Enbridge Gas Compendium for Direct Examination of Panel 10 (Customer Attachment Policies)

	Item
1.	EBO 188 Final Report of the Board, January 30, 1998
2.	EB-2016-0004 Decision with Reasons, OEB Generic Proceeding on Community Expansion
3.	Gas Distribution Access Rule (GDAR), section 2
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E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

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1. THE PROCEEDING

1.1 THE BACKGROUND

1.1.1 In a Notice of Public Hearing dated July 31, 1995, the Ontario Energy Board ("the Board") made provision to hold a public hearing under subsection 13(5) of the Ontario Energy Board Act ("the OEB Act", "the Act") to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra"), (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188.

1.1.2 In Procedural Order No. 1 the Board ordered the utilities to file their current policies for determining the feasibility of proposed system expansions and the application of environmental study reports.

1.1.3 The Board held an Issues Day meeting on September 11, 1995 and heard submissions on a proposed Issues List. The Board finalized the Issues List in Procedural Order No. 2 dated September 14, 1995.

1.1.4 Procedural Order No. 3, dated October 27, 1995, made provision for parties to file evidence and interrogatories on the evidence. The Order also provided for an alternative dispute resolution ("ADR") conference to be held commencing December 11, 1995 ("the first ADR Conference").

1.1.5 The Board received the *Report to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas*

System Expansion in Ontario, on December 21, 1995 ("the first ADR Report"). There were divergent views expressed in the first ADR Report by the parties with respect to the principles involved in system expansion.

1.1.6 Having reviewed the first ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order, the Board directed that the parties choosing to file argument and reply should focus their submissions on the following issues:

> *1.1 Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:*
>
> > *(1) an obligation to serve in areas where existing service is available;*
> > *(2) externalities;*
>
> *If externalities are to be included, what specific externalities, i.e. economic, social, environmental, should be considered? What tests should be applied and in what sequence?*
>
> *1.2 Given the answer to 1.1, what level of financial subsidy, if any, should be applied to system expansion;*
>
> *1.3 Should a portfolio of projects be utilized or should the utilities account for expansion on a project-by-project basis? How should the portfolio be defined?*

1.1.7 Submissions were filed on February 2, 1996 and reply submissions were filed on February 19, 1996.

1.1.8 An Interim Report of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects. The Board directed the parties to develop guidelines and policies reflecting the Board's conclusions. The Board also determined that the continuation of the proceeding should be by way of written submissions and a further ADR Settlement Conference ("the second ADR Settlement Conference").

1.1.9 A written common submission was filed by the utilities on September 30, 1996, and submissions and comments on the utilities' common submission were received from Board Staff, Consumers' Association of Canada, Canadian Industry Program for Energy Conservation, Industrial Gas Users Association/City of Kitchener, Green

Energy Coalition, Northwestern Ontario Municipal Association/Federation of Northern Ontario Municipalities, Pollution Probe and Ontario Federation of Agriculture/Ontario Pipeline Landowners' Association.

1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of:

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities and supported by a number of other parties ("ADR Agreement"), which included proposed System Expansion Guidelines;
- a dissent in the form of a document entitled "Deficiencies of the E.B.O. 188 ADR Agreement and their Rectification" dated April 1, 1997 ("Dissent Document");
- letters of comment from various parties on the ADR Agreement and Dissent Document; and
- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities.

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A.

1.1.12 In preparing this Final Report, the Board has considered the above documents. The resulting *Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)* ("the Guidelines") are issued as Appendix B to this Report.

1.1.13 The following chapters set out the issues and the principles established in the Interim Report by quoting directly from that document. The positions of the parties are outlined by referencing the ADR Agreement, the Dissent Document and the various comments and clarifications made.

1.1.14 The Board's comments and findings are structured as:

- The Portfolio Approach
- Common Methods for Financial Feasibility Analysis
- Customer Connection and Contribution Policies

- Environmental Planning Requirements for System Expansion
- Monitoring and Reporting Requirements

1.1.15 As of January 1, 1998, Union and Centra merged into a single company, Union Gas Limited. The Board's findings in this Report and in the Guidelines are applicable to the new company and to Consumers Gas.

1.2 INTERVENTIONS

1.2.1 The following parties intervened in the proceeding:

- Canadian Association of Energy Service Companies
- City of Kitchener
- Consumers' Association of Canada
- Energy Probe
- Federation of Northern Ontario Municipalities
- Green Energy Coalition
- Grenville-Wood
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
- Industrial Gas Users Association
- Municipal Electric Association
- Natural Resource Gas Limited
- Northwestern Ontario Municipal Association
- Ontario Coalition Against Poverty
- Ontario Federation of Agriculture
- Ontario Hydro
- Ontario Native Alliance
- Ontario Pipeline Landowners' Association
- Ottawa-Carleton Gas Purchase Consortium
- Pollution Probe
- Power Workers' Union
- TransAlta Energy Corporation
- TransCanada PipeLines Limited
- Woodland Hills Community Inc.

Late Interventions

- The British Columbia Ministry of Energy, Mines and Petroleum Resources
- Canadian Industry Program for Energy Conservation
- Ecological Services For Planning Inc.
- F & V Energy Co-operative Inc.
- StampGas Inc.

2. THE PORTFOLIO APPROACH

2.1 INTERIM REPORT CONCLUSIONS

2.1.1 *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

2.1.2 *The Board is of the view that all distribution system expansion projects should be included in a utility's portfolio. This includes projects being developed for security of supply and system reinforcement reasons. The Board will be prepared on an exception basis to consider a utility's submissions as to why a proposed project should not be included in the portfolio but treated separately.*

2.1.3 *The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. [Profitability Index] or benefit to cost ratio in the portfolio. The Board finds that using a rolling P.I. such as the approach used by Union will allow more opportunity for new projects to be added to the portfolio in a more timely fashion and that this is in the public interest. Union's rolling P.I. is a weighted average calculation of the cumulative net present value ("NPV") inflows divided by the cumulative NPV outflows during the preceding 12 months.*

2.1.4 *The Board expects the utilities to develop common policies on calculating rolling P.I.s. The forecast rolling P.I.s at a given point in time will be compared to the* *actuals in each utility's rates case to determine if any action needs to be taken with regard to forecast variances.*

2.1.5 *The Board recognizes that subsidization can be measured at both the project and portfolio level. An overall rolling portfolio P.I. of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion. The Board is therefore of the view that an overall portfolio P.I. of 1.0 <u>or better</u> (emphasis added) is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.*

2.1.6 *However, at the present time the utilities calculate the DCF ["discounted cash flow"] for proposed projects over long periods of time. The P.I. or benefit to cost ratio is based on this calculation. In the early years, the costs shown in the calculation generally exceed the revenues and there is a greater impact on rates than in the later years when revenues generally exceed costs. The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0 the impact on rates in a given year may be undue. For this reason, the Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue burden on existing ratepayers.*

2.1.7 *The Board has considered whether or not it should impose a minimum threshold P.I. for projects to be included in the portfolios. The Board is concerned that the utilities may proceed with a number of projects with low P.I.s even though the P.I.s of the portfolios remain at 1.0 or greater. The cumulative impact of these projects may result in economic inefficiencies that outweigh the public benefit of the portfolio approach. From time to time, the Board will review the project specific data to monitor the operation of the portfolios in order to determine whether the cumulative economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.*

2.2 POSITIONS OF THE PARTIES

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement:

i. service lines off existing mains are included;
ii. security of supply projects are not included; and
iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD'S COMMENTS AND FINDINGS

Investment Portfolio

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, the Investment Portfolio, all proposed new distribution customer attachments and facilities for a particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts.

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis.

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods.

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects.

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4).

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year.

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the

Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate.

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts.

Rolling Project Portfolio

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D).

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate.

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes.

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate.

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS

3.1 INTERIM REPORT CONCLUSIONS

3.1.1 *The Board believes that a further review of the methodology to be used by the utilities in assessing the project and portfolio financial feasibility is necessary. Among the factors to be considered are the period for new attachments and the time period over which the DCF analysis is calculated. The Board expects utilities to develop common methods for the Stage I Financial Feasibility test that will be used to show whether or not each utility's portfolio of distribution system expansion projects is profitable.*

3.2 POSITIONS OF THE PARTIES

3.2.1 The ADR Agreement set the following parameters for the DCF analysis:

(a) Customer Attachment Horizon

A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board.

(b) Customer Revenue Horizon

The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service.

(c) Discount Rate

The Utilities' incremental after-tax cost of capital will be used for the discount rate. This will be based on the prospective capital mix, debt and preference share costs, and the latest Board approved equity return levels.

(d) Discounting

Discounting will reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures.

(f) Gas Costs

In the near term, the weighted average cost of gas ("WACOG") will continue to be the proxy for gas costs (gas costs shall be WACOG less the commodity portion of the gas costs). This approach may not be appropriate in the case of projects for large customers, where a specific gas cost forecast may be required.

3.2.2 The parties to the Dissent Document submitted the ADR Agreement was deficient in that the utilities had not agreed on a common method for calculating their P.I.s; that a 40 year revenue horizon may result in existing customers paying undue rate increases; and that 40 years is inappropriate in the absence of shareholder responsibility for forecast variations.

3.2.3 The Dissent Document also stated that the utilities were understating the costs in the financial feasibility analysis, since they are not using incremental costs for gas storage and transportation services, but have proposed that gas costs be WACOG less the commodity portion of gas costs.

3.2.4 The Dissent Document proposed:

- a customer attachment horizon no longer than 5 years (unless there is a specific contract);
- a maximum time period for the DCF calculation of 20 years from the in-service date of the initial main for large volume customers and between 20 and 30 years for small volume customers;
- customer use volumes representing the best estimates of the gas consumption for new customers; and
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission.

3.3 BOARD'S COMMENTS AND FINDINGS

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the development of the elements of the financial feasibility test. These elements include: customer attachment horizon, customer revenue horizon, discount rate and timing, operating and maintenance expenditures, and weighted average gas costs.

3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum and adopts this as part of the Guidelines in Appendix B.

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of projects with very long cash flow break-even periods and hence high levels of subsidy in the early years. The Board has addressed this issue as part of the design targets for the Investment Portfolio.

3.3.4 The Board concludes that, although theoretically correct, the inclusion of forecast incremental costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess short term rate impacts at the Portfolio level. This would be similar to the Rate Impact Measure (“RIM”) Test used to evaluate Demand Side Management (“DSM”) programs, with the objective of allowing comparisons from year to year and, to a degree, among the separate portfolios of the utilities.

3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as proposed in the ADR Agreement. These common elements will be reflected in the DCF analysis for the Investment Portfolio and the Rolling Project Portfolio filed by each of the utilities in its rates cases, the details of which are set out in Appendix B.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

4.1 INTERIM REPORT CONCLUSIONS

4.1.1 *In the last few years, the Board has approved contributions in aid of construction in the form of periodic contribution charges for residential and small commercial customers in order to improve the profitability of projects when the P.I. or benefit to cost ratio is less than 1.0.*

4.1.2 *The Board notes that accidents of timing and geography can ... lead to inequitable situations where some ratepayers in similar situations may not have to pay a contribution while others are required to pay contributions.*

4.1.3 *The Board realizes that customers have indicated their willingness to contribute towards the cost of projects that are not financially feasible in order to obtain gas service. The Board also notes that there may be communities that would be so costly to serve and the P.I. so low that they are unlikely ever to be included in the portfolio. The Board accepts that in these special circumstances a contribution in aid of construction from a community would be acceptable on a case by case basis, but the Board will not expect the utilities to require contributions from all projects which do not meet a threshold P.I. of 1.0. In light of these considerations, the Board expects the utilities to prepare common guidelines on the treatment of customers currently paying periodic contribution charges.*

4.1.4 *The Board will review in the next phase of this proceeding the utilities' policies on requiring contributions in aid of construction where dedicated facilities are being constructed primarily for a single customer. In this regard the Board is interested in a policy that deals with all customer classes and expects the utilities to prepare a policy that is common among the utilities.*

4.2 POSITIONS OF THE PARTIES

4.2.1 The ADR Agreement states that the utilities will accept contributions in aid of construction for communities or projects that would otherwise not likely be included in the portfolio.

4.2.2 The ADR Agreement also proposed that existing contractual arrangements for the collection of contributions continue with the exception of Consumers Gas' projects for which contributions would be adjusted to achieve a P.I. of 0.8.

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered \"Adedicated".

4.2.4 The Dissent Document does not address the issue of customer contribution policies.

4.3 BOARD'S COMMENTS AND FINDINGS

4.3.1 The Board notes that the utilities wish to retain the ability to accept contributions in aid of construction for communities or projects that would not otherwise be included in the portfolio. However, no cost limits or P.I. thresholds have been recommended by the parties to assist the utilities in making such decisions. As stated in the Interim Report, the Board believes that the utilities should continue to make decisions on contributions in an even handed manner.

4.3.2 The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio.

4.3.3 The Board directs the utilities to prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:

i. the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and

ii. the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities.

4.3.4 The Board agrees with the parties that the common criteria for contributions in aid of construction should apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion.

4.3.5 The Board expects the utilities to bring forward common proposals for customer connection and contribution policies for Board approval. These proposals will be reviewed in each of the utilities' rate cases.

5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION

5.1 INTERIM REPORT CONCLUSIONS

5.1.1 *The Board requires that for all distribution projects, the utilities prepare a display of alternatives (routes and sites) which would show the various trade-offs between customer attachments and environmental, social and financial costs. The Board expects the utilities to prepare common guidelines on how to conduct and document the evaluation of their route selection and to apply these to all expansion projects.*

5.1.2 *The Board also expects the utilities to appropriately apply the [Board's] Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario, Fourth Edition, 1995 ("the Environmental Guidelines") to all distribution system projects whether or not they involve a facilities application to the Board. The Board believes that the type and level of detail of the environmental investigations conducted by the utilities should be determined on the basis of environmental significance, and not on whether or not a particular application comes before the Board, whether a proposed pipeline is a distribution or transmission line, or whether or not the line will be located in a town. The utilities should conduct and document the necessary investigation and develop mitigation measures where significant environmental features are encountered. It is expected that the utilities will not require additional resources to undertake these investigations.*

5.1.3 *The utilities will have to confirm in their rates cases that all proposed projects meet the guidelines on route selection and the Environmental Guidelines and if not, why not. In addition, for facilities applications, the Board expects the utilities to file the* *project specific route selection display and environmental report. The Board expects that the utilities may incorporate the route selection evaluation into their environmental report.*

5.1.4 *The requirements to conduct and document the evaluation of the route selection and to apply the Environmental Guidelines to all distribution projects will be incorporated in the Environmental Guidelines.*

5.1.5 *In facilities applications the utilities will also have to continue to satisfy the Board on the design and construction practices and costs for the project. In addition, the Board will have to be satisfied that landowner concerns have been met and that any necessary permits have been obtained.*

5.2 POSITIONS OF THE PARTIES

5.2.1 The ADR Agreement proposed that whenever a need for gas is identified, and a reasonable source is available, an evaluation would be done on whether this need could be accommodated. Full information on service alternatives would be gathered, including potential customers served, the running line location, construction costs and environmental and socio-economic concerns.

5.2.2 In selecting a preferred route, the ADR Agreement stated that standard environmental guidelines will be used for dealing with most environmental features. Significant environmental features (those not covered by the utilities' standard environmental guidelines) will require separate evaluation and may require public meetings and agency consultation.

5.2.3 The ADR Agreement proposed that costs of avoiding significant environmental features or mitigating significant environmental impacts will be included in the cost and benefit analysis for the project. For projects with similar economic benefits, routes that avoid significant environmental features will be preferred. Generally, routes with the greatest economic benefits overall will be preferred, subject to the environmental considerations described above.

5.2.4 The parties to the Dissent Document submitted that the ADR Agreement is not consistent with the Board's Interim Report because:

i. the utilities have not yet developed common guidelines on how to conduct and document the evaluation of their route selection; and

ii. according to the ADR Agreement, the utilities can select a route that will cause significant harm to the local environment if the route's economic benefits exceed its costs to the environment.

5.2.5 The parties to the Dissent Document proposed that the utilities be required to prepare and apply common guidelines on how to conduct and document the evaluation of their route selections to all expansion projects.

5.2.6 Energy Probe, the Green Energy Coalition, and Pollution Probe proposed that the utilities should be required to adopt as a principle that there should be "no net loss" of local environmental resources as a result of their system expansion activities. Where a utility is unable to offset the environmental impacts of its system expansion activities, the utility should make best efforts to create an offsetting environmental resource to meet the "no net loss" principle.

5.3 BOARD'S COMMENTS AND FINDINGS

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less public scrutiny of the financial and economic evaluation of individual system expansion projects. However this does not imply that there should be any decrease in the necessary level of environmental assessment of projects by the utilities, or the documentation of this work, as these matters will continue to be reviewed by the Board.

5.3.2 The planning principles described in the Board's Environmental Guidelines shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined by the utilities in a manner consistent with the Environmental Guidelines based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. Environmental significance is to be determined based on the expected impacts of a particular project, not on whether the feature is covered by the utility's environmental guidelines.

5.3.3 To assist in determining what level of planning, investigation and reporting is necessary, the Board finds that the utilities shall jointly develop a common set of environmental screening criteria to determine if significant environmental features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be jointly developed and applied by each utility depending on the impacts expected as determined through the screening process. The criteria and corresponding requirements can be in the form of a checklist. The Board will review the screening criteria and the corresponding planning, documentation and reporting requirements for inclusion in the Environmental Guidelines. The Board expects the utilities to submit this material to the Board by June 1, 1998.

5.3.4 Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters shall identify potential impacts through the screening process and determine the level of planning required. Depending on the significance of the potential impacts anticipated, the decision on the level of planning may involve additional environmental specialists of the utility, external consultants and other affected parties.

5.3.5 Depending on the level of significance of the environmental feature(s) encountered, the planning may involve alternative routing/siting considerations, detailed mitigation requirements and/or public and/or agency review. It is expected that the criteria and requirements will be updated from time to time by the utilities in consultation with other interested parties and reviewed by the Board for inclusion in updated Board Environmental Guidelines.

5.3.6 Where alternative routes or sites are investigated, the Board expects that the preferred alternative will be chosen based on an optimization of the particular environmental, social and financial criteria for the project. Decisions on the relative importance of these criteria are to be made based on the specific environmental features encountered and their significance, rather than deciding in advance that financial criteria have priority.

5.3.7 In those cases where the significance of environmental features may be in question or the planning requirements are not clear, the utilities are expected to consult with environmental specialists, Board Staff and affected parties. The Board expects that as experience is gained, consultation will be necessary only in unusual cases. In all cases however, it is expected that provincial and local agency requirements (permits, licences) shall be obtained where necessary and that the utilities will apply their standard guidelines, drawings, and specifications.

5.3.8 The Board finds that further examination of the "no net loss" principle is unnecessary in this proceeding in light of the Board's specified environmental planning requirements.

6. MONITORING AND REPORTING REQUIREMENTS

6.1 INTERIM REPORT CONCLUSIONS

6.1.1 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.2 *Despite the advantages of a portfolio approach, the Board is of the view that certain containment practices should be put in place in order to ensure that:*

- *ratepayers are protected from financially risky decisions on expansion by the utilities;*
- *the utilities make decisions on which projects should proceed in an even-handed manner;*
- *the cumulative impact on rates is not undue in any given year;*
- *the continued expansion of natural gas service is in the overall public interest; and*
- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.*

6.1.3 *Utility shareholders will be held responsible for any significant variation in the forecast of customer attachments, volumes and costs from the aggregate portfolio. The Board expects the utilities to make proposals in the next phase of this proceeding on how variances from the aggregate forecast should be treated in order to appropriately share the risk between ratepayers and shareholders. In considering how the risk should be shared, the utilities may want to review their policies on obtaining financial assurances from new large volume customers.*

6.1.4 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.*

6.1.5 *However, the Board finds that it is in the public interest to require the utilities to demonstrate that it continues to be in the overall public interest to expand the natural gas distribution systems from an aggregate economic, social and environmental point of view. Therefore, the Board will require utilities to file the results of a societal cost test ["SCT"] of their overall portfolios of distribution system expansion when seeking approval of their portfolios. The societal cost test could include monetized, non-monetized and qualitative components. To this end, the Board requests the utilities to develop a common evaluation method, that would be cost-effective, that would adequately characterize performance, and that would be relatively straightforward to apply.*

6.1.6 *The Board expects the utilities to develop common reporting requirements so that the utilities' forecast P.I.s, customer attachments, volumes and costs can be compared to actuals on a portfolio basis and, if need be, on a project specific basis. This information shall be put on the record in the rates cases to serve as a benchmark.*

6.1.7 *The Board expects that under the portfolio approach the Stage I financial feasibility P.I. will be calculated for each proposed project as well as for the portfolio of infill projects. For the purposes of calculating the P.I. of the infill portfolio, infill projects are defined as the extension of mains and service attachments in existing service areas, but does not include service lines to individual customers off existing mains.*

6.1.8 *All the P.I.s of the proposed projects and the infill portfolio will be aggregated to calculate the overall portfolio P.I. at a given time for each utility.*

6.2 POSITIONS OF THE PARTIES

6.2.1 The ADR Agreement proposed that the utilities file Test Year and Historic Year information as part of their rates cases. This information would include the capital amounts, profitability and rate impacts of the Investment Portfolio and the Rolling Project Portfolio; actual expenditures on reinforcement costs; and specific customer attachment information on a set of randomly selected projects.

6.2.2 The ADR Agreement also proposed that each utility file in its rate case a projected NPV of the results of a SCT for the Investment Portfolio for the test year. The results would be presented both with and without monetized externality costs and benefits.

6.2.3 The parties to the Dissent Document submitted that the ADR Agreement fails to meet the Board's direction in the Interim Decision because:

- the ADR Agreement does not require the utilities to report the P.I.s of their Investment Portfolios or any individual project within their Investment Portfolios;

- the ADR Agreement does not require the utilities to report the forecast aggregate NPV and P.I. of the test year's projects that have negative P.I.s (information necessary to address the Board's concern with respect to economic efficiency); and

- the ADR Agreement does not require the utilities to put on the record in their rates cases project specific P.I.s, customer attachments, volumes and cost data so that project specific information can serve as a benchmark for monitoring performance on an on-going basis.

6.2.4 The parties to the Dissent Document further submitted that the ADR Agreement fell short because:

- there is no commitment to provide a comparison of actual and forecast volumes;

- there is no commitment to provide a comparison of actual and forecast capital expenditures for the Investment Portfolio; and

- the utilities are only committed to providing a comparison of their actual and forecast customer attachments for the first three years of a project's life, which does not cover the remaining 7 years in a project's 10 year customer attachment forecast period.

The parties to the Dissent Document proposed that the utilities should be required to file portfolio and project specific information for the historic, bridge and test years.

6.3 BOARD'S COMMENTS AND FINDINGS

6.3.1 The Board believes that the principles outlined in the Interim Report should form the basis of the monitoring and reporting requirements.

Rate Case Review

6.3.2 The Board directs that the utilities file, in their respective rates cases, a forecast NPV and P.I. of the test year Investment Portfolio. In subsequent rates cases, each utility will report to the Board on the actual results of the Investment Portfolio.

6.3.3 The actual results of the Investment Portfolio will present the NPV and the P.I. taking into account the capital spent, the number of customers attached and the revenues received from the customers attached in the most recent historical year for which there is full data. Volume usage for larger commercial and industrial customers will be individually estimated to more closely reflect actual annual volumes.

6.3.4 Each utility will, in its rates case, provide an analysis of the estimated rate impact of its Investment Portfolio in the first five years of service. As referred to earlier, the Board found the material filed by Consumers Gas in E.B.R.O. 495 at Exhibit I, Tab 7, Schedule 8, to be a good example of the information necessary, but would be further assisted if the impacts were broken down by rate class. The Board directs that such a breakdown be included in the required impact analysis.

6.3.5 As noted earlier, the Board also wishes the utilities to use a standard rate impact test or measure similar to the R.I.M. test used to assess DSM program impacts. This measure should present the following information in aggregate and by rate class:

- impact of the Investment Portfolio cash flow on the test year revenue deficiency; and
- the ratio of incremental revenues to costs in the test year and subsequent three years.

6.3.6 The Board notes that in recent rates cases both Centra and Consumers Gas have significantly overspent their Board-approved capital budgets, particularly in the bridge year. In its E.B.R.O. 493/494 Decision the Board set out the criteria of *affordability* and *rate stability* as key factors affecting the capital budget and additions to rate base, which the Board will consider in assessing prudence of expenditures.

6.3.7 The Board notes that the addition of capital for assets such as Information Technology and Customer Information Systems may have significant impacts on both the level of capital expenditure and year to year additions to rate base. The Board in its E.B.R.O. 493/494 Decision suggested that affordability criteria be applied to develop ceilings for capital expenditures and rate stability criteria be used to manage the scheduling of expenditures on more discretionary projects in conjunction with system expansion projects. In addition, in E.B.R.O. 495 the Board expressed its concern about the upward pressure on rates resulting from continual system expansion, and concluded that, for ratemaking purposes, expenditures above overall Board-approved levels in various categories ("envelopes") of the capital budget could not automatically be included in the Company's proposed rate base for the next fiscal year. In addition, the Board cautioned that the Company would be required to prove the reasonableness of its capital expenditures within each envelope, even if the expenditures were at or below the Board approved level.

6.3.8 The Board expects that the concerns raised in these recent rate cases regarding affordability and rate stability will be addressed in the utilities' plans under the portfolio approach.

6.3.9 The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers.

6.3.10 The Board agrees with the ADR proposal for portfolio level SCT analysis, monitoring and reporting, using a test that is consistent with the treatment of the SCT for DSM.

Ongoing Monitoring and Reporting

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B are to streamline the process of approval of system expansion projects and achieve a commonality of approach between the utilities, while ensuring that ratepayers are protected against the impacts of either over-aggressive, or financially inappropriate, system expansion by the utilities.

6.3.12 The Board believes that the achievement of these objectives requires periodic standardized reporting to the Board, as well as the filing of information in rate cases in order to allow the prudence of the utilities' actions and rate impacts to be reviewed. These reviews should appropriately be rate focussed with account taken of both short-term and long-term costs and benefits to ratepayers.

6.3.13 The Board considers that, in general, the ADR Agreement proposals in the section *Monitoring the Performance of the Portfolios/Short Term Rate Impacts*, provide a reasonable point of departure and that experience should show whether the content and timing of the monitoring and reporting requirements are adequate. The Board will require filing of the P.I.s of the portfolios as well as the NPVs. The adjusted monitoring requirements are included in the Guidelines in Appendix B.

6.3.14 The Board emphasizes that the utilities must maintain clear records at a project specific level that will allow for inspection and/or reporting of individual projects as may be deemed necessary from time to time.

6.3.15 The Board will require quarterly filing of the monthly reports on the Rolling Project Portfolio and total capital expenditures in order to monitor performance.

6.3.16 The approach to environmental planning outlined above should simplify the documentation requirements. The sampling process and reporting required in the Guidelines will ensure consistency across projects and between utilities and ensure compliance with the Board's environmental planning requirements.

7. COMPLETION OF THE PROCEEDING AND COSTS

7.1 COMPLETION OF THE PROCEEDING

7.1.1 The Board has reviewed the letters of comment setting out the positions of various parties on the ADR Agreement and the Dissent Document. The Board is of the view that it would not be in the public interest at this stage to hold additional hearings on this matter. Rather, the Board believes that the public interest is better served by proceeding with the implementation of the Guidelines included in Appendix B of this Report.

7.1.2 The Board directs that the Guidelines shall be implemented as soon as possible, but no later than the 1999 fiscal year for each of the utilities. The Guidelines will be subject to future review by the Board in the light of experience gained in their application.

7.2 COSTS

7.2.1 In the Board's Interim Decision of August 15, 1996 the parties to the proceeding were directed to submit cost claims for that phase of the proceeding. The Board made an interim cost award to those parties requesting one.

7.2.2 The Board directs all parties who wish to do so, to submit their final claim for costs with the Board and a copy to each of the utilities, taking into account the interim cost award (if applicable) by February 20, 1998. Comments from the utilities are to be filed by March 2, 1998 and reply by parties by March 16, 1998. The Board will issue its Cost Award Decision and Order in this proceeding in due course.

7.2.3 The Board directs the utilities to pay the Board's costs of, and incidental to the proceeding upon receipt of the Board's invoice.

7.2.4 The Board directs that all costs be apportioned on a 50:50 basis between Consumers Gas and Union/Centra Gas.

DATED AT TORONTO January 30, 1998.

G.A. Dominy
Vice Chair and Presiding Member

R.M.R. Higgin
Member

J. B. Simon
Member

APPENDIX A

Parties Concurring with the ADR Agreement

Board Staff
City of Kitchener
The Consumers' Gas Company Ltd.
Consumers' Association of Canada
Federation of Northern Ontario Municipalities
Northwestern Ontario Municipal Association
Ontario Federation of Agriculture*
Ontario Pipeline Landowners Association*
Ontario Coalition Against Poverty
Union Gas Limited and Centra Gas Ontario Inc.*

Parties Substantially Supporting the Dissent Document

Canadian Industry Program for Energy Conservation*
Canadian Association of Energy Service Companies
Energy Probe
Green Energy Coalition*
Industrial Gas Users Association*
Heating, Ventilation, Air Conditioning Contractors Coalition Inc. Ontario Native Alliance
Pollution Probe

* Letter of Comment Received

APPENDIX B

ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

1998

Ontario
Energy
Board

ONTARIO ENERGY BOARD
GUIDELINES FOR
ASSESSING AND REPORTING ON
NATURAL GAS SYSTEM EXPANSION
IN ONTARIO

JANUARY 1998

CONTENTS

I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report dated August 15, 1996; Final Report dated January 30, 1998).

Portfolio Approach

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion.

Financial Feasibility Analyses

The Guidelines provide the utilities with direction with respect to the structure of their system expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis.

Reporting

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distribution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis.
These reporting requirements are intended to provide the Board and interested parties with sufficient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case.

Customer Connection Policies

Part of the utilities' management of distribution system expansion will be the provision of common customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers.

Environmental Considerations

To ensure that the utilities plan and construct system expansion facilities in an environmentally acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects.

1. SYSTEM EXPANSION PORTFOLIOS

1.1 Investment Portfolio

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs.

The Investment Portfolio will be designed to achieve a profitability index ("PI") greater than 1.0.

1.2 Rolling Project Portfolio

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main.

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio.

2. STANDARD TEST FOR FINANCE FEASIBILITY

The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below.

2.1 DCF Calculation and Common Elements

The DCF calculation for a Portfolio will be based on a set of common elements. For revenue forecasting, the common elements will be as follows:

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer

Attachment Horizon for each project;

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year;

(c) an estimate of average use per added customer which reflects the mix of customers to be added;

(d) a factor which reflects the timing of forecasted customer additions; and

(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component.

For capital costs, the common elements will be as follows: |

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights;

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and

(c) an estimate of the normalized system reinforcement costs.

For expense forecasting, the common elements will be as follows:

(a) gas costs as used in revenue forecasts (excluding commodity costs);

(b) incremental operating and maintenance costs;

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and

(d) municipal property taxes based on projected levels.

2.2 Specific Parameters

Specific parameters of the common elements include the following:

(a) a 10 year customer attachment horizon;.

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers);

(c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity;

(d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs.

3. MONITORING PORTFOLIO PERFORMANCE AND SHORT TERM RATE IMPACTS

3.1 Rates Case Filings

The following information will be filed in each rates case:
Test Year

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI;

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data;

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the:

i) contribution to annual revenue requirement;
ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer class; and
iii) class-specific estimated percent rate and annual average bill increases.

(d) estimates of the NPV and the benefit-cost redo for the Investment Portfolio using a Societal Cost Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilizes' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalizes.

<u>Historic Year</u>

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI;

(b) the aggregate NPV, the total capital, and the portfolio PI for

i) the Rolling Project Portfolio at the end of the historic year;

ii) all completed projects with negative NPVs;

iii) all completed projects with positive NPVs;

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio;

(d) actual expenditures on reinforcement projects; and

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data.

3.2 Ongoing Monitoring Information

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements.

A. Financial Monitoring

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample:

(a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and
(b) the corresponding year 3 customer attachment forecasts and associated revenues and costs.

B. Environmental Monitoring

In consultation with Board Staff, the utilities shall select a set of completed projects and file data on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting acquired. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample:

1. a description of how the project complied with the Board-approved environmental screening, planning, documentation and reporting requirements;

2. a table of significant features, how they were avoided or mitigated, and resulting impacts;

3. a table displaying the concerns raised by affected parties including member ministries of the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns;

4. issues of significance arising from any post-construction monitoring;

5. where alternatives were investigated, a display of alternatives (routes/sites) which show the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen;

6. evidence that all necessary approvals (permits, licences) were obtained; and

7. forecast versus actual costs of the environmental planning.

3.3 Risks of Non-performance

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur:

(a) the utility will be required to provide a complete variance explanation in its rates case and the Board will determine whether or not an acceptable explanation has been provided; and

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

The utilities will maintain a clear set of common Board-approved Customer Connection and Contribution in Aid Policies.

The criteria for contributions in aid of construction for service lines and mains will apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction will take into account the future load growth potential and timing of any such expansion.

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the following:

* Requirements for payment for all, or part, of a customer service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges.

* Requirements for contributions in aid of construction for connection of individual customers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios.

* Requirements for contributions in aid of construction for expansion projects dominated by one or more large volume customers.

5. ENVIRONMENTAL FOR DISTRIBUTION SYSTEM EXPANSION PROJECTS

The planning principles described in the Board's "Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities In Ontario (1995)" shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project.

The utilities shall apply environmental screening criteria to determine when significant features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be applied depending on the impacts expected as determined through the screening process.

Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters, shall identify potential impacts through the screening process and determine the level of planning required. Depending on the significance of the potential impacts anticipated, the planning requirements may involve environmental specialists of the utility, external consultants or other affected parties.

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications.

6. DOCUMENTATION RECORD KEYING AND REPORTING

The utilities will maintain documentation for all projects which are to be included in the Rolling Project Portfolio. A record of the DCF analysis conducted for each project in the Rolling Project Portfolio shall be available for review upon request of the Board. The performance tracking of individual projects shall be as described in Section 3 of these Guidelines.

The utilities will maintain a record of the environmental planning, documentation and reporting requirements associated with all projects and Environmental Reports for those projects deemed to have significant environmental impacts.

For all expansion projects in the Rolling Project Portfolio with a capital cost greater than $500,000 ("major projects") the utilities shall file the NPV and DCF analysis in each rate case and shall keep a record of forecast and actual customer attachments for a period of three years after construction is completed. In addition, the utilities shall also file in each rate case, the NPV and DCF analysis for all major projects planned for the test year. Upon request of the Board, the utilities shall file forecast and actual customer attachments for major projects.

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations.

SCHEDULE 1

DISCOUNTED CASH FLOW METHODOLOGY

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION WITH REASONS

EB-2016-0004

ONTARIO ENERGY BOARD GENERIC PROCEEDING ON COMMUNITY EXPANSION

BEFORE: Ken Quesnelle
Presiding Member and Vice Chair

Cathy Spoel
Member

Paul Pastirik
Member

November 17, 2016

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Appendices:

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1 INTRODUCTION, SUMMARY OF FINDINGS AND DECISION FORMAT

Introduction

This proceeding is a generic hearing convened by the Ontario Energy Board (OEB) to establish a framework within which natural gas service could be expanded to communities in the province of Ontario that are not currently served.

In the 2013 Long-Term Energy Plan, the Government of Ontario signaled that it would look at opportunities to expand natural gas service within the Province to areas that are not currently served. To support the Government's policy objectives, the OEB began meeting with gas distributors, new service providers, consumer groups and other stakeholders to better understand the regulatory barriers, if any, to gas expansion.

In a February 17, 2015 letter to the Chair of the OEB, the Minister of Energy encouraged the OEB to continue to move forward on its plans to examine opportunities to facilitate access to natural gas services to more communities.

On February 18, 2015, the OEB invited parties with the appropriate technical and financial expertise to apply for approvals for expansion projects, and to propose, within those applications, the regulatory flexibility or exemptions from current requirements that would facilitate these expansions.

Union Gas Limited (Union) filed an application (EB-2015-0179) in July 2015 for approval to provide natural gas service to a number of unserved communities. Union proposed various alternative approaches to recover the revenues required to fund the capital investment required for these expansions, as they are uneconomic using the existing criteria.

In that application the OEB determined that it would first address the proposed funding mechanism, leaving the related leave to construct applications to be heard once a funding mechanism was established.

At the Pre-Hearing Day on December 18, 2015, a number of parties submitted that the issues in the proceeding and the evidence they proposed to file had broader implications and raised public policy issues. The OEB agreed that the issues raised by the parties were common to all gas distributors and new entrants seeking to provide gas distribution services and accordingly established this generic proceeding.

The OEB adjourned Union's application (EB-2015-0179) with the intention of proceeding with it at the conclusion of this generic hearing. The OEB has issued a procedural order for Union's application concurrent with this Decision.

Summary of Findings

Natural gas service is widely available in many parts of Ontario. It is used extensively to heat homes and businesses, and to fuel many industrial applications. Having access to natural gas will often lead to economic benefits, primarily through reduced fuel costs.

Despite the benefits of natural gas, there are still areas of the province that are not being served. In most cases, these are rural and/or remote communities where there are challenges to building out natural gas infrastructure (primarily pipelines) in an economic way. Although the costs of building the infrastructure can be high, so too can the benefits of having access to natural gas. Despite some of the high up-front costs, it appears that for many communities the economic benefits of having natural gas would greatly outweigh these costs.

In spite of this, many of these communities are not being served under the existing framework. Clearly, there are barriers. The purpose of this proceeding is to assess what these barriers are, and to determine what steps, if any, can be taken to overcome them.

At the OEB's invitation, parties proposed a variety of measures that could lead to expanded gas service. These included surcharges for new customers, financial contributions from municipalities, subsidies provided by existing customers, funding from other levels of government, and competition in the form of new entrants to the gas distribution business.

Under the existing framework, utilities are generally only permitted to expand to communities where the incremental revenues that will be generated from the expansion will, over time, cover the costs of the expansion. If the revenues do not recover the costs over time, an up-front payment in the form of a capital contribution will be required from new customers. This ensures that existing customers do not have to pay higher rates to subsidize the extension of natural gas service to new communities. This is known as the “benefits follow costs” principle, and has been used for many years in Ontario and other jurisdictions.

Utilities are also required to charge customers that are in the same rate class the same rate. Under the existing framework, for example, it is not open to a utility to charge customers in a potential expansion community a higher rate than existing customers in the same rate classification. The result of this is that many communities are not served because, at existing rates, the revenues from the expansion would not cover the costs. This prevents expansion to communities even where the economic benefits of expansion to the community greatly exceed the costs of expansion, even at a higher rate.

The OEB has determined that this is one of the primary barriers to expansion, and it will therefore allow utilities to charge “stand alone” rates to new expansion communities. The evidence shows that for many communities a higher gas distribution rate would be more than offset by the savings these customers would realize over time by converting to natural gas. This is true even when one considers the costs of conversion, such as a new or modified furnace.

Where funding from municipal, provincial, or federal sources is available, the OEB expects the utilities and the communities to use this funding to lower the cost to customers. The OEB will also make changes to its processes relating to the granting of Municipal Franchise Agreements and Certificates of Public Convenience and Necessity that it expects will facilitate competition for gas distribution to new communities.

The other chief measure proposed to enable more expansions was a subsidy from existing customers. The OEB has determined that this is not appropriate. As noted above, the economic benefits of expansion to many communities are much greater than the costs. This approach would also distort the market to the detriment of existing energy services that compete with gas, such as propane, and new gas distributors who do not have an existing customer base. Under these circumstances, it would not be appropriate to require existing customers to pay for a portion of any expansion. The communities that receive the benefit will be the ones paying the costs.

Decision Format

The format of this decision is intended to provide the OEB's determinations and present a record of the proceeding in a concise and yet comprehensive fashion. Given the diverse interests represented in this hearing and the broad range of issues, a large record of evidence and submissions has been created. As explained later in the Issues section, the significance of some issues is either diminished or has been eliminated due to the OEB's determinations on some pivotal matters. A summary of the submissions on all of the issues identified at the commencement of the proceeding is attached as Appendix C.

The numbered sections that follow provide:

2. An explanation of the process that was followed in the hearing and a description of the types of interests that were represented;
3. A brief high-level general background on gas expansion and required approvals;
4. An identification of the issues dealt with in this decision and an explanation of why the number of issues has been reduced;
5. A summary of the proposals submitted by Union, Enbridge Gas Distribution Inc. (Enbridge) and the evidence submitted by other parties; and
6. The OEB's findings on the issues.

2 THE PROCESS

The OEB decided to adjourn Union's application until the completion of this generic hearing. Union's application and evidence were made part of the record of this proceeding and intervenors in Union's proceeding were deemed to be intervenors in this proceeding.

The OEB issued a Notice of Hearing for this proceeding on February 5, 2016. In Procedural Order No. 2, issued on March 9, 2016, the OEB provided an Issues List for the proceeding and set out the process for filing evidence and discovery of that evidence. The Issues List is attached as Appendix B.

The OEB held an oral hearing from May 5, 2016 until May 13, 2016. A number of parties called evidence.

The OEB issued Procedural Order No. 3 on May 30, 2016 providing for two rounds of submissions by all parties with specific requests for responses to certain matters. Procedural Order No. 3 is attached as Appendix D.

Numerous parties representing a broad range of interests participated in the hearing. These included:

- Union and Enbridge, existing gas distributors with specific expansion proposals;
- Municipalities interested in gas expansion by Union and/or Enbridge;
- EPCOR, a distributor new to Ontario which proposes to serve areas in South Bruce;
- The South Bruce municipalities, proposed to be served by EPCOR, and Greenfield Specialty Alcohols Inc., a potential EPCOR customer
- Canadian Propane Association, Parkland Fuel Corporation, Ontario Geothermal Association which do or may provide other fuels in areas not currently served by natural gas
- Representatives of residential, commercial, industrial and institutional ratepayers,
- First Nations communities in southern and northern Ontario

The full list is attached as Appendix A.

3 BACKGROUND

The natural gas distribution system has developed and grown over many decades in Ontario. Many factors contribute to the placement and growth pattern of the system. The economics of expansion are based primarily on the proximity of a proposed expansion area to the existing distribution and transmission system and the potential number of customers that may use the system. These two components drive both the cost to expand the system (distance adds costs) and the potential for revenues to offset those costs (more customers, more revenue).

The OEB devised a method of assessing the economics of distribution expansion projects in 1998 in a process known as E.B.O. 188.
E.B.O. 188 describes the economic test that is to be used to ensure that on an overall basis, system expansions are not subsidized by existing customers.

At a high level, the E.B.O. 188 “test” is simple. The revenues from the proposed expansion are forecasted using the utility’s existing rates. These revenues are measured against the costs of the expansion. On an overall portfolio basis, the revenues from the expansions must be at least as high as the costs. This ensures that existing ratepayers do not subsidize the costs of new expansion customers.

A key feature of the E.B.O. 188 assessment tool is that a portfolio of projects can be aggregated and tested as a whole. This allows the natural gas distributor to propose a portfolio of expansion projects, some that are more costly and others that are less so. However, no one project can proceed unless, using existing distribution rates and forecasted attachments, it will recover at least 80 percent of the costs over the life of the project. The entire portfolio of projects will have to at least recover its costs.

In cases where less than 80 percent of costs of an individual project are expected to be recovered, the natural gas distributor may ask new customers for a contribution in aid of construction to offset the additional costs and limit the amount of the subsidy from other customers.

E.B.O. 188 has generally been very successful in facilitating the expansion of natural gas service. Both Enbridge and Union connect tens of thousands of new customers to their systems every year. As noted above, however, it has been much less successful in encouraging expansion to rural or remote areas.

There are a number of other existing regulatory requirements for expansion of the system:

Municipal Franchises Act

Before a utility can provide gas distribution service, it must comply with the provisions of the Municipal Franchises Act. These include the entering into of a franchise agreement with the municipality and having it approved by the OEB, and obtaining a Certificate of Public Convenience and Necessity for the construction of facilities from the OEB.

The Municipal Franchise Agreement deals primarily with the relationship between the municipality and the gas distributor with respect to such issues as the use of the municipal road allowance for the construction of the facilities. It does not grant exclusive rights to the gas distributor, though in most cases only one utility will hold a franchise agreement for any particular area. As a result of municipal reorganizations and consolidations, different parts of some municipalities are served by different gas distributors.

In some areas without gas service, there is already a franchise agreement and a Certificate of Public Convenience and Necessity as historically these often apply to an entire municipality even if a portion of it has not received gas service. In these cases, the OEB's practice has been not to require any further approvals for the incumbent distributor under the Municipal Franchises Act to expand the gas system in a municipality.

Leave to Construct

Construction of a natural gas distribution line that meets any of the following criteria requires that a gas distributor apply for a leave to construct and secure approval from the OEB (OEB Act section 90):

- The diameter of pipeline is 12 inches or greater
- An operating pressure greater than 2,000 kilopascals
- The cost of the project is greater than $2,000,000
- The length of the pipeline exceeds 20 kilometers

E.B.O. 134

E.B.O. 134 directs all natural gas distributors on the manner of assessing the feasibility of natural gas **transmission** projects. In cases where the costs of these expansion projects exceed an amount covered by the existing rates, other public interest factors may also be considered.

4 ISSUES

The Issues List established by the OEB in advance of the hearing provided a useful framework for organizing the proceeding. Some of the issues identified in advance were provisional in nature in that their relevance depended on OEB findings on other issues. For example, the question of whether or not the OEB has the authority to establish a universal fund to subsidize expansion projects is moot if the OEB determines that such a fund is not required or not appropriate irrespective of its authority.

This decision addresses the issues that remain pertinent in light of the determinations on key matters such as those highlighted above.

5 PROPOSALS AND OTHER EVIDENCE

This section provides summaries of the proposals by Union and Enbridge and the evidence of other parties.

Union and Enbridge, the existing distributors who participated actively in the proceeding, made a number of proposals that would overcome the constraints imposed by E.B.O. 188.

They involved contributions from the following sources: the new customers, municipalities where these customers are located, and existing customers of their systems.

Union proposed the following framework:

- Customers who attach to the system would pay a Temporary Expansion Surcharge (TES) rate of \$0.23 / m^3 for 4 to 10 years, depending on the economics of each project. Union proposed not to implement a TES for contract customers.

- Municipalities would contribute through an Incremental Tax Equivalent (ITE) mechanism which is in effect a refund of the additional property tax revenue it will receive as a result of the installation of the new gas distribution pipelines. Union proposed that the term of the ITE would match the term of the TES.

- All other Union customers would contribute through a subsidy as the proposed projects do not recover the required revenue even with the TES and ITE. Union further proposed that it also be exempt from E.B.O. 188 guidelines. Union proposed that individual community expansion projects be allowed to proceed at a Profitability Index (PI) of 0.4 or greater, and that the community expansion projects be exempted from E.B.O. 188 Investment Portfolio and Rolling Project Portfolio requirements. The estimated bill impact for existing ratepayers if the 29 community expansion projects Union has identified were to proceed, ranges from \$1 to \$4 per year for the average residential customer in Union North and Union South. Union also proposed to limit the cumulative rate impacts on existing customers to a maximum of \$2 per month (\$24 per year) for all system expansion projects it undertakes.

Enbridge proposed the following:

- A System Expansion Surcharge of $0.23/m^3 (similar to TES proposed by Union) for up to 40 years or until the project achieves a PI of 1.0. Enbridge proposed to collect the surcharge from all customer classes in the expansion area.

- An ITE proposal similar to Union's with a maximum term of 10 years.

- Enbridge proposed the creation of an additional portfolio specifically for community expansion projects. The Community Expansion Portfolio would be managed so that it maintained a PI of 0.5 or greater for all community expansion projects.

- Enbridge also proposed an exemption from E.B.O. 188 that would allow individual community expansion projects to proceed at a PI of less than 0.8. Enbridge did not propose a minimum threshold PI for individual projects.

Enbridge's evidence was that it could complete approximately 39 community expansion projects using this framework, providing natural gas service to approximately 16,000 homes and businesses in the first 10 years at a total capital cost of approximately $410 million. The estimated existing ratepayer impact associated with the proposal over the first ten years ranges from a rate reduction of $0.16 to an increase of $3.98 per year with the cumulative bill impact reaching a maximum of $10.39 per year in the ninth year for existing customers.

Evidence of other Parties

<u>EPCOR Utilities Inc.</u>

EPCOR Utilities Inc. (EPCOR), as a potential new entrant, filed expert evidence of Adonis Yatchew.

EPCOR recently signed franchise agreements with the municipalities of Arran-Elderslie and Kincardine and the Township of Huron-Kinloss (collectively referred to as South Bruce) to provide natural gas distribution service. Union also included these municipalities in its proposed 29 community expansion projects.

In his evidence, Dr. Yatchew provided an outline of the benefits of natural gas expansion and competition for franchise areas. Dr. Yatchew noted the benefits of competition including potential lower capital costs and innovative business models. Dr. Yatchew also discussed how regulatory agencies in other jurisdictions addressed competition for gas services and the outcome of the initiatives.

EPCOR also recommended the establishment of an expansion reserve fund that would require contribution from all natural gas distributors to fund expansion projects in the Province. EPCOR was of the view that because new entrants do not have an existing customer base to subsidize projects, they would be at a disadvantage if incumbents were allowed to use subsidies from existing customers. An expansion reserve fund would level the playing field according to EPCOR.

EPCOR supported certain aspects of Union's proposal including that potential new customers, municipalities and existing customers should contribute to system expansion costs. However, EPCOR was of the view that the proponent should also be willing to contribute to project costs and should not be shielded from all financial risks associated with the projects.

South Bruce

South Bruce filed three reports as evidence. The first report titled, "The approach and competitive solicitation process undertaken by the Municipalities to facilitate the expansion of natural gas services to Southern Bruce County" was prepared by Dr. Lawrence Murphy. The report outlined the process pursued and exploratory work undertaken by the municipalities and their advisors over a 5-year period that ultimately resulted in the selection of EPCOR as the preferred provider of natural gas services. The second report titled "Mechanisms for Supporting Natural Gas Community Expansion Projects", prepared by Elenchus Research Associates Inc., reviewed the evolution and policy context of the existing economic feasibility framework used by the OEB to assess and approve distribution system expansion projects. The report also discussed approaches used in other Canadian jurisdictions and other Canadian sectors to address the challenge of meeting the needs of unserved communities at affordable rates.

The third report titled, "Rural Rate Assistance as a ratemaking or rate recovery approach which the OEB should consider when assessing the Generic Hearing issues related to natural gas system expansion" was prepared by Bruce Bacon of Borden Ladner Gervais LLP. The report provided a brief history of rural rate assistance for electricity services in Ontario and how the assistance was funded and provided to eligible rural residential customers.

Canadian Propane Association

The Canadian Propane Association (CPA) filed evidence that outlined its position with respect to the OEB's authority to subsidize natural gas system expansion. The report noted that the OEB was an economic regulator and economic development or facilitating societal benefits was not its role. The report further claimed that natural gas system expansion was already occurring in rural and remote communities in Ontario without subsidization.

Parkland Fuel Corporation

For Parkland Fuel Corporation (Parkland), Kalyan Dasgupta and James F. Neiberding provided comments on some of the economic issues in this proceeding. The report concluded that existing ratepayers should not be required to subsidize expansions of the natural gas system into unserved areas if they do not produce broad societal benefits. These costs should ideally be borne by all taxpayers rather than just utility ratepayers. The report further noted that cross-subsidies that distort the price of natural gas throughout the Province are more distortionary relative to alternate policies, and fare poorly in terms of providing the right economic incentives for efficient investment by incumbent utilities and alternate fuel service providers. Parkland also filed in evidence an affidavit by Gary Highfield, a director of the company, outlining the competition for fuel in Ontario and the impact subsidized natural gas would have on Parkland's business.

Northeast Midstream LP

Northeast Midstream LP (Northeast) provided expert evidence of Christopher Gulich on the costs that a local gas distribution company should consider when evaluating a service territory expansion not proximate to its existing infrastructure.

Greenfield Specialty Alcohols Inc.

Greenfield Specialty Alcohols Inc. (Greenfield) is Canada's leading specialty alcohols producer. Greenfield's evidence dealt with its Tiverton Industrial Alcohol distillery located in the Municipality of Kincardine and its need for natural gas in the facility. Greenfield supported the principle of subsidization to promote natural gas expansion and advocated for a competitive, open and transparent process to facilitate the provision of natural gas service in communities across Ontario.

Ontario Geothermal Association

The Ontario Geothermal Association (OGA) provided expert evidence of Dr. Stanley Reitsma, David Hatherton and Martin Luymes. The evidence provided technical information about geothermal systems and explained the cost and environmental benefits of using geothermal energy for producing space/water heating and cooling. The evidence also provided specific comparisons to natural gas and the reductions that can be achieved in greenhouse gas emissions as a result of converting to geothermal systems.

Anwaatin Inc. and Mocreebec Eeyoud

Anwwatin Inc. (Anwaatin) which represents six First Nations communities and Mocreebec Eeyoud (Mocreebec) filed similar evidence. The evidence described the energy poverty situation in First Nations communities and the immediate need for low cost energy solutions in these communities. The evidence supported the establishment of a Universal Service Fund that would require contribution from all natural gas customers and further outlined the mechanics of such a fund. The proceeds of the fund would be used to expand natural gas service to communities that are not currently served.

NOACC Coalition

The NOACC Coalition is an alliance of Northwestern Ontario Associated Chambers of Commerce, Northwestern Ontario Municipal Association and Common Voice Northwest. The Coalition’s evidence described the constraints of the existing regulatory framework on expanding natural gas service to northern Ontario and outlined the benefits of expanding gas service to northern communities.

Vulnerable Energy Consumers Coalition

Vulnerable Energy Consumers Coalition (VECC) provided evidence of George Hariton and Tom Ladanyi. The evidence reviewed the evolution of the OEB’s current natural gas system expansion policy and described the subsidy model used in the telecommunications industry. The report also opined on the jurisdiction of the OEB to establish a universal fund that would support system expansion projects with contributions from all natural gas customers.

All parties that filed evidence provided testimony at the oral hearing with the expert witnesses available for cross-examination. Norfolk County and the Municipality of East Ferris also submitted evidence, in the form of letters supporting Union's proposal to expand gas in communities which do not currently have access to it. There was no cross-examination of these two municipalities.

6 OEB FINDINGS

Expansion Financing and Approvals

The E.B.O.188 guidelines provide for economic growth of the natural gas distribution system with limited cross subsidies to some projects within a portfolio in any given year. The proposals put forward by Enbridge and Union seek, amongst other things, to increase the amount of subsidization that would occur as well as introduce other mechanisms that would fund the expansion projects.

Most of the submissions in this proceeding relate in some way to whether there should be changes to E.B.O. 188. Other fuel providers and some ratepayer groups were opposed to changes to the E.B.O. 188 guidelines, primarily as they relate to changes to the minimum PI threshold. They argued that existing customers should not be required to fund uneconomic expansions into new communities where the costs of doing so considerably outweigh the benefits. Their position was that the E.B.O. 188 guidelines were established to ensure that existing customers are held harmless from the cost of new connections and that this important objective should be maintained. Some parties observed that subsidizing community expansion would distort the competitive market for other energy services (propane, geothermal etc.) in those communities as they would not be able to compete with subsidized natural gas service.

The potential savings to the residents of the proposed expansion areas that would result from using natural gas for home heating are substantial. In most cases, the savings outweigh the cost of the proposed expansion. The resulting savings to homeowners would cover the cost of the expansion well within the life expectancy of the infrastructure. The proposed exemptions from the E.B.O. 188 guidelines and additional subsidization are intended to overcome upfront investment barriers that homeowners will face when switching to natural gas and not the long-term economics of switching to natural gas.

The OEB heard evidence that customers in the new communities will realize substantial savings over the long term from converting to natural gas. Under Union and Enbridge’s proposal (which includes a subsidy from existing ratepayers), residential customers converting to natural gas from oil, wood, electric or propane would realize average annual savings of over $1,600. With the inclusion of the proposed expansion surcharge, the average annual savings are approximately $1,100 for both utilities’ (Union and Enbridge) residential service customers.

Even with no subsidy at all there are substantial savings over a 40-year period. The resulting Net Present Value of customers' net fuel savings from all 39 projects proposed by Enbridge is approximately $357 million. This means that the new community expansion customers of Enbridge are projected to save approximately $357 million over a 40 year period after accounting for the annual charges in rates and the cost to convert their equipment. Similarly, the new community customers of Union are projected to save $313 million over the 40 years with respect to the 29 community expansion projects. Consequently, some parties questioned the need for expansion customers to receive any subsidy. However, Union and Enbridge argue that expansion cannot be accomplished without changes to the existing E.B.O. 188 framework; otherwise the communities seeking natural gas would have already been connected.

The OEB does not consider it appropriate or necessary to subsidize projects that result in sufficient savings to customers to cover the costs of the projects. What is required is a method of overcoming the upfront investment hurdle.

E.B.O.188 guidelines function well in the natural growth driven expansion of the distribution system at the edge of the serviced areas. These areas often do not require large investments, and in the case of new development, there is an identifiable party available to pay any contribution that may be required.

The guidelines function less effectively when applied to expansions to discrete new areas which are not contiguous to the existing distribution system.

The requirement for exemptions from E.B.O. 188 is due to the failure of the economic tests using existing rates for the various rate classes in the expansion area. Altering the thresholds within the existing guidelines and obtaining direct funding from existing customers to accommodate the shortfall in revenues would not be required if the expanded system had stand-alone rates intended to cover the cost of the expansion.

The OEB agrees with the submissions of South Bruce and CCC that support the establishment of stand-alone rates. The OEB considers it appropriate to allow proponents to apply for rates that are geared towards the costs of the individual projects, or groups of projects where they have similar cost drivers. There is no need to modify the parameters or depart from the principles embodied in E.B.O. 188 to facilitate expansion projects.

The OEB notes that while “postage stamp” rates have been the basis for assessing the economics of expansion projects in the past, these postage stamp rates already vary within the province, depending on the distributor. Union itself has two rate zones, Union North and Union South. The rates in Union North are somewhat higher, to reflect the higher cost of gas distribution in that area. Each set of rates reflects the average costs of providing service in the area covered by the rate zone. The economics of an expansion in an area where there is more than one potential supplier can therefore vary depending on which rate is applied.

This approach would allow existing distributors and new entrants alike to propose new rate zones that would cover the costs of serving expansion areas. If there is more growth in these areas than initially anticipated, over the long term the rates will be lower. They may eventually be harmonized with a utility’s other distribution rates, or may continue as separate rates as with Union North and Union South.

The initial rates required to finance the expansion would be part of the economic test information required for the leave to construct required for the expansion. These could all be considered at the same time as the Certificate of Public Convenience and Necessity (Certificate) and the approval of a franchise agreement, if these are required.

With the ability to propose new rates there is no need to test the profitability of projects against existing rates. Proposals will need to be self-financing and therefore there will be no risk to existing ratepayers. This would also be fair to suppliers of other fuel as one fuel choice will not be subsidized, and to new entrants who do not have an existing customer base to subsidize expansions.

Contiguous expansion of the existing system with development on the edge of serviced areas would continue to be managed under the E.B.O. 188 framework. Demarcation criterion will be needed to separate those projects that would appropriately be dealt with in that manner rather than applying for new rates.

A framework that employs new rate zones would also facilitate the entry of new participants and allow for competition. This would be accomplished by considering the proposed rates for a potential service area in a leave to construct hearing. Alternative competing bids could be considered by the OEB at the same time. The awarding of Franchise rights and Certificates can be considered in conjunction with the Leave to Construct application putting all on a level playing field.

The OEB notes that neither Franchise Agreements nor Certificates are exclusive. While it would be inappropriate to have more than one gas distribution system serve any specific location, there are a number of unserved areas for which Certificates have been issued. The practice in the past appears to have been to issue a Certificate for an entire municipality even if only a portion would be served. In the OEB's view, where a Certificate has been issued for an area but there is currently no distribution service, another distributor can apply for a Certificate to serve that area. This may result in competing bids.

The issue of advancing upstream system expansion and enhancements should be considered in every case where they are shown to exist. The cost of upstream enhancements that any project would bear must be the same regardless of the utility proposing the expansion. This will allow for proper comparison of competing bids, again leveling the playing field.

Any leave to construct application for community expansion projects should provide separate costs for the transmission and distribution segments of the project as well as any upstream reinforcement costs. This information would also allow the OEB to better evaluate alternatives including LNG or compressed natural gas.

Competing utility companies would be incented to provide rates favourable to customers in order to be selected as the preferred proponent of the expansion project. The selected proponent would then be incented to maintain low rates in order to be attractive to potential customers which would in turn should increase its margins. A minimum rate stability period of 10 years (for example) would ensure that rates applied for are representative of the actual underpinning long-term costs. The utility would bear the risk for that 10-year period if the customers they forecast did not attach to the system. At present, once an expansion is approved, the utility bears little long-term risk if its forecasts were overly optimistic, or its actual costs higher than expected. The cost is absorbed into rates and paid for by other ratepayers.

As mentioned above the rate stability feature of the framework introduces a discipline that significantly reduces the need to scrutinize a proponent's projected revenues. As the rates will be stand-alone and designed to cover the costs of the proposed expansion the existing customers will be held harmless. Overstated costs would lead to overstated rates and where there is competition for the approval, a proponent will risk not being chosen. Where there is no competition, a proponent will still be incented to have as low a rate as it can afford to encourage customers to connect and provide the return on the proponent's investment during the rate stability period. The proponent will also have to obtain approval to adjust rates beyond the rate stability period.

It may be that these remote system expansion projects would eventually employ versions of E.B.O.188 for expansions in those areas. The trade-offs between direct cost causality costing and postage stamp rates occur in all distributed network systems that serve multiple customers. The OEB has determined that the principles adopted in E.B.O.188 facilitate expansion of contiguous systems in a fair and equitable manner. The same principles will be applied in new rate zones that have been developed with stand-alone rates.

Other sources of funds from government sponsored programs or municipal contributions can continue to be used as capital contributions as they are now, or used directly to offset homeowner conversion costs. The OEB will be considering the ultimate costs to be borne by ratepayers in its comparative assessments of multiple proposals. An incumbent utility with existing rates may still propose to collect a surcharge over and above those rates to make up for the shortfall in revenues to cover the cost of the expansion. This form of funding does not depart from the mechanics or principles embodied in the E.B.O. 188 assessment. However, in situations where surcharges are proposed, distributors should ensure that the level of revenues generated through the surcharge (in addition to base rates) can readily be compared to the revenues that would otherwise be collected from a stand-alone rate that might be charged by another distributor.

It is possible that in some of the communities prospective customers are hesitant to commit to natural gas conversion due to the cost of converting their heating equipment to natural gas. The OEB believes that the Government's Natural Gas Access Loans and Grants program could be an effective tool to support conversion costs or capital contribution amounts.

The OEB expects to refine the mechanisms and features of the framework described here through the adjudication of the initial applications and will seek submissions from applicants and affected parties on implementation matters within those applications.

Liquefied Natural Gas (LNG)

In its application, Enbridge identified a subset of 19 communities that it intends to serve using LNG. Enbridge proposed to recover the cost of LNG (i.e. the “all in” commodity cost, including liquefaction) from all customers through the company’s gas supply plan. Northeast Midstream supported Enbridge’s approach while OEB staff and CPA opposed it. OEB staff noted that requiring all customers to pay for the cost of LNG supply would not be fair to existing ratepayers as they are not causing the incremental costs. OEB staff argued that communities that are served using LNG should pay the costs to serve them.

CPA argued that LNG trucks would be essentially competing with propane trucks to serve the same customers. If subsidies were provided to LNG, then the propane business could be severely impacted. CPA submitted that the fact that propane delivery trucks and distribution centres can profitably operate without a subsidy suggests that LNG delivery trucks should also be able to operate without a subsidy.

The OEB agrees with OEB staff and the CPA with respect to the cost allocation of providing LNG. The assessment of the economics of the use of natural gas in a community should include the discrete upstream costs incurred to provide for the delivery of the gas. This holds true whether the costs pertain to pipes, trucks or liquefaction processes.

Contribution from Municipalities

Union and Enbridge proposed a contribution from the municipalities known as the ITE. The municipalities that would agree to the ITE contribution would collect the municipal taxes from the utilities and rebate back the value of incremental property taxes back to the utilities.

Although none of the parties objected to the requirement of an ITE contribution, OEB staff and School Energy Coalition (SEC) proposed to increase the term of the ITE contribution from 10 years to 20 and 40 years respectively.

The OEB agrees with South Bruce that the ITE contribution should be voluntary and not a mandatory requirement. The OEB does not have the jurisdiction to require municipalities to make a contribution in order to improve the economics of a project. However, if the municipalities agree to make a voluntary contribution to the economics of a project, the OEB will assess the terms of the agreement in the individual community expansion applications. It is up to the individual applicant and the municipality to agree on the quantum, duration and mechanics of such a contribution.

Pass-through of Revenue Requirement Related to Community Expansion Projects in Rates during Incentive Regulation Period

Union and Enbridge are currently operating under an Incentive Regulation (IRM) framework until the end of 2018. Union and Enbridge have proposed a capital pass-through mechanism to recover capital costs related to community expansion projects. Union noted that the investments are not “business-as-usual” and therefore cannot be managed within Union’s OEB approved capital budget under the 2014-2018 IRM framework. Union further noted that in the absence of approval to recover the revenue requirement related to the capital investments, it would be unable to commit the incremental capital required to facilitate expansion to the communities[1].

Enbridge submitted that irrespective of the ratemaking framework adopted by the OEB to facilitate community expansion, it should allow for the recovery of the associated revenue requirement in rates prior to the end of the current incentive regulation plan.

Several intervenors have argued that Union should not be allowed recovery of the revenue requirement related to community expansion projects in rates prior to the end of the current IRM term as it would require a change to the settlement agreement requiring consent of all the parties to the agreement.

Given the OEB’s determination with respect to stand-alone rates, it is preferable to consider the matter of the revenue requirement recovery in the context of individual proposals and not on a generic basis. The OEB will want to determine (among other things) if Union and Enbridge’s proposals negatively impact existing customers whose interests are protected by the settlement agreement. That would best be done in the context of a specific proposal that reflects the OEB’s determinations in this hearing with respect to stand-alone rates.

[1] Union Evidence in EB-2015-0179, Exhibit A, Tab 1, Page 33

Facilitation of Competition

The Municipal Franchise Agreement (MFA) is an agreement between a municipality and the gas distributor that outlines the terms and conditions of access to municipal infrastructure by the gas distributors. The MFA must be submitted to the OEB for approval under section 9 of the Municipal Franchises Act. With the input of municipalities, the OEB has developed a Model Franchise Agreement that provides a template to guide natural gas distributors and municipalities as to the terms and conditions the OEB generally finds reasonable under the Municipal Franchises Act.

Prior to commencing work to supply gas within a municipality, the gas distributor must apply to the OEB for a Certificate. Depending on the infrastructure proposed to be built, the gas distributor requires a leave to construct approval from the OEB under section 90 of the Ontario Energy Board Act.

Union and Enbridge submitted that the OEB should not review or change the existing form of the MFA or the corresponding approval process. Union in fact stated that the OEB should re-affirm its expectation that the current MFA should continue to be adopted on a consistent basis across the province.

Union argued that the current MFA does not impose any specific barriers to expansion. Both Union and Enbridge argued that MFAs are not exclusive. A municipality can have multiple franchise agreements with different gas distributors. The existence of a MFA does not create a barrier for other gas distributors to offer their services in a community that is not currently served. Although Union agreed that a Certificate provides exclusive rights to distribute gas to a specific geographic area, Union was of the view that the OEB can review and amend the geographic area covered by a specific Certificate through an application to do so. LPMA suggested that the OEB should consider amending the Certificate to cover only geographic areas actually served by a distributor in order to prevent banking of MFAs and Certificates in order to encourage other distributors to provide service in un-served areas. Union proposed that prior to entering into a MFA, a distributor should be required to inform the municipality of the rates that will be charged and any conditions associated with those rates. Union submitted that this would ensure transparency, especially in cases where there are multiple proponents. In cases where pre-existing approved rate schedules do not exist, Union suggested that the OEB should approve rates prior to approval of the franchise or delay the approval of the franchise until rates are approved by the OEB.

EPCOR and South Bruce argued that municipalities should be free to negotiate agreements that meet the needs of local conditions. South Bruce also urged the OEB to clarify that MFAs are non-exclusive. South Bruce and several other parties also urged the OEB to introduce a sunset clause in the MFA in the event that a distributor fails to construct the approved expansion in the franchise area. South Bruce submitted that the OEB should terminate the MFA after one year unless there is an active and valid Certificate as the current MFA is effective for 20 years regardless of whether the utility constructs the expansion infrastructure within the municipality.

Several parties made submissions on the requirements the OEB should look for in assessing whether to approve new entrants.

They included such factors as:

Operational Capability – Distribution system that is reliable and compliant with regulation, existence of emergency response procedures and technical staff, system integrity program, Gas Supply Procurement etc.

Ability to meet core expectations of the OEB – meet OEB service quality metrics, compliance with Affiliate Relationship Code, ability to deliver demand side management programs and compliance with future government policy mandates (Cap and Trade)

Financial Stability – Capital requirements, credit worthiness, ability to meet certain financial metrics and a financial plan for the specific expansion

Union argued that in order to be fair to existing utilities, the OEB should apply the same criteria and have the same performance expectations of new entrants.

EPCOR argued that competition for franchises can result in lower costs to customers and incent potential distributors to find ways to reduce capital costs or provide innovative offerings.

South Bruce submitted that the OEB should encourage but not require municipalities to hold competitive procurement processes (RFPs, RFQs and RFIs) prior to entering into a franchise agreement. South Bruce disagreed with the submissions of some parties that proposed that the OEB should conduct the competitive procurement process or impose mandatory requirements on competitive procurement.

South Bruce also argued that municipalities are best positioned to represent the interests of local customers and must play an important role in selecting a natural gas service distributor in their communities. While South Bruce agreed that the needs of large users must be considered in any proposal, it suggested that municipalities are in the best position to consider the needs of the community as a whole. OEB staff agreed with Dr. Yatchew, an expert witness called by EPCOR, that the duties and responsibilities to select a party to enter into a municipal franchise agreement should reside with the municipality. However, OEB staff submitted that the OEB could facilitate this process by pre-qualifying a pool of potential proponents that would have the requisite financial and technical experience and expertise to operate a natural gas distribution system. Greenfield supported a competitive process for awarding municipal franchise agreements but submitted that any such process must include consultation with major customers prior to the granting of a MFA in order to ensure that the proposed options are efficient and effective.

OEB Findings

The approval of municipal franchise agreements predates the establishment of the Ontario Energy Board. MFAs for the distribution of gas were first introduced in Ontario around the turn of the last century, although a majority of them were established after 1957 when Ontario started receiving natural gas from western Canada and large scale gas distribution became possible.

MFAs were approved by the Ontario Fuel Board under the Ontario Fuel Board Act, 1954. The Ontario Energy Board Act 1960 created the Ontario Energy Board as a successor to the Ontario Fuel Board. The OEB was authorized to set just and reasonable rates for the sale and storage of gas and to make orders granting leave to construct pipelines for the transmission of oil or gas pipelines, and also approve municipal franchise agreements.

Prior to 1988, franchise agreements between municipalities and utilities were negotiated between the parties on an individual basis. In November 1985, the OEB held a generic hearing to provide guidance on issues frequently arising in franchise agreements. It released its report (E.B.O. 125) in May of 1986. In its report, the OEB recommended the creation of a Municipal Franchise Agreement Committee to develop a Model Franchise Agreement.

The Association of Municipalities of Ontario (AMO) developed the Model Franchise Agreement in consultation with the gas industry and the original model was approved by the OEB in 1987. A revised agreement negotiated between AMO and the gas industry was approved by the OEB in early 2000.

The MFA is essentially an operating agreement that outlines the terms of access to municipal infrastructure (road allowances etc.), sharing of costs and restoration requirements. The OEB agrees with the views of some parties that no changes are required to the existing MFA as it has been developed after negotiations between municipalities and gas distributors and has worked well for both parties over the years.

The MFA is not a selection tool to identify the most appropriate or least cost distributor and the OEB believes that there are other approaches to encourage competition for franchises. Moreover, a municipality can have multiple franchise agreements involving more than one distributor. The OEB therefore finds that revising the MFA will not add additional value or accomplish the goal of encouraging new entrants to provide gas distribution services in communities that do not have access to natural gas.
The OEB however believes that certain changes are required to facilitate the review of applications for providing gas expansion services in unserved communities and to enable competing proponents to present their proposals before the OEB.

EPCOR has alleged that incumbent utilities are banking franchise agreements that prevent new entrants from offering gas distribution services. The OEB does not believe that this is the case as a municipality is permitted to enter into franchise agreements with more than one distributor. The Municipal Franchises Act allows the Board to issue a Certificate to a utility to serve a “municipality”. There is nothing in the Municipal Franchises Act that ensures that the Certificate gives the utility exclusivity (i.e. its monopoly). The Municipal Franchises Act does not appear to prevent the Board from issuing multiple Certificates for the same municipality. As a result of municipal reorganizations and amalgamations since Certificates were issued, there are several municipalities that have Certificates for more than one utility. These typically describe a geographic area within the municipality. The OEB agrees with Union and Enbridge that they can be amended. This seems to be an appropriate approach to allow new entrants in areas where there is currently no service. One of the issues to be determined by the OEB at the time of the approval of the new Certificate will be the geographic boundaries within which each utility can operate, based on a rational future expansion of the distribution system.

The OEB agrees with the submissions of Union and Enbridge that information regarding proposed rates and resulting rate impacts are critical to evaluate any expansion proposal. However, such information cannot be assessed in the franchise applications and are more appropriate in either a leave to construct or a rate setting application. The OEB has therefore determined that for any community expansion proposal under the OEB's alternative framework, a review of the proposed rates will be required prior to approval of the franchise and Certificate. This will allow the OEB to review pertinent information regarding the proposal including forecast attachment rates, cost allocation, rate design, pipeline route and system reinforcement plans prior to approval of the franchise agreement and Certificate. This approach will also allow proponents to compete for the franchise if they wish to do so. The OEB will entertain multiple applications and approve the proposal that best meets the needs of the community and ratepayers.

Some parties have suggested that the OEB should keep a registry of existing Franchise Agreements and a list of all potential companies that may be interested in serving expansion communities on its web site. The OEB does not believe this is required under its proposed approach. The OEB will publish the leave to construct notice and any proponent that is interesting in presenting its own proposal to the OEB can intervene or file its own application.

Impact of Cap and Trade

On February 24, 2016, the Ontario Government introduced new legislation on climate change. The proposed *Climate Change Mitigation and Low Carbon Economy Act* provides for the design of a cap and trade program, which will put a limit on the amount of greenhouse gases (GHG) that businesses, institutions and households can emit and will put a price on carbon including natural gas. The Government also introduced a Five Year Climate Change Action Plan in June 2016 that provides a roadmap for reducing GHG emissions, and measures to invest the proceeds from the cap and trade program to accelerate the development and use of clean technology by businesses and homeowners.

OEB Findings

The OEB believes that the Province's Climate Change Action Plan could have significant implications on the natural gas sector. However, it is not clear how the pattern of natural gas consumption could change in the future and uncertainties still exist with respect to how the Plan may impact the demand profile of natural gas in the medium and long-term. However, the OEB does not need to opine on the overall demand profile of natural gas in Ontario as part of this proceeding or discuss the possible outcomes as it pertains to the natural gas industry. In light of the OEB's determination to not permit subsidies from existing customers, any impact of the cap and trade program can be assessed and considered within the context of individual expansion project applications. The OEB finds that there is no need to require a separate review to assess the impact of the Province's climate change initiatives.

Some parties have argued that there is a risk of stranded assets in the event that the Government's climate change initiatives lead to significant reduction in demand for natural gas, and that it is therefore not prudent to pursue options to encourage the expansion of the natural gas system. The OEB disagrees with the proposition as these risks are no different from those faced by distribution system expansion projects that are being undertaken by the utilities in subdivisions across Ontario or any other projects undertaken by the utility to address supply issues.

The environmental groups have submitted that the utilities should be required to assess sustainable energy technologies for all community expansion projects. The OEB agrees with the position of OEB staff that utilities are primarily in the business of gas distribution and should not be required to provide detailed assessments of alternative technologies such as solar and geothermal as part of the community expansion applications. Parties that wish to address alternative technologies can bring forward relevant evidence in the leave to construct applications. Where practical alternative technologies are more economically feasible than natural gas, including the impact of cap and trade on gas prices, it is unlikely that gas expansion will proceed.

The OEB expects that in the short-term the impact of the cap and trade program on conversion rates is likely to be minimal. While the cost advantage for natural gas will improve versus heating oil and propane, it will diminish marginally in the case of electricity. In the long-term, the impact will likely depend on the carbon pricing mechanism established by the Province. Since each community is likely to have a different profile in terms of the energy mix, the OEB will review attachment forecast in the individual community expansion applications.

Government Loan and Grants

The Ontario Government through the Minister of Economic Development, Employment and Infrastructure has announced $200 million in Natural Gas Access Loans over two years to help communities partner with utilities to extend access to natural gas. The Government has also made available $30 million in Natural Gas Economic Development grants to accelerate projects with clear economic development potential[2].

The government has not provided any details or the criteria under which these grants and loans will be available. The OEB asked parties to provide comments in their submissions on how to incorporate the loan and grant programs into the economic feasibility analysis and how the disbursement of these funds might relate to the OEB's approval of expansions.

Enbridge and Union both submitted that under their proposed approaches, community expansion projects would be able to proceed without provincial funding. Almost all parties suggested than any government grant should be used as a contribution in aid of construction to reduce the capital cost of projects. They also suggested that loans should be directed to new customers in the communities to defray the costs of converting their heating and water heating systems to natural gas. This would result in higher conversion rates since there would be access to convenient financing.

The OEB believes that any funding available from the government should be used to improve the economics of community expansion projects irrespective of whether they are provided to utilities or individual municipalities, and that loans should be used to assist with financing of conversion of heating equipment. The OEB would consider whether or not the use of grants or loans are consistent amongst proposals when comparing multiple proposals.

[2] February 18, 2015 Letter of the Ontario Energy Board

First Nations

Anwaatin has submitted that the OEB should ensure that the expansion framework arising from this proceeding places a “super-priority” on the expansion of natural gas to energy-poor First Nations communities in an expedient manner.

The OEB notes the importance of the issues raised by Anwaatin at the oral hearing and in submissions with respect to the energy poverty existing in First Nations communities and will respond to any proposal brought forward in the new framework with due consideration to the needs of the intended customers.

Process for Paying Cost Awards

The OEB will use the process set out in section 12 of the *Practices Direction on Cost Awards* to implement the payment of the cost awards. The amounts representing cost awards will not be paid directly by the distributor to the eligible participant. The OEB will act as a clearing house for the payment of all cost awards related to the proceeding.

The costs awarded would be apportioned among rate-regulated natural gas distributors based on the OEB’s revised Cost Assessment Model. Invoices will be issued to distributors at the same time as the invoices for cost assessments are made under section 26 of the *Ontario Energy Board Act, 1998*.

7 ORDER

1. Parties eligible for costs shall submit their respective cost claims on or before November 30, 2016. The cost claims must be filed with the OEB and served on all rate regulated gas distributors including Natural Resource Gas Limited. Parties are reminded not to include any costs related to Union's Community Expansion Application (EB-2015-0179) in the cost claims.

2. All rate regulated gas distributors shall file with the OEB and forward to the intervenors any objections to the claimed costs on or before December 9, 2016.

3. Intervenors whose costs have been objected to, shall file with the OEB and forward to the gas distributors any responses to any objections for cost claims on or before December 16, 2016.

All filings to the OEB must quote the file number, EB-2016-0004 and be made electronically in searchable / unrestricted PDF format through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, **November 17, 2016**

ONTARIO ENERGY BOARD

Original signed by

Ken Quesnelle
Presiding Member and Vice-Chair

Original signed by

Cathy Spoel
Member

Original signed by

Paul Pastirik
Member

APPENDICES

TO

DECISION WITH REASONS

EB-2016-0004

Generic Proceeding on Community Expansion

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LIST OF INTERVENORS

- Advancing Northwestern Economic Development Through Energy Competitiveness Group
- Anwaatin Inc.
- Association of Power Producers of Ontario
- Building Owners and Managers Association Toronto
- Canadian Propane Association
- Chevaliers de Colomb du Conseil 9920
- Chukuni McManus Residents
- Consumers Council of Canada
- Corporation of Norfolk County
- Enbridge Gas Distribution Inc.
- Energy Probe Research Foundation
- Environmental Defence
- EPCOR Utilities Inc.
- Federation of Rental-housing Providers of Ontario
- Greenfield Specialty Alcohols Inc.
- Independent Electricity System Operator
- Industrial Gas Users Association
- London Property Management Association
- Mocreebec Eeyoud
- Municipality of East Ferris
- North Vista Advisors
- Northeast Midstream LP
- Northern Cross Energy Limited
- NOACC Coalition – Northwestern Ontario Associated Chambers of Commerce, Northwestern Ontario Municipal Association and Common Voice Northwest
- Ontario Federation of Agriculture
- Ontario Geothermal Association
- Ontario Petroleum Institute
- Ontario Producers and Storage Companies
- Ontario Sustainable Energy Association
- Parkland Fuels Corporation
- School Energy Coalition
- Six Nations Natural Gas Company Limited

- South Bruce – Municipality of Kincardine, Municipality of Arran-Elderslie and the Township of Huron-Kinloss
- The Corporation of the City of Kitchener
- The Corporation of the Municipality of Dutton Dunwich
- The Corporation of the Municipality of Sioux Lookout
- The Corporation of the Township of Prince
- Township of Augusta
- Township of Edwardsburgh Cardinal
- Township of Perth East
- Township of Warwick
- Union Gas Limited
- Utilities Kingston
- Vulnerable Energy Consumers Coalition

Issues List

EB-2016-0004

1. What is considered a community in the context of this proceeding?

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

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

4. Should the OEB consider exemptions or changes to the E.B.O. 188 guidelines for rural, remote and First Nation community expansion projects?

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

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

    c) What, if any, amendments to the E.B.O. 188 and E.B.O. 134 guidelines would be required as a result of the inclusion of any costs identified above?

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

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

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

5. Should the OEB allow natural gas distributors to establish surcharges from customers of new communities to improve the feasibility of potential community expansion projects? If so, what approaches are appropriate and over what period of time?

6. Are there other ratemaking or rate recovery approaches that the OEB should consider?

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

8. 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?

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

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

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

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

SUMMARY OF POSITION OF PARTIES

Issue 1

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

Union Gas Limited (Union) has defined a community expansion project as a natural gas 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. Enbridge Gas Distribution Inc. (Enbridge) adopted Union's definition in its evidence.

The School Energy Coalition (SEC) accepted the broad definition of community proposed by the utilities but argued that small main extension projects proposed by Union and Enbridge for projects less than 50 potential customers should not be used in municipalities where a municipality does not agree to an ITE contribution. SEC further raised the possibility where utilities could divide a particular community expansion project that does not qualify into small pieces in order to categorise it as several small main extension projects.

OEB staff suggested an addition to the definition to ensure that it is not applied to subdivisions where there is proximate access to natural gas. Accordingly OEB staff suggested adding, "and which cannot be served from the existing distribution system." SEC in reply disagreed with OEB staff's suggestion stating that there was no need to differentiate between existing homes or business based on a distance from a utility's distribution system and the focus should be on relative economic feasibility. South Bruce on the other hand agreed with OEB staff's suggestion.

EPCOR utilities Inc. (EPCOR) in its submission argued that a strict and narrow definition of community was neither necessary nor desirable. The Consumers Council of Canada (CCC) made a similar argument stating that a distinct definition of community was not required under its proposed approach of no subsidies from existing customers. Parkland Fuel Corporation (Parkland) argued on similar grounds suggesting that a definition was not required and expansion proposals should be evaluated on the basis of sound economic and ratemaking principles.

London Property Management Association (LPMA) noted that the proposed definition of Union and Enbridge was insufficient and could lead to unfair treatment of potential customers. LPMA suggested further clarity by adding that the communities should be separate and identifiable from other communities.
The NOACC coalition suggested a broad definition of community and suggested an explicit reference to rural and remote communities to ensure that their interests are specifically considered.

Anwaatin Inc. (Anwaatin) submitted that the OEB should include First Nations in its definition of community regardless of whether the First Nation in question meets the OEB's criteria for being considered a community.

Issue 2

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

In response to issue #2, the OEB received submissions from many parties on the OEB's jurisdiction to create an expansion fund whereby the customers of one utility would subsidize the expansion activities of another utility. The parties were more or less evenly split on this issue. Those arguing that the OEB did not have jurisdiction cited the lack of specific statutory authority and the "implied exclusion" maxim. Those arguing that the OEB does have jurisdiction pointed to the broad powers included within the power to set just and reasonable rates.

The principle of "implied exclusion" relies on the argument that whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred to that thing expressly. Implied exclusion is relevant to the issue before the OEB because the OEB already administers two programs that are broadly similar to a cross-utility expansion fund: rural and remote rate assistance and the Ontario Electricity Support Program. However, these are programs which the OEB is specifically mandated by legislation to facilitate – in particular through sections 79 and 79.2 of the Act. As these programs are identified by statute, there is clearly no jurisdictional impediment and these are not useful precedents in support of an expansion fund that is not mentioned in any legislation.

However, the fact that the legislature enacted specific legislation to grant the OEB the power to administer two programs that are similar to an expansion fund, and yet has not enacted legislation that expressly permits an expansion fund, suggests that the OEB may not have the general power to enact such a program through its ordinary just and reasonable rates powers.

Union and Enbridge relied on the above opinion to argue that had the government desired to permit cross-utility subsidization within the gas sector, it would have done so through legislation.

Union further argued that cross-utility subsidization would not be in accordance with the just and reasonable standard. If Union were to charge its customers amounts that would be used as a subsidy for other distributors that portion of Union's rates would not reflect the costs to serve its customers. Rather, that portion of Union's rates would be based on the costs incurred by another utility to serve its customers. Union further argued that such an approach would be contrary to the established ratemaking principle of "benefits follow costs". Union's customers would be incurring costs without receiving any corresponding benefits.

Enbridge cited a decision[3] of the Divisional Court that specifically noted that a cost of service approach is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly in rate setting. Enbridge submitted that the OEB had no jurisdiction under the governing legislation to make decisions about how funds recovered in rates from customers of a utility are to be allocated to other utilities and for the benefit of particular communities not currently served by a distributor.

Building Owners and Managers Association (BOMA) and Parkland cited similar arguments as Union in concluding that the OEB did not have jurisdiction to approve a framework permitting cross-utility subsidization. Parkland argued that it was not the function of the OEB to balance the interests of one company with the conflicting interest of another company's customers.

[3] Advocacy Centre for Tenants Ontario et al v. Ontario Energy Board, 2008, CanLII 23487

The Canadian Propane Association (CPA) argued that the OEB did not have jurisdiction to impose cross-utility subsidy as it would amount to a redistribution of wealth. The subsidy imposed by OEB was a tax according to CPA.

Those supporting the argument that the OEB did have jurisdiction to impose a cross-utility subsidy cited the broad powers of the OEB to set rates and the latitude of the OEB to set rates and other charges as confirmed by court decisions. EPCOR, SEC, Vulnerable Energy Consumers Coalition (VECC), South Bruce and OEB Staff cited the ACTO case[4] where the Ontario Divisional Court concluded that "just and reasonable rates" were those that responded to the OEB's statutory and policy objectives, even if that meant a departure from the traditional cost-of-service approach including the principle of cost-causation. The Court found that the OEB did have jurisdiction to implement a low income affordability program. The parties therefore argued that the same rational applied in the community expansion proceeding with respect to allowing cross-utility subsidization. Greenfield Specialty Alcohols Inc. (Greenfield) supported the above argument and referred to the Toronto Hydro Electric System Ltd. V OEB (2009) decision wherein the Divisional Court found that the OEB had broad authority to regulate the energy sector in Ontario and to balance competing interests.

OEB staff cited the Ontario Uniform Transmission Rate ("UTR") as an example of what is at least partially a cross-utility subsidy that is not mandated by statute. OEB staff noted that the OEB's powers with respect to electricity transmission rates are the same as its powers for electricity distribution and gas distribution and transmission. For transmission, however, the OEB has created a single blended volumetric network rate[5] that is effectively paid by all consumers.[6] There are five electricity transmitters in the Ontario electricity transmission rate pool, and the OEB sets all of their revenue requirements separately. These five revenue requirements are then added together to form a combined revenue requirement which in turn produces a single uniform

[4] Advocacy Centre for Tenants-Ontario v. Ontario Energy Board, [2008] O.J. No. 1970 (Div. Ct), para. 57
[5] There are actually three separate rates: the network rate, the line connection rate and the transformation connection rate. The network rate is paid by all electricity consumers and is effectively a single volumetric rate. About half of the combined transmission revenue requirement is recovered through the network rate. The line connection rate and the transformation connection rate are rates paid only by customers that impose additional costs on the system, through their use of a line connection or transformation services. See the Uniform Transmission Rate Decision and Rate Order EB-2015-0311, issued January 14, 2016 and corrected on January 15, 2016.
[6] Distributors pay a wholesale network transmission rate, which they recover from their customers as a retail transmission rate. The end result is that end use customers are paying the network transmission rate.

transmission rate that is ultimately charged on a volumetric basis to all electricity consumers. OEB staff submitted that this was a kind of cross-subsidy but noted that end use customers benefit at least in some measure from all of the transmitters regardless of which transmitter they are actually connected to.

EPCOR disagreed with the arguments presented by Union and Enbridge with respect to the just and reasonable standard and the principle of benefits follow costs. EPCOR submitted that consumers cannot be excused from paying for services based on the identity of the utility that provides them. EPCOR stated that the argument that utility ratepayers should only pay for those benefits provided by their chosen service provider was founded on an incorrect understanding of the “just and reasonable” rate-setting principle, and on the erroneous factual assumption that the only benefits received by a customer are those that are provided by the customer’s own service provider. EPCOR submitted that contrary to Union and Enbridge’s arguments, it was clear that the “just and reasonable” principle provided no jurisdictional barrier to the proposed expansion fund.

Issue 3

Based on a premise that the OEB has the legal authority described in Issue #2, what are the merits of this approach? How should these contributions be treated for ratemaking purposes?

Union and Enbridge submitted that there are no merits to an approach whereby customers of one utility subsidize the expansion costs of another utility.
Enbridge noted that inter-utility subsidization would require extensive efforts in attempting to accumulate volumes and cost data across all utilities to ensure that cost causality and cost allocation principles are applied consistently across all utilities. Enbridge further added that the introduction of such an approach would be costly to administer and these costs would have to be borne by all natural gas ratepayers.

LPMA submitted that should the OEB approve an approach whereby the customers of one utility fund the expansion efforts of another utility, then the framework should include all natural gas customers in Ontario including those that are not regulated by the OEB such as Kitchener Utilities, Utilities Kingston and Six Nations Natural Gas Company Limited.

LPMA further submitted that the cross-subsidization approach has no merits but several drawbacks. For example, not all utilities contributing to the subsidy fund may be able to draw on those funds as they may not have discrete communities large enough with no gas service. LPMA however recommended that if the OEB were to approve such a framework, then the cross-subsidization amounts should be treated as a contribution in aid to construction. South Bruce made a similar recommendation.

Northern Cross Energy Limited (Northern Cross) submitted that if a common fund is established for community expansion projects, then amounts should be allocated to the most economic projects first. South Bruce recommended that once a new customer becomes connected to the natural gas expansion system by way of a community expansion project, that customer should also be required to pay into the cross-subsidy to support future expansion projects.

Anwaatin submitted that the OEB should permit cross-utility subisidization through a universal service fund which is applied on a regulated utility basis and distributed on a fair and equitable basis to any qualified utility. Anwaatin further submitted that a primary objective of the fund would be ensuring that First Nation reserves and communities with substantial indigenous populations have access to natural gas service as quickly as possible.

Issue 4

Should the OEB consider exemptions or changes to the E.B.O. 188 guidelines for rural, remote and First Nation community expansion projects?

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

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

c) **What, if any, amendments to the E.B.O. 188 and E.B.O. 134 guidelines would be required as a result of the inclusion of any costs identified above?**

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

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

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

The OEB issued its *E.B.O 188 Final Report of the Board and the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* on January 30, 1998. In this Report, the OEB determined the criteria and the economic tests to be applied to distribution system expansion. One of the key determinations was to use a portfolio approach for a utility's distribution system expansion projects over a given year. The OEB set the minimum threshold for the Rolling Project Portfolio at 1.0 and the Profitability Index (PI) of an individual project to a minimum of 0.8. The OEB also determined the minimum threshold for the Investment Portfolio to 1.1 which included all distribution business projects necessary to attach customers of all rate classes in a given test year. The threshold of 1.1 was determined to minimize any forecast risk and undue rate impacts.

A PI of 1.0 implies that the projected revenues over a given number of years on a Net Present Value (NPV) basis are equal to the project costs. In other words, under the existing E.B.O. 188 framework, although an individual project may be subsidized to a certain extent, the portfolio of projects for a given year are not required to be subsidized by existing customers.

One of the primary issues in this proceeding is whether a change to the E.B.O 188 guidelines is required to support community expansion projects. In this context, the contentious issue is whether existing customers should subsidize a portion of the expansion costs into the new communities.

While CPA, BOMA, Ontario Geothermal Association (OGA), LPMA, Parkland, CCC, IGUA and Energy Probe were opposed to changes to the E.B.O 188 guidelines primarily changes to the minimum PI threshold, OEB Staff, Federation of Rental-housing Providers of Ontario (FRPO) and VECC were more flexible.

Those who were opposed to any changes to the E.B.O 188 guidelines noted that existing customers should not be required to fund uneconomic expansions into new communities where the costs of doing so considerably outweighs the benefits. Parties argued that the E.B.O 188 guidelines were established to ensure that existing customers are held harmless from the cost of new connections and this important objective should be maintained. Some parties (LPMA, CPA and VECC) noted that subsidising community expansion would distort the competitive market for other energy services (propane, geothermal etc.) in the communities as they would not be able to compete with subsidized natural gas service. IGUA submitted that uneconomic expansions are a matter of social policy, and the formulation and execution of social policy is the purview of the government and not the OEB.

LPMA, OEB staff, CCC and Parkland noted the substantial savings that customers in the new communities would realise from converting to natural gas. Those converting to natural gas from oil, wood, electric or propane would realise average annual savings of over $1,600[7]. With the inclusion of the expansion surcharge, the average annual savings are approximately $1,100[8] for both utilities' (Union and Enbridge) customers.

Parties also noted the results of a Stage 2 analysis that shows substantial savings over a 40 year period. The resulting Net Present Value of customers' net fuel savings from the Stage 2 assessment for all 39 projects of Enbridge is approximately $357 million. This means that the new community expansion customers of Enbridge will save approximately $357 million[9] over a 40 year period after accounting for the annual charges in rates and the cost to convert their equipment. Similarly, the new community

[7] Union pre-filed evidence in EB-2015-0179, Exhibit A, Tab 1, Table 1, Page 18
[8] Enbridge pre-filed evidence, EB-2016-0004, Table 1, Page 15
Union pre-filed evidence in EB-2015-0179, Exhibit A, Tab 1, Page 21
[9] Enbridge pre-filed evidence, Table 10, Page 33

customers of Union would save $313 million[10] over the 40 years with respect to the 29 community expansion projects. Consequently, parties posed the question as to why the new community expansion customers required any subsidy at all.

OEB staff noted that the benefits to new customers would be significant even with no subsidy at all from existing customers. For Enbridge, on a net present value basis the benefits to new customers are $357 million and the proposed subsidy is $123 million. Therefore, even with no subsidy at all, expansion customers would receive a benefit of approximately $234 million. For Union, the benefits to expansion customers without a subsidy are approximately $245 million ($313 million in benefits minus the $68 million subsidy).

However, OEB staff and FRPO recognized that some flexibility to the E.B.O 188 Guidelines is required to facilitate community expansion. Accordingly, OEB staff and FRPO suggested lowering the minimum PI threshold to 0.7 from 0.8 (after including the expansion surcharge and ITE contributions) while keeping the RPP to 1.0 and lowering the Investment Portfolio to also 1.0 from the earlier threshold of 1.1, essentially recommending no subsidization at the portfolio level.

Although VECC was opposed to any subsidies, it noted that should the OEB implement some level of subsidies, the subsidies should be implemented through a universal service fund that included contributions from all utilities.

LPMA too was opposed to any cross-subsidies but suggested minor changes to the existing E.B.O. 188 Guidelines. Similar to OEB staff, LPMA suggested a reduction to the Investment Portfolio to 1.0. LPMA further suggested that the RPP should not be for a rolling 12 month period but for a 3 year period initially and then extending to a rolling 5 year period. BOMA adopted LPMA's submission in this context.

A number of other parties suggested cross-subsidies apart from the utilities. Anwaatin, Greenfield, South Bruce, Northern Cross, NOACC, SEC and EPCOR all suggested subsidies as an important approach to expand access to natural gas. They all supported subsidies through a universal service fund that required contribution from all natural gas customers in the province. The utilities however opposed a universal service fund but supported subsidies from their existing customer base.

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[10] Union pre-filed evidence in EB-2015-0179, Exhibit A, Tab 1, Page 39

While SEC proposed a minimum PI of 0.6, none of the other parties that supported a universal service fund proposed a minimum threshold PI or RPP minimum PI.

Union in reply noted that although OEB staff and some intervenors supported community expansion, the support was muted and was based on the premise that there should be little or no subsidy from existing ratepayers. Union rejected this position and argued that if expansion was to have occurred on such a basis, then community expansion would have already happened and there would have been no need for the proceeding[11]. Union submitted that rational expansion of natural gas services should be considered within the intent of the Minister's letter to the OEB and the OEB's initiation of this policy proceeding rather than the strict and narrow construct proposed by SEC and LPMA.

Enbridge made similar arguments in its reply and noted that the Minister's letter asking the OEB to ensure the rational expansion of natural gas for all Ontarians cannot be accomplished without changes to the existing E.B.O 188 framework; otherwise the communities seeking natural gas would have already been connected[12]. Enbridge noted that the fact that the existing E.B.O 188 Guidelines allow an individual project PI of 0.8 shows that some level of subsidy already exists.

In its application, Enbridge identified a subset of 19 communities that it intends to serve using Liquefied Natural Gas (LNG). Enbridge proposed to recover the cost of LNG from all customers through the company's gas supply plan. Although Northeast Midstream supported Enbridge's approach, OEB staff and CPA in their submissions opposed it. OEB staff noted that requiring all customers to pay for the cost of LNG supply would not be fair to existing ratepayers as they are not causing the incremental costs. OEB staff argued that communities that are served using LNG should pay the costs to serve them. CPA in its submission argued that LNG trucks would be essentially competing with propane trucks to serve the same customers. If subsidies were provided to LNG, then the propane business could be severely impacted. CPA submitted that the fact that propane delivery trucks and distribution centres can profitably operate without a subsidy suggests that LNG delivery trucks should also be able to operate without a subsidy.

[11] Union Reply Submission, page 6, July 11, 2016
[12] Enbridge Reply Submission, page 8, July 11, 2016

Costs included in Economic Assessment

OEB staff submitted that any leave to construct application for community expansion projects should provide separate costs for the transmission and distribution segment of the project as well as any upstream reinforcement costs. OEB staff was of the opinion that the information would allow the OEB to better evaluate alternatives including LNG or compressed natural gas.

Greenfield suggested that the OEB should consider the capital and operating costs of service expansion and the resulting tolls and tariffs with all relevant demand assumptions in its economic assessment of extending natural gas service to communities.

LPMA supported the evidence of Union with respect to costs that should be included in the economic assessment such as upstream reinforcement costs, minimum design costs, rate base revenue and customer forecast time periods.

Northeast Midstream submitted that the OEB should require distributors to incorporate all the costs associated with providing the incremental service in their economic analysis, including the incremental capital invested; incremental expenses such as taxes, operating costs and incremental gas, storage and transportation costs, on a marginal cost basis.

One of the major issues raised at the hearing was Union's proposed inclusion of advancement charges. Union in its application proposed that costs for upstream distribution system reinforcement costs be included in the economic assessment for any new attachments or load additions. Union noted that it was directed in an OEB Decision[13] to file in future applications, an estimate of the costs of any reinforcement of existing lines that may be necessary as a result of the specific application, and an assessment of the impact of the costs of reinforcement on the economics of the project. Accordingly, Union used this approach in the project to serve Port Elgin, Southhampton and Wiarton in 1997[14].

In this application, Union proposed that advancement charges be restricted to situations where material new attachments would result in a need to accelerate future

[13] Wingham Expansion Project, E.B.L.O. 253, 1995
[14] E.B.L.O. 259

reinforcement to within three years following the year the attachment is put into service. The rationale for using a three year period was that the planning and execution cycle for a major reinforcement project can extend that long, and Union did not want to be in a position where a small customer would be unable to connect because the system capacity had been fully exhausted. In addition to the above condition, Union proposed that the need for upstream reinforcement advancement charges be restricted to economic assessments where the requirement of a new attachment or load addition is 200 m^3/hour or higher. LPMA and OEB staff supported Union's position. OEB staff however suggested that if reinforcement did not materialize within the three year window, the advancement charge should be refunded to the particular ratepayers. This view was also supported by Energy Probe. The rationale provided by OEB staff was that the Ontario Government's implementation of a cap and trade program and initiatives to reduce Greenhouse Gas (GHG) emissions could lead to reductions in natural gas flows requiring no reinforcement.

The issue of advancement charges was raised by EPCOR at the oral hearing. EPCOR South Bruce and Northern Cross opposed the requirement of an advancement charge proposed by Union. EPCOR has signed a franchise agreement with the municipalities of South Bruce to provide gas distribution services in Kincardine and surrounding areas. In order to serve the communities, EPCOR requires gas supply from Union's distribution system. EPCOR in its submissions noted that Union had asked EPCOR to pay $4.2 million as advancement charges for the volumes it requires.

EPCOR argued that the imposition of advancement charges was a barrier to entry and was not based on actual cost but rather a hypothetical cost that may not be realised. EPCOR submitted that the OEB should deny the payment of advancement charges and any system reinforcement costs should be borne by all ratepayers.
South Bruce in its submission noted that the OEB approved an advancement charge in E.B.L.O. 259 but did caution Union that the advancement was entirely dependent upon the utility's estimates of demand growth in each of the other communities served by the line[15]. South Bruce and Northern Cross argued that advancement charges are anti-competitive as new entrants would not have access to the reinforcement plans of an incumbent and would be at a competitive disadvantage when considering expansion design options. South Bruce submitted that advancement charges are essentially a

[15] South Bruce submission, para 54, page 13, June 20, 2016

subsidy from customers of the proposed community expansion to the benefits of other ratepayers since all customers benefit from the reinforcement.

Union in reply noted that its proposal with respect to advancement charges was fair and reasonable as it would be unfair to tie up all existing capacity for the benefit of the customer triggering the reinforcement to the exclusion of other customers that may want to connect and would be subject to expansion costs which are triggered as a result of the needs of another customer.

EPCOR in reply argued that the OEB did not have jurisdiction to approve the advance reinforcement charge. EPCOR quoted section 36 of the Ontario Energy Board Act that states that the OEB may make orders approving or fixing just and reasonable rates and in doing so may adopt any method or technique it considers appropriate. EPCOR however noted that the Divisional Court has noted that the cost of service approach is necessary to meet the fundamental core objective of balancing the interest of all consumers and the natural monopoly in rate setting[16].

EPCOR further noted that in the case of a new advance reinforcement charge, the costs are speculative and therefore the OEB does not have the jurisdiction to set this type of rate.

EPCOR submitted that Union and EPCOR compete for franchises and the prohibition against unjust discrimination in monopoly utility rates is a longstanding common law principle. EPCOR noted the Federal Court Decision in the case of Challenge Communications Ltd. v. Bell Canada that the unjust discrimination principle also prohibits a monopoly utility from discriminating against a competitor[17]. EPCOR submitted that the purpose and intent of the advance reinforcement charge in this case was not based on the economics but was designed solely to prevent EPCOR from serving the municipalities of South Bruce.

EPCOR summarised its submission by stating that the advancement charges were discriminatory and arbitrary, comprised a form of marginal cost pricing, impeded competition, were a barrier to entry and created perverse incentives in the sense that

[16] EPCOR Reply Submission, page 4, July 11, 2016
[17] EPCOR Reply Submission, page 4, July 11, 2016

the incumbent would be incentivised to skew plans and customer forecasts in order to discourage entry.

Criteria for projects/communities that would be eligible for exemptions and other public interest factors that should be included in the criteria

Union proposed that projects that meet the definition of a community expansion project should be eligible for exemptions from E.B.O. 188. LPMA disagreed and noted that no projects should be eligible for an exemption from E.B.O. 188.

LPMA further submitted that other public interest factors that should be included in the criteria is the energy cost savings for consumers. This is the Stage 2 benefit analysis that is required under the E.B.O 134 Guidelines. Other factors such as economic development should also be considered according to LPMA.

Enbridge made similar submissions and suggested that the OEB should give more weight to Stage 2 benefits in the context of community expansion projects. Enbridge noted some of the other economic benefits of expanding service including higher levels of disposable income as a result of increased savings from conversion to natural gas, benefits to businesses involved in sales and installation of related products/services and greater employment opportunities from the sale and installation of natural gas equipment.

Exemption to costs included in economic assessment and the mechanism to include these exemptions in assessing specific community expansion projects.

Union submitted that all incremental costs for the minimum design of a project should be included in the economic assessment for that project. Union further submitted that advancement charges for future upstream distribution system reinforcement should not be included in the economic assessment of a project in cases where reinforcement is not expected for a period of 3 or more years following the year in which an attachment project enters service.

Union further submitted that the incremental costs associated with a preferred design over a minimum design should not be included in the economic evaluation of a project. Lastly, Union submitted that upstream transmission and storage related costs should be excluded from the economic assessment of a distribution project.

LPMA agreed with the submission of Union on all the issues noted above.

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

Union submitted that in cases where a project is not economically feasible (project PI less than 1.0 before any contributions or surcharges), public interest factors should be considered in assessing whether to proceed with the particular project. Union further submitted that a further assessment of the impact of not proceeding with a project should not be required as such an assessment would be complex and would require a public policy view.

LPMA agreed with the views of Union and noted that the opportunity cost of not proceeding with a project should be identifiable on a disaggregated basis and should include energy cost savings to potential customers, incremental property taxes as a result of the project, employment growth, environmental benefits, economic benefits to the community and municipality and incremental government revenues.

Issue 5

Should the OEB allow natural gas distributors to establish surcharges from customers of new communities to improve the feasibility of potential community expansion projects? If so, what approaches are appropriate and over what period of time?

Expansion Surcharge

Union and Enbridge have proposed the introduction of a single volumetric-based expansion surcharge of \$0.23 per m^3. The rate translates to an annual amount of approximately \$500 for every expansion customer. Union has noted that the surcharge is a mechanism for the new community expansion customers to contribute a portion of their annual savings from converting to natural gas towards the economic feasibility of the expansion project.
Union proposed that the maximum duration of the expansion surcharge would vary depending on the project economics and would be based on the period required to reach the minimum PI (proposed PI of 0.4). The maximum time-period for any given

project will be 10 years. Enbridge on the other hand proposed the surcharge for a maximum period of 40 years or until the project achieves a PI of 1.0.

None of the parties opposed the establishment of a surcharge for new community expansion customers. OEB staff, VECC, SEC, South Bruce, EPCOR, LPMA and CCC proposed that the expansion surcharge should be extended for up to 40 years in the case of Union's proposal. OEB staff noted that customers of the new communities will realize significant cost savings even after incurring the expansion surcharges. Enbridge and Union have estimated the average annual savings after the surcharge at approximately $1,100[18]. OEB staff argued that there was no reason why a new customer would not be willing to incur the surcharge for an extended period, considering that they would realize net savings year after year.

Union in its reply noted that extending the term creates significant forecast risk and would serve as a disincentive to conversion further affecting the economics of expansion. Union submitted that a 40-year surcharge period would in essence amount to higher rates for some communities on a long term basis as compared to other neighbouring communities with natural gas service. However, OEB staff in its submission argued that customers in the new communities were aware that it costs more to serve them and if Enbridge considered a 40-year term as appropriate then it should not be a major concern for Union.

LPMA opposed the calculation of the rate ($0.23 per m^3) and questioned the use of the same rate by Union and Enbridge. LPMA provided a range of rates and suggested adopting a midpoint within the range depending on the economics of the expansion project.

SEC made a similar argument as LPMA recommending that the surcharge be tailored to match the cost/benefit of a specific project. However, SEC agreed that a unique expansion surcharge for each community could be cumbersome and the OEB could therefore determine 3 to 5 different rates that could be applied to the different community expansion projects based on the economics (the PI) and the benefit to the community (EBO Stage 2 benefits).

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[18] Enbridge pre-filed evidence, EB-2016-0004, Table 1, Page 15
Union pre-filed evidence in EB-2015-0179, Exhibit A, Tab 1, Page 21

CCC submitted that distributors should have the ability to adjust the surcharge to account for material changes in the economics of the project such as higher than expected conversion rates. CCC further noted that based on the benefits of converting to natural gas, there was room to increase the surcharge rate from $0.23m^3 to 0.46m^3 or higher.

Energy Probe submitted that the OEB should establish a distribution rate surcharge as compared to a commodity surcharge to ensure that customers that purchase their commodity through a third party are also liable to pay the surcharge.
South Bruce cautioned the OEB to establish a surcharge that does not threaten the economics of conversion or the overall economic viability of the expansion project.

Contribution from Municipalities

Union and Enbridge proposed a contribution from the municipalities known as the Incremental Tax Equivalent. The quantum of the ITE contribution would be based on the estimated value of incremental property taxes collected from the utilities and would be required for a ten year period. In the case of Union, the ITE contribution would match the term of the expansion surcharge. All parties supported additional contribution from municipalities.

OEB staff proposed that the ITE contribution be extended for a maximum of 20 years or match the term of the expansion surcharge, whichever is less. OEB staff noted that the municipalities would realise significant benefits as a result of natural gas expansion including lower heating costs for homes, businesses, schools, hospitals and municipalities and the ability to attract residents and businesses. These benefits were cited by the municipalities in their evidence. OEB staff further referred to the evidence of South Bruce that showed potential savings of $27 million per year for the communities if there was access to natural gas[19].

OEB staff was of the opinion that municipalities should make a higher contribution as they were going to be the beneficiaries of natural gas service in terms of higher tax revenues and the increased ability to attract new businesses and residential taxpayers. OEB staff further noted that the additional revenues from the utilities' infrastructure taxes were not being realized today and the municipalities would not be foregoing

[19] EB-2016-0004 Transcript, Volume 3, May 9, 2016, Page 146

amounts that are in their current budget. For these reasons, OEB staff proposed a maximum 20 year term for the ITE contribution. FRPO supported the suggestion of OEB staff in reply.

SEC in its submission referred to the same benefits as OEB staff and accordingly proposed the ITE contribution for 40 years or until the project meets the minimum PI. In addition, for communities that are governed by an upper and lower tier municipality, SEC suggested that the ITE should be allocated to both tiers. SEC further suggested that the municipalities should be required to rebate back to the utility all incremental property taxes and not just the pipeline property taxes as proposed by Union and Enbridge.

EPCOR in its submission suggested that the contribution from municipalities should be negotiated between the municipality and the distributor and should be included in the franchise agreement.

South Bruce in reply submitted that the OEB should not make the ITE contribution mandatory. South Bruce noted that the municipalities have a legislative authority to collect property and pipeline taxes and it is up to the municipalities to waive the taxes voluntarily. South Bruce questioned the legal basis under which the OEB could require municipalities to rebate taxes that they were authorized to collect.

Treatment of Surcharge and ITE Contribution Revenues

Union and Enbridge proposed that the expansion surcharge and ITE contributions should be treated as revenue as opposed to a capital contribution. Union and Enbridge through interrogatory responses[20] demonstrated that ratepayers receive greater benefits in terms of a lower revenue requirement when the expansion surcharge and ITE contributions are treated as revenue.

OEB staff supported the position of Union and Enbridge. However, LPMA, CCC, SEC, EPCOR and FRPO opposed the proposed approach of the utilities. The parties submitted that the amounts representing surcharge should be treated as contribution in aid of construction (CIAC) while the ITE contribution should be treated as revenues.

[20] EB-2015-0179, Response to LPMA IR#1 and Exhibit S3.EGDI.SEC.20

SEC was of the view that the ITE contribution should also be treated as CIAC as it too was being proposed in the absence of a required CIAC payment.

LPMA in its submission provided calculations to support its position using Union's Milverton Project as an example. LPMA noted that the sum of the total revenue requirement over the 40 years is $14.8 million under the revenue approach and $11.8 million under the CIAC approach. In other words, over 40 years, customers would pay $3 million more in rates for the Milverton Project under the Union proposal[21].

Union in reply rejected the calculations provided by LPMA and termed it as flawed. Union noted that the calculations of LPMA were incorrect because the data only used the expansion surcharge and ITE collection in the CIAC case and reflected a comparison to zero expansion surcharge/ITE collections in the "revenue" case. This resulted in the CIAC case having a lower revenue requirement. Union provided a recalculation that showed a difference of $236,000 in favour of CIAC over a 40-year period[22], which is less than a 5% difference.

OEB staff in reply noted that CIAC is normally a lump sum payment that is provided to a utility prior to the construction of the project. They are not payments over an extended period. OEB staff further noted that treating surcharges as CIAC would create an inequity between incumbent utilities and new entrants. OEB staff argued that the incumbent utilities have proposed surcharges mainly because they have to charge rates as per existing rate schedules. Conversely, a new entrant would use a cost of service model to calculate its rates and these rates would be derived from the entire capital cost of providing service in the new communities. In other words, the surcharge would be bundled in the new entrant's distribution rates. Affording different treatment to the incumbent utilities and new entrants would not be an appropriate ratemaking approach according to OEB staff.

Further, Enbridge proposed that its expansion surcharge be applicable to all expansion customers while Union limited it to general service customers. In its evidence, Union revealed that contract customers in the 29 communities were not willing to attach to the system if an expansion surcharge was imposed. Union therefore concluded that it could capture the additional costs by requiring a capital contribution, extending the term of the

[21] LPMA Submission, Page 12
[22] Union Reply Submission, page 14, July 11, 2016

contract or increasing the minimum annual volume[23] for contract customers. Although contract customers would not be included in the overall analysis, Union indicated that they would be required to achieve the same PI as the community.
OEB staff submitted that the utilities should be given the required flexibility to accommodate contract customers as long as new community expansion customers are not required to subsidize the cost to serve contract customers.

Issue 6

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

Few parties made submission on other rate recovery approaches. Union maintained that the OEB should avoid where possible, prescriptive ratemaking approaches and allow utilities to bring forward rate proposals that can be reviewed on their merits.

South Bruce submitted that as an alternative to the universal service fund, the OEB should also consider an approach similar to the Rural or Remote Electricity Rate Protection Benefit and Charge (RRRP rate) that is used to subsidize rural and remote electricity ratepayers in Ontario. South Bruce noted that it would be easy to implement a RRRP rate for gas and the mechanics have already been established by the OEB for electricity.

In addition, South Bruce suggested that incumbent utilities should be allowed to charge stand-alone rates that are different from their existing rate schedules for an expansion community. South Bruce submitted that it would not be fair to incumbent utilities if new entrants are allowed to charge rates based on their cost to serve the community. CCC made a similar submission noting that such an approach would level the playing field.

EPCOR recommended that the OEB should consider a framework which allows for lower distribution rates in the initial years of a community expansion project in order to increase the rate of conversion in the initial years and allow new customers to absorb the cost of conversion.

[23] EB-2015-0179, Response to LPMA IR#12 and Enbridge IR #6

Issue 7

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

Union and Enbridge are currently operating under an Incentive Regulation (IRM) framework until the end of 2018. Union and Enbridge have proposed a capital pass-through mechanism to recover capital costs related to community expansion projects. Union noted that the investments are not "business-as-usual" and therefore cannot be managed within Union's OEB approved capital budget under the 2014-2018 IRM framework. Union further noted that in the absence of approval to recover the revenue requirement related to the capital investments, it would be unable to commit the incremental capital required to facilitate expansion to the communities[24].

Enbridge in its evidence submitted that irrespective of the ratemaking framework adopted by the OEB to facilitate community expansion, it should allow for the recovery of the associated revenue requirement in rates prior to the end of the current incentive regulation plan.

Some ratepayer groups submitted that the OEB should not allow the revenue requirement associated with community expansion costs during the remainder of the IRM framework. LPMA and BOMA submitted that the scale of expenditure that is forecasted to occur and placed into service by the end of 2017 and 2018 will be relatively small and not likely to be material. LPMA, CCC and BOMA further argued that the expenditures do not qualify under the Y and Z-factor provisions agreed to in the IRM Settlement Agreement for Union. Moreover, BOMA disagreed with Union's position of categorising the entire portfolio of expansion projects as a single project in order to make the projects eligible for a Y-factor treatment.

LPMA submitted that Union was requesting a change to the IRM agreement by allowing a new cost to be included in rates. LPMA argued that it would not be appropriate for the OEB to make a change to the agreement without consent of all the parties to the agreement. However, LPMA submitted that it was not against the concept of including

[24] Union Evidence in EB-2015-0179, Exhibit A, Tab 1, Page 33

the revenue requirement in rates prior to the end of the IRM framework on the condition that such treatment would be negotiated along with other changes.

SEC presented similar arguments as LPMA and noted that the Enbridge IRM decision and the Union Settlement Agreement[25] were carefully crafted to balance the needs of the utility with that of ratepayers and therefore no more changes should be accepted by the OEB.

On the other hand, OEB staff, EPCOR, South Bruce and IGUA supported Union and Enbridge's request to recover the revenue requirement associated with community expansion in rates outside of the OEB-approved IRM framework.

EPCOR and South Bruce agreed with Union that the need for investment related to community expansion was unknown at the time that Union's IRM framework was negotiated and approved. EPCOR noted that utilities already face enough risk in expansion market and the additional risk of not being able to pass through capital costs during the IRM framework was not appropriate. South Bruce submitted that if capital costs related to community expansion projects were not allowed to be recovered during the IRM period, it would lead to a delay in implementation of the expansion projects.

IGUA supported the recovery of the revenue requirement during the IRM period noting that it was another good example of an appropriate tool to provide regulatory flexibility to facilitate rational natural gas system expansion. However, it noted that this approach was more complicated for Union as its IRM framework is the result of a settlement agreement as opposed to an OEB decision. IGUA however noted that approving Enbridge's proposal to recover the revenue requirement in rates prior to the end of the IRM term while denying Union's would effectively penalize Union for having reached a settlement rather than litigating its current IRM plan. For these reasons, IGUA was willing to endorse affording Union the same regulatory flexibility.

Union in reply argued that the current capital pass through mechanism exists within the IRM framework. Union further submitted that irrespective of the IRM framework, applicants are not pre-empted from seeking relief for costs that are outside of the ordinary course of business and not contemplated within the existing rate order[26].

[25] EB-2013-0202, July 31, 2013
[26] Union Reply Submission, Page 9, para 25, July 11, 2016

Issue 8

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?

The Municipal Franchise Agreement (MFA) is an agreement between a municipality and the gas distributor that outlines the terms and conditions of access to municipal infrastructure by the gas distributors. It is essentially an operating agreement that specifies the provisions for access to road allowance, excavations, restoration and compensation for any changes to municipal infrastructure as a result of any work undertaken by the gas distributor. The MFA must be submitted to the OEB for approval under section 9 of the *Municipal Franchises Act*. The OEB with the input of municipalities has developed a Model Franchise Agreement that provides a template to guide natural gas distributors and municipalities as to the terms and conditions the OEB generally finds reasonable under the *Municipal Franchises Act*.

Prior to commencing work to supply gas within a municipality, the gas distributor must apply to the OEB for a Certificate of Public Convenience and Necessity (Certificate). Depending on the infrastructure proposed to be built, the gas distributor requires a leave to construct approval from the OEB under section 90 of the Ontario Energy Board Act.

Although a gas distributor may have entered into a MFA with a municipality, the OEB has the authority to authorise multiple gas distributors to operate within a single municipal boundary. In other words, two gas distributors could potentially operate within the boundaries of the same municipality but would serve different customers.

Union and Enbridge submitted that the OEB should not review or change the existing form of the MFA or the corresponding approval process. Union in fact stated that the OEB should re-affirm its expectation that the current MFA should continue to be adopted on a consistent basis across the province.

Union argued that the current MFA does not impose any specific barriers to expansion. A municipality can have multiple franchise agreements with different gas distributors and the existence of a MFA does not create a barrier for other gas distributors to offer their services in a community that is not currently served. Although Union agreed that a Certificate provides exclusive rights to distribute gas to a specific geographic area, Union was of the view that the OEB can review and amend the geographic area covered by a specific Certificate through an application to do so. Therefore there was no need to undertake a review of the MFA or the Certificate.

However, Union proposed that prior to entering into a MFA, a distributor should be obligated to inform the municipality of the rates that will be charged and any conditions associated with those rates. Union submitted that such an approach would ensure transparency, especially in cases where there are multiple proponents. In cases where pre-existing approved rate schedules do not exist, Union suggested that the OEB should approve rates prior to approval of the franchise or delay the approval of the franchise until rates are approved by the OEB.

EPCOR in its submission agreed with Union and Enbridge that specific amendments were not required to the MFA. However, it was of the opinion that Ontario municipalities should be free to negotiate agreements that meet the needs of local conditions. South Bruce made a similar suggestion. While BOMA did not believe that any modifications were required, it did suggest that gas distributors should be licensed like electricity distributors in Ontario.

South Bruce in its submission urged the OEB to clarify that MFAs are non-exclusive. Enbridge expressed a similar view and dismissed EPCOR's argument that incumbent utilities had an inventory of franchise agreements that were not being used. Enbridge submitted that franchise agreements were not exclusive and there was nothing to prevent a municipality to enter into them with more than one gas distributor.

South Bruce further urged the OEB to introduce a sunset clause in the MFA similar to the Certificate in the event that a distributor fails to construct the approved expansion in the franchise area. South Bruce submitted that the OEB should terminate the MFA after one year unless there is an active and valid Certificate. South Bruce further noted that under the current MFA, municipalities are beholden to a distributor for the entire 20 years regardless of whether the utility constructs the expansion infrastructure within the municipality.

OEB staff, LPMA, BOMA and SEC made a similar suggestion of including a termination clause whereby a MFA and Certificate would automatically expire if construction has not commenced within certain years of receiving approval by the OEB. While OEB staff suggested a term of 3 years, LPMA suggested a term of 5 years. LPMA further suggested that the OEB should consider amending the Certificate to cover only geographic areas actually served by a distributor in order to prevent banking of MFAs and Certificates in order to encourage other distributors to provide service in the un-served areas.

Issue 9

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

Union in its evidence submitted that a process requiring a Request for Information (RFI) or Request for Proposal (RFP) from multiple parties interested in providing gas distribution services in a community would not be helpful if projects still need to meet the current E.B.O. 188 Guidelines. Union argued that the largest barrier to expansion is economic in nature and the challenge was to reduce capital costs or change the required economic feasibility criteria. Enbridge made a similar observation and suggested that no action was required to facilitate the introduction of new entrants to provide gas distribution services in communities that do not have access to natural gas.

Union and Enbridge submitted that the current process provides sufficient flexibility for new entrants to compete for providing gas distribution services. In cases where more than one party is interested in providing service to a municipality, Union submitted that both parties can bring forward a Franchise, Certificate or Leave to Construct applications to the OEB or intervene in another party's application and the OEB could make a determination on which application to review. However, Union noted that the OEB would need to know the proposed rates and resulting rate impacts to customers in order to make a determination. Union and Enbridge submitted that rate impacts are a key determinant to any expansion proposal. LPMA agreed with the submission of Union on this issue.

Enbridge argued that it would not be possible for a municipality to make an informed decision and intelligent selection of a gas distributor in the absence of rate related information. Union further added that encouraging a municipality to have an RFI or RFP process in the absence of requiring an understanding of the costs and rates could result in a non-binding outcome and potential unmet expectations.

Union further submitted that the OEB should also consider whether new entrants would be able to satisfy the public interest in a manner comparable to the existing utilities. Union argued that encouraging existing distributors to expand their systems as opposed to encouraging new entrants would result in a more efficient natural gas sector in Ontario considering that they already have the required supporting administrative infrastructure.

For new entrants interested in providing gas distribution services in Ontario, Union proposed that new entrants should be capable of meeting the minimum requirements of a distributor. These included:

Operational Capability – Distribution system that is reliable and compliant with regulation, existence of emergency response procedures and technical staff, system integrity program, Gas Supply Procurement etc.

Ability to meet core expectations of the OEB – meet OEB service quality metrics, compliance with Affiliate Relationship Code, ability to deliver demand side management programs and compliance with future government policy mandates (Cap and Trade)

Financial Stability – Capital requirements, credit worthiness, ability to meet certain financial metrics and a financial plan for the specific expansion

Union further submitted that if the OEB's expectations of new entrants were not the same as that of existing utilities, the ability of existing utilities to compete on a level playing field with new entrants would be seriously jeopardized.

Enbridge agreed with the minimum requirements proposed by Union.

EPCOR in its argument submitted that competition for franchises can help achieve the objective of promoting the public interest. Competition can result in lower costs to customers and provides incentives to potential distributors to find ways to reduce capital costs or provide innovative offerings to secure a deal. EPCOR further noted that one of the most important benefits of competition is that it promotes dynamic efficiency by motivating proponents to find efficient ways of providing a range of energy services.

EPCOR cited the OEB's Framework for Transmission Project Development Plans that set out its policy for new transmission investment in Ontario. In that policy, the OEB noted that competition in transmission services in Ontario would drive economic efficiency for the benefit of ratepayers[27]. EPCOR referred to the East West Transmission Tie Line project where the OEB received six applications for designation and selected the Upper Canada Transmission Inc. (a partnership between NextEra Energy Canada, Enbridge Inc. and Borealis Infrastructure Management)[28].

EPCOR noted the initiative undertaken by South Bruce municipalities to select a distributor for providing natural gas services within their communities. South Bruce initiated a RFI process to canvass the market for potential suppliers of natural gas distribution services in March 2015. The municipalities received six proposals from which EPCOR was selected as the preferred proponent and a franchise agreement was signed with EPCOR on February 22, 2016.

South Bruce submitted that the OEB should encourage but not require municipalities to hold competitive procurement processes (RFPs, RFQs and RFIs) prior to entering into a franchise agreement. South Bruce noted that some municipalities may not want to hold a competitive procurement process and may prefer to sole source a franchise agreement. South Bruce disagreed with the submissions of some parties that proposed that the OEB should conduct the competitive procurement process or impose mandatory requirements on competitive procurement.

SEC presented similar arguments as South Bruce but submitted that for large communities, a competitive process must be required with specific bid criteria and information requirements.

In case of municipalities that hold a competitive procurement process, South Bruce submitted that confidentiality of the bids must be maintained. South Bruce further noted that municipalities are best positioned to represent the interests of local customers and must play an important role in selecting a natural gas service distributor in their communities.

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[27] EB-2010-0059 OEB Policy: Framework for Transmission Development Plans, August 26, 2010
[28] East West Tile Line Designation, Phase 2 Decision and Order, August 7, 2013

South Bruce and SEC outlined similar set of criteria as Union that focused on technical qualifications, financial capability and experience of proponents. South Bruce agreed that the needs of large users must be considered in any proposal but noted that municipalities are in the best position to consider the needs of the community as a whole. South Bruce noted the possibility that large users could prefer a rate design model that allocates a majority of the costs to other customer classes.

OEB staff in its submission agreed with Dr. Yachew representing EPCOR that the duties and responsibilities to select a party to enter into a municipal franchise agreement should reside with the municipality. However, OEB staff submitted that the OEB could facilitate this process by pre-qualifying a pool of potential proponents that would have the requisite financial and technical experience and expertise to operate a natural gas distribution system. OEB staff submitted that the decision criteria for the pre-qualification process should be similar to the criteria used in the East-West tie transmission line proceeding and those proposed by Union in this proceeding. Parkland also cited the East-West tie proceeding as the preferred approach to conduct a competitive process.

SEC noted that the OEB may not have the authority to mandate that franchise agreements have to be awarded by way of a competitive procurement process or to impose binding requirements of what must be included in franchise agreements. SEC noted that the OEB could only provide guidance to the municipalities.

Greenfield supported a competitive process for awarding municipal franchise agreements but submitted that any such process must include consultation with major customers prior to the granting of a MFA in order to ensure that the proposed options are efficient and effective.

Greenfield further submitted that the South Bruce municipal franchise applications that are currently before the OEB should not proceed until a framework has been determined in this proceeding and the South Bruce applications are in compliance with the established framework.

Issue 10

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

On February 24, 2016, the Ontario Government introduced new legislation on climate change. The proposed *Climate Change Mitigation and Low Carbon Economy Act* seeks to fight climate change, working with industry and other partners on the design of a cap and trade program. The cap will put a limit on the amount of greenhouse gases (GHG) that businesses, institutions and households can emit and will put a price on carbon including natural gas. The objective of the cap and trade program is to cut GHG emissions in the Province and encourage the development of clean technologies. The Government further introduced the Five Year Climate Change Action Plan in June 2016 that provides a roadmap for reducing GHG emissions and measures to invest the proceeds from the cap and trade program to accelerate the development and use of clean technology by businesses and homeowners.

Enbridge argued that the cap and trade program is not a barrier to expanding natural gas to unserved communities and Enbridge's proposal was aligned with Government policy. Enbridge noted that expansion of natural gas in communities that do not currently have access will contribute to reducing GHG emissions and will assist in meeting the Province's GHG reduction targets. Enbridge submitted that the cap and trade program will increase the energy cost savings for customers in the new communities that switch to natural gas from propane and heating fuel. Conversely, those converting to natural gas from electricity will realize a small decline in savings. Enbridge however noted that savings from converting to natural gas will remain significant, falling marginally from $2,165 per year to $2,081 per year.

Enbridge agreed with the submission of OEB staff that if the OEB is satisfied that expansion of natural gas to unserved communities will reduce GHG emissions, there was no further need to examine alternatives that may provide further GHG emission reductions. Enbridge reiterated OEB staff's position that a net reduction in GHG emissions was a sufficient test in this proceeding to evaluate the impact of a proposed cap and trade program on any alternative framework established to support the expansion of natural gas.

OEB staff in its submission stressed the fact that natural gas had the lowest combustion carbon footprint in the hydrocarbon family and with the exception of electricity; conversion from all other commonly used fuel sources would lead to a reduction in GHG emissions. OEB staff further noted that a price on carbon emissions would not have a material impact on conversion rates from electricity as the savings would decline marginally.

LPMA questioned the need of expanding the use of natural gas into communities that do not have access with long-lived assets when the government is promoting the rapid transition away from fossil fuels. LPMA argued that the climate change initiatives of the government could lower the demand for natural gas in unserved areas especially as the Province considers programs to promote clean energy technologies such as geothermal heat pumps, air-source heat pumps and solar energy generation systems.

CCC and IGUA submitted that the only impact of the proposed cap and trade program to the framework that the OEB may establish is on the economics of a proposed project and it is up to the customers in the new communities whether they want natural gas service.

The environmental groups (OSEA, Environmental Defence and OGA) submitted that in light of the Province's goal to reduce carbon emissions, the utilities must be required to assess sustainable energy technologies for all community expansion projects. OSEA submitted that if natural gas expansion is not more economical than sustainable energy solutions, the natural gas expansion project should not be permitted to proceed.

The environmental groups submitted that in many communities that do not have access to natural gas, homeowners and businesses are not seeking natural gas service but are seeking lower energy costs. In communities that do not have natural gas service, the costs to convert to sustainable energy technologies such as geothermal may be less than converting to natural gas and the operating costs of such technologies is also lower than natural gas. The environmental groups therefore argued that it makes more sense in the new communities to promote and install sustainable energy solutions.

OGA submitted that in light of the Province's mandate to aggressively reduce GHG emissions by 2050, the OEB should impose a moratorium on community expansion applications until the utilities present for the OEB's review, their strategy to achieve the goals of the Climate Change Action Plan.

OEB staff in reply disagreed with the recommendations of OGA and argued that the government was still committed to promoting natural gas expansion and details emerging from the Climate Change Action Plan confirm that homeowners and businesses will have continued access to natural gas.

Issue 11

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

Union, Enbridge, EPCOR and OEB staff submitted that since natural gas has lower GHG emissions than heating oil and propane, the proposed cap and trade program will increase the cost advantage for natural gas. In addition, those converting to natural gas from electricity will realize a small decline in savings. Enbridge noted that converting from electricity will still remain significant, falling marginally from $2,165 per year to $2,081 per year. Consequently, the utilities and OEB staff expect the cap and trade program to have a minimal impact on conversion rates.

South Bruce submitted that the cap and trade program is likely to result in increased savings from switching to natural gas (from higher carbon intensive fuels) and this may have a positive impact on conversion rates.

LPMA submitted that the cap and trade program will likely result in a decrease in conversions from wood and electricity due to lower savings and higher conversions from oil and propane. LPMA noted that a large majority of wood is self-provided in rural and northern areas and would therefore not attract the proposed carbon tax. LPMA recommended that the OEB should review estimated savings and conversion rates on a project by project basis due to the diversity of alternate energy sources across communities.

Issue 12

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

The Ontario Government through the Minister of Economic Development, Employment and Infrastructure has announced $200 million in Natural Gas Access Loans over two years to help communities partner with utilities to extend access to natural gas. The Government has also made available $30 million in Natural Gas Economic Development grants to accelerate projects with clear economic development potential[29]. The government has not provided any details or the criteria under which these grants and loans will be available. The OEB in Procedural Order No. 3 requested parties to provide comments in their submissions on how to incorporate the loan and grant programs into the economic feasibility analysis and how the disbursement of these funds might relate to the OEB's approval of expansions.

Enbridge and Union both submitted that under their proposed approaches, community expansion projects would be able to proceed without provincial funding. Almost all parties suggested than any government grant should be used as a contribution in aid of construction to reduce the capital cost of project. Parties also suggested that loans should be directed to new customers in the communities to defray the costs of converting their heating and water heating systems to natural gas. This would result in higher conversion rates since the upfront costs would be significantly reduced.

[29] February 18, 2015 Letter of the Ontario Energy Board

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2016-0004

Ontario Energy Board

Application under the Ontario Energy Board's own motion to consider potential alternative approaches to recover costs of expanding natural gas service to communities that are not currently served

PROCEDURAL ORDER NO. 3
May 30, 2016

On July 23, 2015, Union Gas Limited (Union) filed an application (EB-2015-0179) with the Ontario Energy Board (OEB) seeking approval to provide natural gas service to certain communities that are not being currently served. The application was in response to a letter[30] from the OEB inviting parties with the appropriate financial and technical expertise to propose one or more plans for natural gas expansion. The OEB further noted that it would consider requests for regulatory flexibility or appropriate exemptions in the context of an application made for approvals pertaining to expansion portfolios and specific projects.

Union in its application indicated that under its proposal, it could complete approximately 29 projects to provide natural gas service to 18,000 homes and businesses in 34 communities at an estimated cost of $135 million. Union also sought approval for rate recovery of four specific projects and leave to construct approval for three of the four projects.

In a letter dated January 20, 2016, the OEB informed all parties that it intended to proceed with a generic hearing on its own motion as the issues raised by all the parties

[30] OEB Letter dated February 18, 2015

in Union's application were common to all gas distributors and new entrants seeking to provide gas distribution services in communities that do not have access to natural gas. The OEB also noted in that letter that Union's application (EB-2015-0179) would be put on hold until the completion of the generic hearing.

Accordingly, the OEB issued a Notice of Hearing for the generic proceeding on February 5, 2016. In Procedural Order No. 2 issued on March 9, 2016, the OEB determined a final Issues List for the proceeding and set out the process for filing of evidence and discovery of that evidence. The OEB also scheduled an oral hearing in the procedural order.

The OEB held an oral hearing from May 5, 2016 until May 13, 2016. At the end of the hearing, the panel indicated that they would provide for two rounds of submissions and would provide further guidance on characterization of the submission that would best inform the panel.

On May 17, 2016, Environmental Defence filed a letter quoting a recent Globe and Mail newspaper article (May 16, 2016) that referred to the Ontario Government's upcoming Climate Change Action Plan. The plan reportedly aims to move consumers off natural gas and onto other sources of energy such as electric heat, geothermal and solar power. The plan also intends to adopt new building codes that would require all homes and small buildings constructed in 2030 and beyond to be heated without fossil fuels. Environmental Defence noted that the draft plan contains numerous provisions that would be highly relevant to this proceeding. Accordingly, Environmental Defence submitted that the first round of submissions for this proceeding should be scheduled one week following the release of the Climate Change Action Plan.

On May 19, 2016, the Canadian Propane Association (CPA) filed a letter supporting the proposal of Environmental Defence. However, CPA submitted that the OEB not only consider deferring closing arguments but also raised the possibility of whether there is any merit in allowing parties to file updates to their evidence to reflect changes in the Climate Change Action Plan, and/or whether a further round of interrogatories should be allowed so that parties may ask utilities and other intervenors to provide updated program data and forecasts reflective of any such new policy.

The OEB does not consider it necessary to delay the schedule for arguments in this hearing. The purpose of this hearing is to inform the OEB of what considerations should be included in a framework for examining the merits of specific gas distribution expansion proposals. It is the OEB's intent that the framework being developed will have the flexibility to adapt to the introduction of any programs or building code requirements that have a bearing on the prospective use of natural gas in any subject communities.

As the Ontario Government has not yet released the details or the actual Climate Change Action Plan, the OEB cannot speculate on its contents. Parties may choose to address in their submissions the impact of scenarios similar to that outlined in the media reports on the community expansion framework. In keeping with the OEB's stated intent regarding adaptability, submissions of this nature could inform the OEB in determining the degree of flexibility required in an assessment framework.

As mentioned above on the last day of the oral hearing the OEB stated that it would identify matters that it considered to be of particular significance in the establishment of a framework for assessing natural gas distribution system expansion proposals. The intent is to have parties address these matters in their submissions if they have adopted positions that are relevant to the identified matters.

The issues list used to scope this hearing and the OEB's ruling on the requests for additional information in its Decision on Incomplete Interrogatory Responses dated May 2, 2016, should be viewed as the primary guidance documents for scoping the arguments. The following questions flow from the evidence that was provided in the hearing and the OEB welcomes submissions on them.

In relation to issue # 8, the OEB would be further assisted if the parties could consider the following additional questions: Should the Municipal Franchise Agreement approval process be accompanied by a selection process? Who should conduct the process and what should the selection criteria be? How would the needs of large users be considered? Submissions on the current purpose and use of the Municipal Franchise Agreement would also be of assistance.

The panel would be also be assisted by comments regarding some jurisdictional issues. Parties will already be addressing the extent to which the OEB has the jurisdiction to authorize subsidies between utilities through issue #2. The OEB asks that parties further consider what, if any, changes to the OEB's jurisdiction would be helpful in allowing the OEB to foster the rational expansion of natural gas service in Ontario.

With respect to Issue #10, in addition to submissions on how to incorporate the loan and grant programs into the economic feasibility analysis, the OEB would welcome submissions on how the disbursement of these funds might relate to the OEB's approval of expansions. The OEB recognizes that ultimately the government will decide how this money is best used, but the OEB would like to hear the parties' views on the optimal use of these funds.

The OEB considers it necessary to make provision for the following matters related to this proceeding. The OEB may issue further procedural orders from time to time.

THE OEB ORDERS THAT:

1. Parties that wish to file written submissions must file their submissions with the OEB and deliver it to all other parties on or before **June 20, 2016**.

2. Parties that wish to respond to the submissions made by other parties must file their reply submissions with the OEB and deliver it to all other parties on or before **July 11, 2016.**

All filings to the OEB must quote the file number, EB-2016-0004 and be made electronically in searchable / unrestricted PDF format through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto, May 30, 2016
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario

Ontario Energy Board

GAS DISTRIBUTION ACCESS RULE

AMENDED MARCH 1, 2020
(ORIGINALLY ISSUED DECEMBER 11, 2002)

2. ACCESS TO GAS DISTRIBUTION SERVICES

2.1. Gas Distributor Provides Services

2.1.1 A gas distributor shall provide gas distribution services in a non-discriminatory manner.

2.1.2 A gas distributor shall respond to all requests for gas distribution services from a person in a timely manner. The gas distributor shall record, at a minimum, the receipt and response dates of each such request.

2.2 Connection to and Expansion of a Gas Distribution System

2.2.1 A gas distributor shall connect a building to its gas distribution system in accordance with subsection 42(2) of the Act.

2.2.2 A rate-regulated gas distributor shall assess and report on expansion to its gas distribution system in accordance with the guidelines contained in the E.B.O. 188 Report.

2.3. Gas Distributor Record Keeping Responsibilities

2.3.1 A gas distributor shall create or obtain, and maintain records relating to the following matters within its franchise area:

- system configuration;
- system operating limitations; and
- documents sufficient to demonstrate compliance with the requirements of this Rule.

2.3.2 The gas distributor shall file records described in subsection 2.3.1 of this Rule with the Board, if requested by the Board.

Enbridge Gas – Panel 10 – Customer Attachment Policies
Examination in Chief – Table 1

Customer Connections Capital Expenditure Supported by Different Revenue Horizons

Revenue Horizon	2024	2025	2026	2027	2028	Total	Reduction vs. 40 Year Revenue Horizon	CIAC per Customer
(Years)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	
40	304	248	258	254	250	1,314		
30	238	235	247	249	262	1,231	83	428
25	214	211	223	225	235	1,108	206	1,067
15	146	144	153	154	159	757	557	2,890
10	89	88	93	95	96	460	853	4,428

Note: 40 year revenue horizon reflects the Company's most updated capital forecast

Enbridge Gas - Panel 10
Customer Attachment Policies
Examination in Chief - Table 2

Impact on Customer Revenue Horizon based on Equipment Replacement Assumptions

Customers Renewing at Equipment End of Life	Years of Revenue		Blended Revenue Horizon
	Yrs. 1-20	Yrs. 21-40	
100%	20	20	40
75%	20	15	35
50%	20	10	30
25%	20	5	25
10%	20	2	22
0%	20	-	20

Note - Assumes 20-year equipment life