibly lower demand, without enjoying the benefits of an increased customer base.

3.3.4 Taxpayer funded

The provision of natural gas services can also be supported through a broad-based funding mechanism, such as the introduction of a tax (or rate increase applicable to all ratepayers).

A challenge in implementing a tax is the ability to balance both the social and economic objectives, while minimizing the negative welfare effects associated with an increase in taxpayer costs. For a given distributional outcome, an objective tax system should:

- minimize the negative effects of the tax system on welfare and economic efficiency;

³⁵ Union Gas. *Union Gas at a Glance*. Accessed February 29, 2016. <<https://www.uniongas.com/about-us/at-a-glance>>

- provide for low administration and compliance costs;
- ensure fairness of procedure and avoidance of discrimination, consistent with legitimate expectations; and
- be as transparent and easily understood as possible.³⁶

Taxes are used to impact behavior by altering the incentives for certain sorts of behavior. A tax system should not only limit negative effects on efficiency but also promote economic welfare by dealing with externalities as, and when, they arise.

Taxes may also be classified as broad-based or narrow-based. A broad-based tax is one that taxes most, if not or all, of a population, and it can thus recover costs by charging a relatively low per capita tax. A narrow-based tax regime targets a specific sub-set of the population, for example the introduction of a carbon tax on high emitting industries.

As discussed earlier, the expansion of natural gas services to rural communities creates a positive externality for consumers and the broader community in general, in the form of reduced energy or heating costs, job creation, incremental tax revenue and contribution to greenhouse gas emission reduction targets. These benefits may be considered a public good, and therefore enjoyed by all taxpayers. Where these benefits outweigh the associated costs of expansion of the network, a broad-based tax regime may be a viable funding option for the delivery of the expansion, for example through the creation of a government or not-for-profit administered fund or grants.

This broad-based approach minimizes the distortionary effects on any one consumer, while mitigating the problem of free-riders, as almost all individuals are contributing toward the production of the public good. Using a broader base also makes it more likely that the tax system will treat all economic activities the same, which helps ensure that the tax system will not discriminate in favor of some taxpayers and against others.

³⁶ Institute for Fiscal Studies. *Tax by design*. September 13, 2011.

4 Rate setting treatment for community expansion programs

As the following case studies will demonstrate, community expansion in the natural gas, electricity and telecommunications sectors is nearly always subsidized either by the government, existing ratepayers of the incumbent utility or a combination of the two methods. Our research shows that cross-subsidization for rural expansion in each case only required ratepayers of an existing company to bear a new entrant's expansion costs in the context of jurisdiction-wide arrangements in which all companies participated. If charges are passed on to ratepayers they are done so in a uniform method whereby all customers in the area are charged equally. Where the positive externalities of reduced emissions from adoption of gas in rural areas are broadly shared, natural gas access expansion takes on characteristics of a public good, and is often treated accordingly.

4.1 Natural gas

The natural gas industry has faced similar issues related to infrastructure development and service expansion in traditionally uneconomic areas. This section provides an overview of the solutions and mechanisms used to improve the viability of these projects, whether cross-subsidization was implemented and how the apportioning of these costs was handled, focusing specifically on North America.

4.1.1 New York - Internal utility cross-subsidization

In New York, the New York Public Service Commission ("NYPSC") interprets requirements as prescribed under Public Service Law Section 68 to require expansion projects be economic for ratepayers.³⁷ In accordance with NYSPC's 1998 "Policy for Rate Treatment of Gas Service Expansion into New Franchise Areas, Statement of Policy Regarding Rate Treatment to be Afforded to the Expansion of Gas Service Into New Franchise Areas", projects are to be assessed over a five year development period. Each project is required to earn the utility's permitted rate of return within the expanded area by the end of the five year period. The NYPSC in its role as the utility regulator has jurisdiction to approve expansion projects on a case by case basis where the proposed project differs from the standard requirements that exist under Public Service Law

New York -- general facts

Population: 19.7 million

GDP: \$1,404.5 billion

Natural Gas Landscape

Total Production: 6.8 billion m³

Total Consumption: 39.4 billion m³

Total gas distribution pipeline: 139,314 km

Residential Natural Gas Price: \$0.13 per \$10 billion of GDP

Percentage of households using natural gas for heating: 56.4%

Source: US Energy Information Administration and US Department of Transportation Pipeline and Hazardous Materials

³⁷ New York Public Service Commission. *Case 12-G-0499 Petition of New York State Electric & Gas Corporation to Amend its Certificate of Public Convenience and Necessity and to Exercise a Gas Franchise in the Town of Plattsburgh, Clinton County, New York*. July 29, 2014.

Section 68.

Traditionally, if utilities in New York state wish to expand natural gas service to serve a new area they are entitled to collect a surcharge from all customers in the new area for a five-year period. The surcharge is granted if it is projected that the rate of return at the end of five-year period will be less than the utility's permitted rate of return. Any surcharge collected is restricted to only that which is required in order to recover any shortfall that is anticipated to be outstanding at the end of the five year period.³⁸

NYPSC deviated from this policy when they approved an application for an expansion project from New York State Electric & Gas Corporation's ("NYSEG") that sought a development period of ten years. As the proceeding example will demonstrate, the NYPSC approved the application to extend the development period because it desired to minimize the surcharge amount charged to ratepayers, by spreading the cost recovery over a longer term. This method of implementation of cross-subsidization minimizes distortionary effects as the elasticity of demand for natural gas would be relatively low when the price change was small. The approach also demonstrates the key rate design principle of financial stability and fair rate of return, because the utility was able to meet its statutory obligations and earn a fair return on the expansion by minimizing the surcharge. In addition, the utility was able to efficiently allocate the costs over its customer base (both existing and new) in a manner that sought to minimize any aggressive increase to their service costs that may decrease their demand. In this case, there was no research found to suggest that cross-subsidization across utilities is allowed.

On November 30, 2012, the NYPSC issued an order instituting a proceeding to establish further examination of policies regarding the expansion of natural gas service.³⁹ The order highlighted that "33% out of the roughly 3 million New York households that currently heat with fuels other than natural gas, live within an existing natural gas franchise area."⁴⁰ Furthermore the NYPSC acknowledged that the current framework for natural gas expansion would need to be refined for the benefits of natural gas to be realized by more New Yorkers. They set out to engage LDCs and intervenors in an effort to establish a standardized process that would allow greater expansion opportunities in remote areas. Feedback was received from Multiple Intervenors who expressed concern, and advised that cost recovery should be based on demand, and that unjustified rate increases to consumers that are not directly benefiting from this expansion may

³⁸ New York Public Service Commission. *Case 89-G-078, Policy for Rate Treatment of Gas Service Expansion into New Franchise Areas, Statement of Policy Regarding Rate Treatment to be Afforded to the Expansion of Gas Service Into New Franchise Areas*. December 11, 1989.

³⁹ The NYPSC highlighted the benefits of natural gas as an alternative fossil fuel due to its relative environmental benefits and associated decreasing cost compared to other fossil fuels. Further NYPSC noted that amidst these benefits its use was not in widespread use throughout the State.

⁴⁰ New York State Public Service Commission. *Case 12-G-0297 Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service*. November 30, 2012.

result in them looking to alternate fuel sources and/or different providers.⁴¹ Though NYPSC's effort did not result in any defined changes or concluding remarks, it is likely that the feedback collected may have influenced the outcomes of the following case that was brought before them on November 1, 2012.

The application was made by NYSEG who petitioned the NYPSC seeking to expand their service offering to the remaining areas in the Town of Plattsburgh.⁴² The proceeding went on for two years before a decision was reached on July 29, 2014 that would allow NYSEG to expand to the remaining areas of Plattsburgh and recover the costs of expansion over a ten-year development period as opposed to the traditional five. In their decision the NYPSC commented that *"a ten-year development period is appropriate in this case given the current price of natural gas as compared to alternative fuels and the density of potential customers in the economic footprint. Further, a ten-year period will reduce monthly billing impacts for customers."*⁴³ NYSEG would recover the costs of expansion from all connecting customers in the approved area (both existing and new customers) using a uniform surcharge of 9.95 cents per cubic meter of natural gas.

The decision meant that residents in the natural gas expansion area who switched to natural gas from fuel oil for space and water heating would realize annual projected cost savings of \$899. If a resident switched from electric space and water heating to natural gas, savings were estimated to be even greater, at \$1,804 per year.⁴⁴ This demonstrates material cost savings and overall reduction in cost of living for residents in the expanded area. The benefits realized from natural gas distribution network expansion in this case included cheaper energy rates for rural communities, potential for increased business and professional opportunities and a cleaner environment.

4.1.2 North Carolina - Government funding

North Carolina recognizes the importance of natural gas access and has identified it as a public good where it is viewed as a social benefit that is shared by all. Costs associated with delivering natural gas to uneconomic areas are levied through taxes. This example satisfies the key rate design principle of appropriate identification of cost causation because the cost is borne by the public in order to achieve an overall environmental and economic benefit for the state of North Carolina. The state has enacted legislation that mandates both the monitoring and funding of natural gas expansion. As described below, the State has been active in promoting natural gas

⁴¹ Multiple Intervenors. Intervenor Comments on Case 12-G-0297 - Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service. March 12, 2013.

⁴² Ibid.

⁴³ New York State Public Service Commission. *Case 12-G-0499- Petition of New York State Electric & Gas Corporation to Amend its Certificate of Public Convenience and Necessity and to Exercise a Gas Franchise in the Town of Plattsburgh, Clinton County, New York.* July 29, 2014.

⁴⁴ NYSEG. Energy Cost and Savings Analysis - Town of Plattsburgh. 2015.

access as a public good as evidenced by their review and refinement of funding mechanisms over the years. In this example, the majority of funding comes from taxpayers but a small amount of cross-subsidization occurs whereby existing interstate gas pipelines are required to put rebates received from US Federal Energy Regulatory Commission (“FERC”) decisions towards an expansion fund.

Expansion of the natural gas network in North Carolina has been supported, prioritized, and funded by the state since 1989. Here, the North Carolina Utilities Commission (“NCUC”) plays an instrumental role in monitoring expansion and funding decisions for proposed expansion projects. Through the Natural Gas Planning Act, 1989⁴⁵, the Natural Gas Expansion/Cost Act, 1991⁴⁶ and the Clean Water and Natural Gas Critical Needs Bond Act, 1998⁴⁷, North Carolina ensures expansion projects are well supported and funded. Each act plays a different role in determining eligibility of projects for funding and determination of the source of the funding itself.

Through the Natural Gas Planning Act (1989) the NCUC is able to monitor the need for and planning of expansions through reports submitted by LDC’s. The act requires each LDC to publish and submit a biannual report to the NCUC that includes *“its plans for providing natural gas service in its franchise territory in which natural gas service is not available.”*⁴⁸ The NCUC is thus able to make well informed funding decisions since they are regularly updated on the demand for expansion.

North Carolina -- general facts

Population: 9.9 million

GDP: \$483.1 billion

Natural Gas Landscape

Total Production: N/A

Total Consumption: 12.6 billion m³

Total gas distribution pipeline: 89,389 km

Residential Natural Gas Price: \$0.35 per \$10 billion of GDP

Percentage of households using natural gas for heating: 24.6%

Source: US Energy Information Administration and US Department of Transportation Pipeline and Hazardous Materials

⁴⁵ North Carolina Legislature. House. *An Act to Require Natural Gas Local Distribution Companies to Report Plans for Providing Natural Gas Service in Unserved Areas to the Utilities Commission to Report on Expansion of Natural Gas Service to the Joint Legislative Utility Review Committee.* (HB 970) 1989 Session. 31 March 1989.

⁴⁶ North Carolina Legislature. House. *An Act to Facilitate the Construction of Facilities in and the Extension of Natural Gas Service To Unserved Areas and to Revise the Procedures for Gas Cost Adjustments for Natural Gas Local Distribution Companies.* (HB 1039) 1991 Session. (8 July 1991) General Assembly of North Carolina.

⁴⁷ North Carolina Legislature. House. *An Act to Authorize the Issuance of General Obligation Bonds of the State, Subject to a Vote of the Qualified Voters of Government Units for Water Supply Systems, Wastewater Collection Systems, Wastewater Treatment Works, and Water Conservation and Water Reuse Projects and (2) For Grants, Loans, or Other Financing to Public or Private Entities for Construction of Natural Gas Facilities.* (SB 1354). September 9, 1998.

⁴⁸ General Assembly of North Carolina. *Natural Gas Planning Act.* March 31, 1989.

The Natural Gas Expansion/Cost Act (1991) attempted to enable cross-subsidization by allowing each LDC (through approval by the NCUC) to create their own fund specifically for expansion projects. The fund could be raised by levying surcharges on all existing ratepayers of that LDC and/or by having interstate natural gas pipelines and other entities subject to rate regulation by FERC pass on rebates they received as result of a FERC decision.⁴⁹ LDC's have never used the cross-subsidization approach of applying surcharges to all customers, and with the unpredictable nature and frequency of rebates resulting from FERC decisions the North Carolina General Assembly determined that the Natural Gas Expansion/Cost Act of 1991 on its own was not facilitating the level of expansion that they had envisioned. The Act refers to natural gas service as one "*that is necessary and in the public interest*"⁵⁰ and felt that a more reliable funding mechanism was needed. The remedy was sought with the release of the Clean Water and Natural Gas Critical Needs Bond Act of 1998 which authorized the release of "\$200 million to provide grants, loans, or other financing to natural gas local distribution companies, persons seeking natural gas distribution franchises, State or local government agencies, or other entities for construction of natural gas facilities."⁵¹

The NCUC has discretion to administer both funds collected under the Natural Gas Expansion/Cost Act, as well as the bonds granted by the government and does so only for the portion of an expansion project that the NCUC determines is "infeasible". The NCUC defines a project as infeasible when they employ a discount rate equal to the utility's cost of capital and find that the project results in a negative net present value.

All three acts together promote natural gas access as a public good and create a legislative backbone that acts an effective system for monitoring, approving and funding expansion of the natural gas network across the state. Free ridership to the public good is mitigated as the bonds are funded by taxpayers and cross-subsidization is minimal. Funding is administered by the NCUC, who also has the responsibility of reviewing and reporting on the bi-annual natural gas expansion reports from all LDC's.

As a result of the funding mechanisms in North Carolina,"*all but four counties have natural gas service available. The remaining four unserved counties, Alleghany, Cherokee, Clay, and Graham, are located in the mountainous western portion of the State and are all presently unfranchised.*"⁵²

⁴⁹ The original Act had an additional funding source from an expansion surcharge on all of the LDC's existing customer base but due to changes in U.S. federal legislation, this practice has become obsolete.

⁵⁰ General Assembly of North Carolina. *The Clean Water and Natural Gas Critical Needs Bond Act*. 1998.

⁵¹ *Ibid.*

⁵² North Carolina Utilities Commission. *Report to the Joint Legislative Commission On Governmental Operations - Analysis and Summary of Expansion Plans of North Carolina Natural Gas Utilities and the Status of Natural Gas Service in North Carolina*. April 24, 2012.

In Ontario funding options available to natural gas distributors are being led by the Ministry of Economic Development, Employment and Infrastructure with support from the Ministry of Energy and the Ministry of Agriculture and Rural Affairs.⁵³ Announced funding includes, Natural Gas Access Loan, which will provide up to \$200 million over two years to help communities partner with utilities to extend access to natural gas supplies and a \$30-million Natural Gas Economic Development Grant to accelerate projects with clear economic development potential.^{54,55} Though these funding mechanisms exist, unlike the NCPC, there is currently no legislation which establishes the OEB as the administrator of them.

4.1.3 Nebraska – Internal utility cross-subsidization

Nebraska is an example of a state that has instituted internal utility cross-subsidization in an effort to achieve financial stability and a fair rate of return for utilities. A utility must first employ the principle of direct cost causation to determine if ratepayers in the desired new expansion area can support, through a surcharge, the costs of expansion. It is then up to the discretion of the Nebraska Public Service Commission (“NPSC”) to determine if the resulting rates are commercially unreasonable. If they are, the utility is allowed to recover the remaining uneconomic portion from ratepayers in areas outside of the new expansion area. This approach demonstrates how a combination of cost causation and cross subsidization may be used to achieve gas expansions.

Nebraska -- general facts

Population: 1.9 million
GDP: \$112.2 billion

Natural Gas Landscape

Total Production: 11.3 million m³
Total Consumption: 5 billion m³
Total gas distribution pipeline: 33,540 km
Percentage of households using natural gas for heating: 66%

Source: US Energy Information Administration and US Department of Transportation Pipeline and Hazardous Materials

In 2012, Nebraska passed legislation (Bill 1115)⁵⁶ allowing utilities to apply a Rural Infrastructure Surcharge (“RIS”) to customers within an expansion area and, if necessary, apply the surcharge to a broader set of utility customers.⁵⁷ The filing must include descriptions and attributes of any proposed expansion project, including the capacity and the potential to

⁵³ Ministry of Economic Development, Employment and Infrastructure. *Ontario Expanding Natural Gas Service to More Communities*. April 24, 2015.

⁵⁴ Wynn, K. 2014 Mandate letter: Economic Development, Employment and Infrastructure. Sept 25, 2014.

⁵⁵ Ibid.

⁵⁶ Nebraska Legislature. *Nebraska Revised Statute Chapter 66 Section 1868*. Laws 2012, LB1115, § 10. April 2012.

⁵⁷ LEI note the authority of the OEB to approve cross-subsidies between utilities is currently under debate as part of Generic Proceeding EB-2016-004.

enhance demand, as well as details surrounding the proposed rate increases for customers and source of financing (city funds, funds from the Local Option Municipal Economic Development Act, and/or contributions from direct customers which may include state or federal grants or loans).⁵⁸

Under this legislation a utility may apply to adjust rates to appropriately recover the costs associated with the rural infrastructure development. Bill 1115 also states that a utility may undertake rural infrastructure development necessary to supply unserved or underserved areas in or adjacent to areas presently served by the jurisdictional utility and not served by another jurisdictional utility.⁵⁹ This effectively precludes a new entrant from supplying an area if it is not already the incumbent utility in that area or the adjacent area, and in effect prevents cross-subsidization of rural expansion between utilities.

The RIS must first be allocated to customers who will be directly receiving the service and if the rates that result are uneconomic or commercially unreasonable (which is subject to the NPSC's discretion). The utility may cross-subsidize the expansion by recovering costs from their general system customers in the same city for which they already have jurisdiction until costs are fully recovered.⁶⁰

NPSC may engage in a proceeding (a maximum of once per year) to review the surcharge to determine if it reflects the *"actual costs of the rural infrastructure development and to reconcile any amounts collected from ratepayers with actual costs incurred by the jurisdictional utility."*⁶¹ Any refunds resulting from the NPSC's investigation are returned to ratepayers as a credit on their bills.

4.2 Electricity

Similar to the natural gas industry, the electricity industry has had its share of obstacles related to servicing traditionally uneconomic areas. This section provides an overview of the solutions and mechanisms used in Ontario and Alberta to improve the viability of providing electricity service to rural areas. The following two examples discuss whether cross-subsidization was implemented, and how the apportioning of these costs was handled.

4.2.1 Ontario - Rural Electricity Rate Protection Program

This example represents cross-subsidization on a jurisdiction-wide scale which socializes costs of providing rural electricity service to areas all ratepayers and functions similar to a tax.

⁵⁸ Ibid.

⁵⁹ Legislative Assembly of Nebraska. *Legislative Bill 1115 Section 4*. April 2012.

⁶⁰ Nebraska Committee on Urban Affairs. *Committee Statement on LB1115*. February 7, 2012.

⁶¹ Ibid.

Through this approach instituted by the OEB and facilitated by the Independent Electricity System Operator (“IESO”), all ratepayers cross-subsidize the cost to service rural ratepayers. This helps make electricity service to uneconomic areas a possibility and drives economic growth in Ontario by ensuring more widespread electricity access.

Ontario’s electricity market provides for a rural service subsidy through the Rural or Remote Electricity Rate Protection (“RRRP”) program which “is designed to provide financial assistance to eligible customers located in rural or remote areas

where the costs of providing electricity service to these customers greatly exceeds the costs of providing electricity to customers located elsewhere in the province of Ontario.”⁶² In effect, the RRRP program provides a method to subsidize rural distributors’ cost of serving remote communities, costs that would otherwise be passed through to their customers.

The IESO has established eligibility criteria which determine which ratepayers are eligible for protection under the RRRP. Specifically, these customers must be:

- Rural area consumers who were previously eligible for discounted rates under Ontario Hydro and who would still be paying those rates had section 28 of Schedule E of the Energy Competition Act, 1998 not taken effect; or
- Residential consumers of the following distributors; Attawapiskat, Fort Albany, or Kaschechewan, provided that Ontario Hydro distributed electricity in the area before December 16, 1997;
- Consumers who are not connected to the IESO controlled grid and who are customers of Hydro One Remote Communities Inc.; or
- Residential-rate consumers pursuant to Ontario Regulation 445/07; or
- Consumers served in an area by a distributor where the area is not less than 10,000 square kilometers in size and the average customer density for the distributor is less than seven customers per kilometer of distribution line.⁶³

The OEB is responsible for determining what total funding is required under the RRRP program to assist rural distributors. Each year the IESO calculates the RRRP amount that eligible consumers are entitled to receive by providing to the OEB a forecast of the number of kilowatt hours of electricity that will be withdrawn from the IESO-controlled grid, by

Ontario -- general facts

Population: 8.3 million
GDP: \$721 billion

Electricity Landscape

Installed Capacity: 35,221 MW
Consumers served: 4.9 million
Total Annual Energy Consumed: 137 TWh
Transmission Lines: 30,000 km

Source: Ontario Ministry of Finance and IESO

⁶² Ontario Energy Board. *EB-2014-0347 Decisions with Reasons and Rate Order*. December 19, 2014.

⁶³ Ontario Energy Board Act 1998. Ontario Regulation 442/01 Rural or Remote Electricity Rate Protection.

consumers in Ontario during the next calendar year.⁶⁴ The OEB uses the IESO's forecast to set the aggregate benefit amount that the IESO will be responsible for collecting.

It is important to note that there is no IESO equivalent facilitating the operation of the natural gas network in Ontario. Adopting a program similar to the RRRP for natural gas may be considered administratively burdensome given the costs associated with establishing an independent entity required to implement, as well as facilitate, a similar framework.

4.2.2 Alberta - Rural Electric Program

The Rural Electric Program ("REP") in Alberta is an example of a mix of cross-subsidization of rural rate payers and taxpayer funding. In this case there is a direct matching of costs and benefits incurred as the source of funding for grants comes from rural distributors.

The Alberta Ministry of Agriculture and Forestry also allocates a portion of their budget to rural development programs. In this unique example, there is a blend of appropriate application of cost causation principles and a taxpayer funding mechanism working together to make rural electricity expansion an economic endeavor.

Alberta -- general facts

Population: 4.1 million
GDP: \$375 billion

Electricity Landscape

Installed Capacity: 15,173 MW
Consumers served: 1.7 million
Total Annual Energy Consumed: 82 TWh
Transmission Lines: 26,000 km

Source: Statistics Canada & Energy Alberta

In 1947 Alberta began its REP in order to help reduce the high costs associated servicing customers located in rural areas. The program was founded to provide farmers with essential electricity service under the theory that it will promote expansion and diversification for Alberta's economy, specifically to enhance the agricultural sector of the Alberta economy. This is recognized as a social benefit that is shared by all Albertans.

The REP collects funds from the Rural Electrification Association ("REA") and reallocates them in the form of grants back to new rural ratepayers. Alberta's REP differs from that of Ontario's in that it is not a facilitated automatic flow-through process of collected and dispersed funds; instead grants are only paid out to successful applicants.

A rural customer must apply for grant assistance under the program and is only eligible for assistance if they occupy, own, or rent a property that is considered a farm. Evidence of possession of an Alberta Farm Fuel Benefit ("AFFB") number is required to demonstrate eligibility. The application requires applicants to work with their local utility or REA to determine the associated costs of service. Applicants can simultaneously apply for an AFFB when applying for assistance under the REP. The program intends to allow rural customers to

⁶⁴ Ibid.

pay rates that are more in line with urban area ratepayers who benefit from provincially sponsored reduced power rates and lower connection costs.

The grants paid out to successful applicants are funded by the Alberta Federation of Rural Electrification Associations (“AFREA”). AFREA’s mission “*is to Represent and Support Rural Electrification Associations by responding to Legislative, Regulatory, and Operational needs for a Sustainable Future.*”⁶⁵ It is a not-for-profit association which operates under the Alberta Rural Utilities Act and is funded by its members whom comprise of primarily REA who own electric distribution systems and supply electricity to rural regions of Alberta.

The AFREA assesses applications against their specified requirements, and subject to availability of funds, approves the grants. To determine which costs are eligible for grant assistance the AFREA uses the following general criteria:

- a) Grants will be based on the most practical and economical route, a standard 25kVA transformer for an overhead service and 50 kVA on an underground service;
- b) Irrigation, grain dryer and three phase services may include the additional transformer capacity in calculating the grant;
- c) Where a service must be constructed in a more expensive manner as a result of federal, provincial or municipal regulation or law, the additional cost may be eligible for a grant (up to the maximum grant amount); and
- d) One transformer equals one service equals one grant.⁶⁶

There is no limit on the number of grants that an eligible farmer may receive. The maximum amount per grant is \$5,250.⁶⁷

Grants are based on cost of service which reflects the most practical and economical route using standard equipment. The AFREA also consider whether the service must be constructed in a more expensive manner as a result of regulation or law. This allows the AFREA to determine the final basic system capital cost to be used to calculate total grant eligibility.⁶⁸

The grant eligibility is then calculated as follows:

- a) Where an electric utility or an REA invest in the new service and the investment exceeds the cost of the service, no grant will be paid.

⁶⁵ Alberta Federation of Rural Electrification Associations. *AFREA Mission*. Last Accessed: March 2nd, 2015. <<http://www.afrea.ab.ca/>>

⁶⁶ Alberta Federation of Electrification Associations. *Rural Electric Program Guidelines*. December 2014.

⁶⁷ Ibid.

⁶⁸ Ibid.

- b) If the investment by the electric utility or REA does not exceed the cost of the service, grant eligibility will be the lesser of the grant eligibility prior to the investment or the amount that the customer is responsible to pay to the electric utility or REA.⁶⁹

4.3 Telecommunications

The telecommunications industry has faced similar issues to that of the natural gas and electricity sectors. This section provides an overview of the solutions and mechanisms used to improve the viability of these projects, whether cross-subsidization took place and how the apportioning of these costs was handled, focusing specifically on the US and Canada.

4.3.1 United States – Jurisdiction-wide cross-subsidization

Within the US, government policy is built on the principle that a baseline level of telecommunications is a universal service and should be available to all Americans at reasonable charges. In the Communications Act of 1934, universal service is defined as “*an evolving level of telecommunications services that the Commission shall establish periodically under this section, taking into account advances in telecommunications and information technologies and services.*”⁷⁰ Under the Communications Act, the advancement of universal service is based on the following principles:



Population: 318.9 million
GDP: \$16.77 trillion USD
GDP per capita: \$53,041 USD
Households: 115.6 million
Telecom coverage: 95.2%

Source: United States Census Bureau, World Bank

- **Quality and rates** – quality services should be available at just, reasonable, and affordable rates;
- **Access to advanced services** – access to advanced telecommunications and information services should be provided in all regions of the country;
- **Access in rural and high cost areas** – consumers in all regions of the country, including low-income consumers and those in rural, insular and high cost areas should have access to telecommunication and information services at rates comparable to rates charged in urban areas;
- **Equitable and nondiscriminatory contributions** – all providers of telecommunication services should make an equitable and nondiscriminatory contribution to the preservation and advancement of universal service;

⁶⁹ Ibid.

⁷⁰ Federal Communications Commission. *Communications Act of 1934 – Amended by Telecommunications Act of 1996.* <<https://transition.fcc.gov/Reports/1934new.pdf>>.

- *Specific and predictable support mechanisms* – there should be specific, predictable and sufficient Federal and State mechanisms to preserve and advance universal service; and
- *Access to advanced telecommunications services for schools, libraries and health care providers* – telecommunications carriers should provide advanced services to schools and libraries at rates lower than the amounts charged for similar services to other parties; carriers should provide services to rural health care providers at rates that are reasonably comparable to rates for similar services in urban areas.⁷¹

Support for the goals of universal service is provided through the Universal Service Fund (“USF”) following a directive from Congress. Telecommunications companies providing international and interstate service are required to make annual contributions to the fund based on a percentage of earned revenue.⁷² Although not required by law, many carriers pass on their contribution costs to end consumers. These funds are collected and disbursed by the Universal Service Administrative Company (“USAC”), an independent non-for-profit corporation created by the Federal Communications Commission (“FCC”). USAC allocates universal service funds across the following programs:

- *High Cost Program* – provides support for telecommunications companies that serve consumers in hard-to-serve, rural areas at rates comparable to urban rates;
- *Lifeline Program* – provides support for telecommunications companies that offer discounts on telecommunications services to low-income consumers;
- *Rural Health Care* – provides reduced rates for eligible rural health care providers; and,
- **Schools and Libraries** – provides reduced rates for eligible school and libraries.

Of these programs, the majority of funds are allocated to the high cost program, approximately \$4 billion per year as shown in Figure 5. This approach to rural service expansion in the US represents a form of cross-subsidization whereby the financial burden expanding telecommunication services is spread across the country’s ratepayers. This is comparable to a broad based tax as 96.3% of households in the US were connected to telephone service in 2014.⁷³

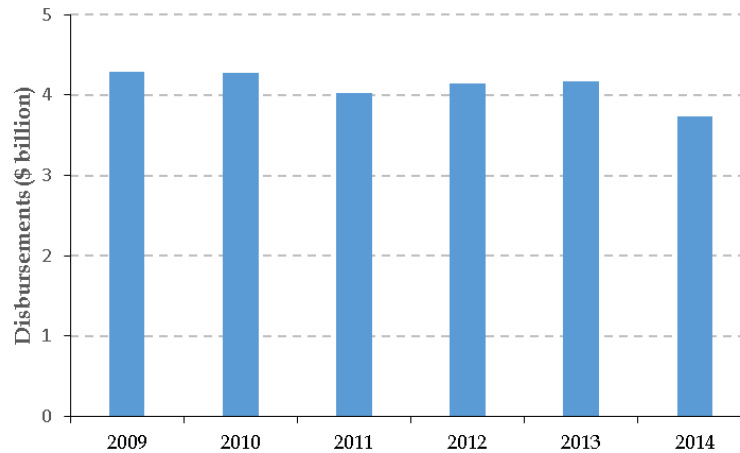
⁷¹ Ibid

⁷² This percentage is known as the contribution factor and is set by the FCC on a quarterly basis depending on the needs of the Universal Service programs. Source: Federal Communications Commission. *Universal Support Mechanisms*. Last accessed: March 1, 2016. <<https://www.fcc.gov/consumers/guides/universal-service-support-mechanisms>>.

⁷³ Federal Communications Commission. *Universal Service Monitoring Report*. September 2014.

As part of the Telecommunications Act of 1934, the deployment of telecommunications services for all Americans is based on the improvement of national security and promoting safety of life and property through the use of wire and radio communication. This rationale may be likened to the consideration of telecommunications service as a public good.

Figure 5. Annual universal service disbursements supporting hard-to-serve rural areas



Source: USAC Annual Reports

4.3.2 Canada - Jurisdiction-wide cross-subsidization

Similar to the US, Canada has made comparable strides in pursuit of universal service. The Telecommunications Act of 1993 describes the federal government’s policy objective, among others, to render reliable and affordable telecommunications services of high quality accessible to Canadians in both urban and rural areas, in all regions of Canada.⁷⁴



Population: 35.9 million
GDP: \$1.79 trillion USD
GDP per capita: \$38,293 USD
Households: 13.3 million
Telecom coverage: 99.2%

Source: World Bank Group, StatsCan, CRTC

To meet the objectives of the Telecommunications Act, the Canadian Radio-television and Telecommunications Commission (“CRTC”) requires Incumbent Local Exchange Carriers (“ILECs”) to provide all Canadians, regardless of where they live, with Primary Exchange Services (“PES”).⁷⁵ Further, this obligation to serve requires ILECs to provide telephone service

⁷⁴ Government of Canada. *Telecommunications Act, 1993*.

⁷⁵ Primary exchange service is a wireline based telephone service that provides customers with unlimited local calling within a defined area at a flat rate, as well as access to a long distance network of the customer’s choice. Source: Canadian Radio-television and Telecommunications Commission. *Telecom Regulatory Policy CRTC 2011-291*. May 3, 2011.

to existing customers, new customers within the ILEC's established facilities and new customers requesting service beyond the limits of the ILEC's facilities.

Using its authority under Section 46.5 of the Telecommunications Act, the CRTC established the local service subsidy regime as a mechanism to ensure that carriers are adequately compensated for the provision of their residential services where the Commission-approved rate charges for basic residential local service do not recover the associated costs of providing that service. Accordingly, subsidies are only provided for high-cost serving areas ("HCSA"), particularly in rural areas.⁷⁶

The subsidy amount is paid on a monthly basis to each local exchange carrier that provides residential network access services ("NAS") to each ILEC HCSA customer group where the cost of providing the service exceeds the subscriber revenue derived from the service. The simplified formula of the subsidy per residential NAS for any given customer group in a HCSA is shown below in Figure 6.

Figure 6. Formula determining the subsidy paid per residential NAS customer group in HCSA

$$\text{Subsidy} = [\text{cost component} \times (1 + \text{inflation} - \text{productivity offset factor})] - \text{rate component} - \text{implicit contribution amount}$$

The cost component is an estimate of the expenses required to provide residential PES. The cost is adjusted every year by the difference of inflation and a Commission-set productivity offset. From the adjusted cost component, for each ILEC, the rates received from a customer are then deducted. Subsequently, a fixed \$5 contribution is deducted, representing the margins generated by optional local services used by residential subscribers.

Subsidies are disbursed from the National Contribution Fund under the direction and approval of the CRTC and are replenished through collections from all Canadian telecommunications companies with annual revenues over \$10 million. Annual revenue-percent contribution rates are set by the CRTC.

⁷⁶ As defined by the CRTC, high-cost serving areas as narrowly defined rate bands that clearly identify those areas where the cost of providing service is substantially higher than the average cost in other parts of the incumbent local exchange carrier's territory. Source: CRTC. *Glossary*. Last accessed: March 1, 2016. <<http://crtc.gc.ca/multites/mtwdk.exe?k=glossary-glossaire&l=60&w=66&n=1&s=5&t=2>>

5 Implications for Ontario

The Ontario government's desire to expand the provision of natural gas services to rural communities represents a public policy objective with the potential to benefit the broader community. As shown above, there are several mechanisms (or combination of mechanisms) which have been adopted across North America including internal utility cross-subsidization, provincial or federal ratepayer cross-subsidies, and taxpayer funding. Figure 7 highlights the advantages and disadvantages of each funding mechanism.

Figure 7. Advantages and disadvantages of funding mechanisms

Funding Mechanisms	Advantages	Disadvantages
Natural gas expansion ratepayers	<ul style="list-style-type: none"> • Direct matching of costs incurred and benefits experiences across the same base • Relatively easy to implement as there is no impact on existing customers 	<ul style="list-style-type: none"> • May cause rates to be significantly higher than other customer classes and therefore uneconomic • A high natural gas rate reduces the incentive for real customers to switch over, resulting in potentially stranded assets • Inconsistent with the goal of public policy mandates such as the LTEP and the Green Energy Act
Internal utility cross-subsidization	<ul style="list-style-type: none"> • Provides economies of scale and ease of administrative implementation • Employed successfully in distribution expansions in other jurisdictions • May allow the surcharge to be spread over a larger base as compared to charging only rural customers 	<ul style="list-style-type: none"> • Increases in costs due to cross-subsidization may not be as small as they would be with a smaller base • Utility customers are paying for positive externalities from which non-customers benefit
Jurisdiction-wide cross-subsidization	<ul style="list-style-type: none"> • Allows the surcharge to be spread over a large base causing the incremental change to be low, minimizing the impact on demand • Since rural natural gas access results in public environmental and wider economic benefits, costs should be broadly socialized 	<ul style="list-style-type: none"> • Other utilities are adversely impacted with increased costs and possibly lower demand, without enjoying the benefits of an increased customer base
Taxpayer funded	<ul style="list-style-type: none"> • Tax mechanisms ensure that the public bears the cost of the distribution expansion since it results in public environmental and wider economic benefits • Avoids discriminating against any one utility and gives new entrant access to funds 	<ul style="list-style-type: none"> • Though minimized through the use of a broad base, the inherent nature of a tax is to potentially distort individual behavior

Historically expansion programs in Ontario were frequently considered uneconomic due to the utility's inability to recover the total costs incurred in expanding the network. Setting a requirement for rural customers to fund the total costs of expansion would not provide customers with sufficient incentive to switch from current energy and heating sources, and also limits a utility's ability to recover its cost of investment.

Subject to the overall cost of expanding the network, internal cross-subsidies within a utility's customer base may allow for sufficient recovery of investment. The total cost impact to a customer, or customer group, can be minimized subject to the cost allocation methods adopted.

Further, from the expansion of its own natural gas network, a utility may benefit from the economies of scale relative to a new entrant providing a similar service. Union's application for expansion of the natural gas network to an additional 18,000 customers can allow for sufficient distribution of costs across Union's broad customer base (1.4 million customers), minimizing the overall impact on demand from the cross-subsidization.

Unlike EPCOR's suggestion to allow new entrants access to Union's customer base, (effectively creating a cross-subsidy between an incumbent utility and new entrants or other existing suppliers) an internal cross-subsidy does not unduly burden one utility's ratepayers at the expense of another utility's costs and revenue requirements. While EPCOR's suggestion may be perceived as a viable funding mechanism, it is likely to exacerbate the known negative effects associated with cross-subsidies more broadly, including violating the cost causation principle (without accounting for the return of an entity), and increasing the administrative burdens as a result of having more than one entity associated with the subsidy. Finally, whereas with internal cross subsidization, any potential economies of scale associated with the delivery of expansion projects would ultimately be realized by the incumbent's customers, that is not the case if those customers are forced to subsidize a neighboring competitor.

An alternative approach to EPCOR's suggestion would be to distribute the costs of expanding the network via a jurisdiction-wide cross-subsidy paid by all ratepayers, or through implementation of a broad-based tax regime. This would avoid undue burden on a single utility's customer base, while recognizing the wider environmental and economic benefits that may be accrued through investment in a public good.

6 Appendix A: List of Works Consulted

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7 Appendix B: LEI Credentials

London Economics International LLC is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as natural gas distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design and analysis. LEI has worked extensively in North America, Europe, Asia, Latin America, Africa, and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

The following attributes make LEI unique:

- *clear, readable deliverables* grounded in substantial topical and quantitative evidence;
- *internally developed proprietary models* for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;
- *balance of private sector and governmental clients* enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;
- *ability to estimate relative efficiency levels* and efficiency frontiers provides expertise to advise on network tariffs and design rates under performance-based ratemaking; and
- *worldwide experience* backed by multilingual and multicultural staff.

7.1 Performance Based Ratemaking and Natural Gas Experience

Ontario distribution rates re-design: LEI advised the Coalition of Large Distributors in Ontario on third generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board. The work involved expert testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with comparison of actual factors and indices, and determination of the more robust and appropriate indices for the Ontario's distribution industry, including total factor productivity analysis for the sector.

Review of gas distribution PBR regimes across North American jurisdictions: LEI was engaged by Union Gas to review Union's proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, Union particularly requested LEI to examine approaches to a set list of ratemaking parameters:

productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism (“ESM”), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas (“UFG”), and service quality indicators (“SQIs”) and how they are measured. LEI was subsequently requested by Union to provide comments on Union’s draft Settlement Agreement.

Testimony on using building blocks approach in PBR frameworks: LEI was engaged by Enbridge Gas Distribution to provide an analysis of building block incentive ratemaking approaches used in Australia and the UK, and how they would apply to Enbridge’s circumstances in Ontario. LEI’s report supported Enbridge’s distribution tariff proposal submission to the Ontario Energy Board for a second-generation Customized Incentive Regulation (“IR”) plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. LEI supported Enbridge throughout the regulatory proceeding, including providing additional reports to respond to interrogatories.

Productivity study for generation assets: LEI assisted an Ontario electricity generator in performing a total factor productivity (“TFP”) study on their hydroelectric assets to fulfill the mandate of the Ontario Energy Board (“OEB”). LEI proposed a structured approach to address how productivity should be measured, what methods are available, to identify a relevant peer group, and ultimately to provide the client with a productivity study for filing with the OEB.

Applicability of PBR to OPG regulated assets (nuclear and hydro-electric): LEI was engaged by Ontario Power Generation (“OPG”) to support senior management through regulatory processes related to performance-based rates. LEI prepared a discussion paper on incentive regulation mechanisms (“IRM”) currently in place in Ontario for electricity and natural gas distribution utilities and presented it at a technical workshop at the Ontario Energy Board (“OEB”). LEI continues to support OPG as it moves to consider its next generation of rates.

Second generation PBR in Ontario: LEI President A.J. Goulding led a Cdn. \$1.5 million engagement focusing on design of second generation PBR in Ontario. Key components include estimating total factor productivity (TFP), determining appropriateness of yardstick competition, analyzing demand-side management programs in the context of PBR, and examining service quality indicators.

Considering conservation and demand management in incentive ratemaking frameworks: LEI assisted the Ontario Energy Board in identifying options for a ratemaking framework that account for electricity distributor conservation and demand management (C&DM) in electricity distribution rates. As part of the work, LEI presented various models and compared them on the basis of five key criteria: administration, rate impact, regulatory consistency, incentive compatibility, and universality.

Incentive mechanisms for OPG legacy assets: For Ontario Energy Board, LEI prepared a paper which described the ways in which legacy assets of Ontario Power Generation could be

regulated, including incentive regulation and a set of regulatory contracts. Deliverables included providing technical advisory during public workshop.

Cost of capital for regulated generating assets: LEI provided expert testimony on behalf of the Ontario Energy Board regarding cost of capital and risk factors associated with OPG's prescribed assets, as well as creating a risk-return continuum on which power sector assets could be placed.

7.2 Cost Causation Experience

Transmission cost causation study for the Alberta Electric System Operator ("AESO"): The study was used for the determination of the AESO's Demand Transmission Service Rate DTS, and was filed with AESO's 2014 tariff application to the Alberta Utilities Commission ("AUC"). The study covered four main topics: (i) Functionalization of Capital Costs; (ii) Functionalization of Operating & Maintenance ("O&M") costs; (iii) Classification of Bulk and Regional System Costs; and (iv) Implementation Considerations.

Self-funding tariff for ISO New England including cost causation study: LEI provided support for ISO New England throughout the design and submission to FERC of ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, frequent interaction with stakeholders, and written testimony before FERC.

Economic advice on cost causation and tariff regime: LEI provided Australia's former power market regulator, NEMMCO, economic advice on the appropriate regime for charging market participants for the costs incurred by the client in providing its services, in accordance with the National Electricity Code. In making its recommendation on participant fees, LEI considered the criteria specified by the National Electricity Code. LEI also considered the issues and arguments raised in submissions provided by participants in response to the issues paper released in December 1999.

Methodologies for transmission cost allocation: LEI advised a state public utilities commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology.

Distribution cost allocation and customer class definition: LEI, in consortium with an engineering firm, analyzed the customer density and distribution service costs for one of Ontario's largest utility. This engagement had three specific objectives: (i) evaluate the relationship between customer density and distribution service costs; (ii) assess whether utility's existing density-based rate classes and density weighting factors appropriately reflect this relationship; and (iii) consider, qualitatively, the appropriateness and feasibility of establishing alternative customer class definitions.

Cost of service tariff design for electricity, water and wastewater services in Saudi Arabia: On behalf of a utility serving industrial areas in Saudi Arabia, LEI developed a regulatory framework for power and water utilities not regulated by the government, developed a charter for a new regulatory body, established and recommended cost of service (and alternative incentive regulation) based tariff structure and accompanying tariff model for all business activities, and assisted filing of tariff petitions with the applicable regulatory authorities for approval.

Design of wheeling tariff and pilot program for Saudi Arabia: For the Saudi regulator, developed proposed plan for wheeling of power in Saudi Arabia, including proposed pilot program, assessment of impact on incumbent, relative economics of wheeling versus the industrial tariff, and review of associated commercial and regulatory issues.

Tariff design for Kingdom of Saudi Arabia: Led engagement with international team assessing tariff design, modeling, and electricity market evolution in Saudi Arabia; engagement resulted in a revised tariff system, including performance based rates, tolling agreements for generation, and an open access tariff. Included holding workshops for regulator in explaining cost of capital, tariff design, and other regulatory issues.

7.3 Regulatory Experience in Ontario

Testimony on behalf of Enbridge Gas Distribution regarding ratemaking approaches: LEI was engaged by Enbridge Gas Distribution to provide an analysis of building block incentive ratemaking approaches used in Australia and the UK, and how they would apply to Enbridge's circumstances in Ontario. LEI's report supported Enbridge's distribution tariff proposal submission to the Ontario Energy Board for a second-generation Customized Incentive Regulation ("IR") plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes.

Presentation to the Ontario Energy Board (OEB) on regulatory options for setting payments for the output from Ontario Power Generation's prescribed assets: the oral presentation was a follow up on a written submission provided by LEI to the OEB on alternatives for regulating prices associated with output from designated generation assets in Ontario. [OEB, proceeding ID: EB-2006-0064]

Cost of capital for regulated generating assets: LEI provided expert testimony on behalf of the Ontario Energy Board regarding risk factors associated with Ontario Power Generation's prescribed assets, as well as creating a risk-return continuum on which power sector assets could be placed. [OEB, proceeding ID: EB-2007-0905]

Advice on performance-based ratemaking: LEI advised the Coalition of Large Distributors in Ontario on 3rd generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board. The work involved expert testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with comparison of actual factors and indices, and determination of the more robust and appropriate

indices for the Ontario's distribution industry, including total factor productivity analysis for the sector. [OEB, EB-2007-0683]

Comments on OEB's consultation paper on benchmarking of distribution companies: Julia provided comments on the benchmarking methodology suggested by OEB consultants, looking at the analytical aspects of defining and benchmarking the performance of multiple utilities across long period of time. The critique provided details on how each criterion affects the benchmarking study and what are the remedies available to improve the results. [OEB, EB-2006-0268]

Conservation and Demand Management (C&DM) in Ontario: LEI prepared testimony related to the alternative ratemaking approaches available regarding C&DM; addressed innovative alternatives and compared and contrasted various schemes in the Ontario context. [OEB, Proceeding ID: RP-2004-0188]