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Reply to the Attention of Laura Brazil
Direct Line 416.865.7814
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Our File No. 231915
Date March 21, 2016

RESS

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

Attention: Kristen Walli
Board Secretary
boardsec@ontarioenergyboard.ca

Dear Ms. Walli:

Re: CPA Evidence
EB-2016-0004

We are counsel to the Canadian Propane Association (the "**CPA**"), an intervenor in his proceeding.

We have reviewed the Draft Issues List and submit this evidence in accordance with the Decision and Procedural Order No. 2, issued by the Board on March 9, 2016.

CPA reserves its right to file supplemental evidence on any additional issues that may be added to the Issues List by the Board.

Yours truly,

Laura Brazil

/kk
Attach.
cc by email: Intervenors in EB-2016-0004 and EB-2015-0179

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

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EVIDENCE OF CANADIAN PROPANE ASSOCIATION

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This evidence is filed pursuant to Procedural Order No. 1 dated February 10, 2016, which invited intervenors in this hearing to submit evidence relating to the issues set out in the letter from the Ontario Energy Board (the "**Board**") dated February 5, 2016.

Canadian Propane Association ("**CPA**") is an intervenor in this proceeding. In the sections that follow, CPA submits evidence on four broad points against an order for natural gas subsidization. First, the Board has no mandate or jurisdiction to order natural gas subsidization.[1] Second, ordering natural gas subsidization would violate sound ratemaking principles. Third, natural gas expansion is already occurring in rural and remote Ontario communities without the need for subsidization. Finally, if the Board does allow natural gas subsidization, it should make utilities and their shareholders (not consumers) responsible for any cost overruns or revenue shortfalls arising from errors in the forecasts upon which the Board relied.

1. BOARD HAS NO MANDATE OR JURISDICTION TO ORDER NATURAL GAS SUBSIDIZATION

Natural gas subsidization is outside the Board's mandate. Subsidization can only be justified on non-financial grounds, such as the provision of general societal benefits or improving the provincial economy. However, the Board is an economic regulator[2] and promoting general economic development or social benefits is not its role. This is the mandate of Federal, Provincial and local governments.

[1] "Natural gas subsidization" means the permanent subsidization of natural gas expansion projects (i.e. subsidies for uneconomic expansion projects) by existing consumers either by payments to a consumer's own utility company or to another utility company.

[2] "Regulation of electricity and gas utilities is a form of “economic regulation". Laws, regulations and other requirements have been designed to address the natural monopoly position of these energy companies, acting as a substitute for the economic forces that would normally influence them in a competitive market. In that way, economic regulation of the activities of monopoly service providers protects the interests of consumers." Ontario Energy Board, “OEB Resource Guide: Energy Sector Regulation: A Brief Overview”, online: <http://www.ontarioenergyboard.ca/oeb/Industry/Media%20Room/Publications/OEB%20Resource%20Guide >; Exhibit 1, Tab 1, p. 2.

In the EBO-188[3] proceedings, Board staff warned that promoting general societal benefits and general economic development is beyond the Board's mandate. Board staff pointed out that it would "not be effective, efficient or fair to 'tax' existing ratepayers for general societal benefits" and that "economic development and the enforcement of social policy objectives is not the purpose of utility regulation."[4] Those principles remain true today.

It is also not the Board's mandate to choose winners and losers. It should not favour new customers (winners in the event of a subsidy) over existing customers (losers in the event of a subsidy). It should not favour gas suppliers (winners in the event of a subsidy) over other fuel suppliers, such as propane suppliers (losers in the event of a subsidy). To the extent that the Board can facilitate competition in Ontario energy markets, it should do so. It should not create an uneven playing field which advantages some market participants over others.[5]

Similarly, the Board must not prefer the special interests of a select group over those of the public. Proposals to the Board must "be considered in light of the general public interest and not local or parochial interest."[6] The Board has previously refused to give special treatment in the context of First Nations' request for special rates.[7] To prefer the interests of a select group of remote and rural consumers violates the Board's duty to consider the public interest as a whole.

In any event, the Board has no jurisdiction to impose a natural gas subsidy because it is a tax. A tax is "a levy to raise revenue for general purposes, while a fee is a levy to charge for services directly rendered."[8] Charging existing consumers for the purpose of subsidizing gas

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[3] *Interim Report of the Board: Natural Gas System Expansions for The Consumers' Gas Company Ltd, Union Gas Limited and Centra Gas Ontario Inc* (15 August 1996), EBO-188, Ontario Energy Board; Exhibit 2.

[4] *Interim Report of the Board: Natural Gas System Expansions for The Consumers' Gas Company Ltd, Union Gas Limited and Centra Gas Ontario Inc* (15 August 1996), EBO-188, Ontario Energy Board, at s. 3.4.1; Exhibit 2, Tab 2, p. 12, at para. 3.4.1.

[5] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, p. 5.

[6] *Union Gas Ltd v Dawn (Township)* (1977), 76 DLR (3d) 613 at 622 (Ont HCJ).

[7] *Decision with Reasons: Application by Ontario Hydro Networks Company Inc for Order Approving Year 2000 Transmission Cost Allocation and Rate Design* (26 May 2000), RP-1999-0044, online: Ontario Energy Board <http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Decisions/2000%20Decisions> at s. 3.6.13.

[8] *Canadian Assn of Broadcasters v R*, 2005 FC 1217 at para. 8.

expansion to new rural or remote customers is not a charge for services rendered. It is a tax to raise revenue for a general purpose.

The *Constitution Act 1867* provides that the authority to impose a tax must originate in the legislature.[9] Any delegation by the elected legislature of its power of taxation must be explicitly clear and unambiguous.[10] The Legislature grants the Board its jurisdiction and powers through the *Ontario Energy Board Act, 1998* ("OEB Act"),[11] the *Electricity Act, 1998*,[12] the *Municipal Franchises Act*,[13] the *Oil, Gas and Salt Resources Act*,[14] and the *Public Utilities Act*[15]. Nothing in the OEB Act or any other statute grants the Board jurisdiction to tax for natural gas expansion.

The Legislature has never given the Board jurisdiction to subsidize natural gas expansion. When the Legislature chose to grant the Board jurisdiction to subsidize electricity expansion, it amended the OEB Act to add section 79. Section 79 expressly grants the Board the authority to require existing customers to subsidize rural or remote electricity customers: "All consumers are required to contribute towards the amount of any compensation required under subsection (3) in accordance with the regulations."[16] However, the Legislature has chosen not to make any such amendment to the OEB Act for natural gas subsidization.

The Board had no jurisdiction to subsidize electricity distribution to rural and remote customers before section 79 was added to the OEB Act. If the Board had jurisdiction to subsidize electricity distribution to rural and remote customers before section 79 was introduced, section

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[9] *The Constitution Act 1867*, 30 & 31 Vict., c. 3, s. 54.

[10] *Eurig Estate, Re*, [1998] 2 SCR 565, 1998 CarswellOnt 3950 at para. 41.

[11] SO 1998, c 15, Schedule B.

[12] SO 1998, c 15, Schedule A.

[13] RSO 1990, c M.55.

[14] RSO 1990, c P.12.

[15] RSO 1990, c P.52.

[16] *Ontario Energy Board Act, 1998*, SO 1998, c 15, Schedule B, s 79(4); O. Reg. 442/01, s. 5(6): "A distributor or retailer who bills a consumer for electricity shall aggregate the amount that the consumer is required to contribute to the compensation required by subsection 79 (3) of the Act with the wholesale market service rate described in the Electricity Distribution Rate Handbook issued by the Board, as it read on October 31, 2001."

79 would have been redundant. However, statutes are interpreted to ensure that each section has meaning (*i.e.* they contain no redundant sections).

The Board's authority to set rates and its duty to act in the public interest are materially the same for both electricity and natural gas (other than section 79). Since the Board had no authority to subsidize electricity distribution to rural and remote customers before section 79 was added, the Board cannot now have the jurisdiction to subsidize natural gas distribution to rural and remote customers in the absence of permissive legislation similar to section 79.

2. NATURAL GAS SUBSIDIZATION VIOLATES RATE-MAKING PRINCIPLES

While subsidizing the expansion of natural gas in any form has the likely outcome of expanding natural gas service beyond what otherwise might occur, such subsidization, especially cross-company subsidization, is inconsistent with long-held ratemaking principles, specifically: 1) benefits follow costs, and 2) there is no harm to ratepayers.[17]

In the event that existing customers contribute through their rates to the expansion of service to new customers, benefits (for new customers) do not follow costs (paid by existing customers) and, thus, existing ratepayers are harmed.[18]

In the event cross-utility subsidies are permitted, the benefits and costs are further separated and confounded in that the costs are paid by one utility's ratepayers for the benefit of some other utility's new customers.

Legislation, plans, policies and commitments from government encourage the rational expansion of natural gas service and infrastructure and do not prescribe or otherwise advocate

[17] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, p. 5.

[18] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, pp. 5-6.

rate subsidies.[19] Gas utilities themselves have recognized that the expansion of gas to rural areas should only occur where natural gas makes "economic sense".[20]

The guidelines and economic tests from EBO-188 ensure that the expansion of a gas distributor's system does not lead to undue rate increases for existing customers.[21] These are consistent with sound rate principles and have worked well for many years. The tests should continue to be used going forward to ensure natural gas expansion is based on sound economics and creates no harm. There is no need for exemptions or changes to EBO-188 that would result in uneconomic expansion and subsidies.[22]

In its 1987 decision in EBO-134, the Board suggested that it could consider broader costs and benefits of a gas expansion project other than the strict economic feasibility of the project.[23] However, in the decades since EBO-134 was decided, the Board modernized its test through EBO-188 and its predecessors so that economic feasibility is the sole consideration in approving expansion projects.

The Board should not depart from the principles set out in EBO-188. However, if it chooses to revert to considering broader costs and benefits as suggested in EBO-134, the Board must consider both the benefits and the costs of expanding natural gas service to areas that are already serviced by other fuel suppliers.

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[19] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, p. 8.

[20] Remarks by Guy Jarvis, President, Enbridge Gas Distribution, Ontario Energy Network Networking Luncheon, June 19, 2013 at Toronto, Ontario, online: <http://www.ontarioenergynetwork.org/resource-library.php>; Exhibit 5, Tab 5, at p. 5. Nicholas Zeeb, "Interview with Steve Baker" *Ivey Business Review Blogs* (March 31, 2015), online: Ivey Business Review Blog < http://iveybusinessreview.ca/blogs/nzeebhba2016/2015/03/31/steve-baker/>; Exhibit 6, Tab 6, p. 2.

[21] Ontario Energy Board, "Guidelines for Gas Expansion in Ontario", Expansion of Natural Gas Distribution (EB-2015-0156) Web Briefcase (November 11, 2015), online: <http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/Guidelines_for_Gas_Expansion_in_Ontario.pdf>; Exhibit 4, Tab 4, p. 8.

[22] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, pp. 6-7.

[23] EBO-134 Report, pp. 45 and 46, 6.74 and 6.75.

In any event, the Ontario Government's recently announced loan and grant program should be incorporated into any economic feasibility test the Board adopts.[24]

3. EXPANSION IS ALREADY OCCURING WITHOUT SUBSIDIZATION

Currently, energy markets are working efficiently, energy consumers have choices, and energy suppliers are delivering.[25] Moreover, new natural gas suppliers are entering rural and remote areas. This is illustrated by the Request for Information ("**RFI**") process recently completed by the rural and remote Municipalities of Kincardine, Arran-Elderslie and the Township of Huron-Kinloss. Seven entities responded to the RFI, including the ultimate winner, EPCOR Utilities Inc. EPCOR is a new entrant to the Ontario natural gas distribution market, however, its proposal for natural gas distribution does not require any subsidy from existing customers of other utilities.[26]

4. IF SUBSIDIZATION IS PERMITTED, UTILITIES SHOULD BE RESPONSIBLE FOR FORECAST ERRORS

If the Board permits uneconomic expansion, it is essential that utility shareholders bear any risks and costs associated with forecasting errors.

Utilities seeking leave to construct expansion projects must obtain approval based on, among other things, forecasted customer attachment rates. However, there have been significant forecasting errors in recent remote and rural natural gas expansion projects. These forecasting errors are detailed in a KPMG report dated March 31, 2015, which was filed with the Board as part of its Natural Gas Expansion Policy Consultation.[27] For example, in New Brunswick,

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[24] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016 at; Exhibit 3, Tab 3, p. 11.

[25] Expert Report of Charles Budd "Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Projects" dated March 4, 2016; Exhibit 3, Tab 3, p. 7.

[26] Various news articles and EPCOR website; Exhibit 7, Tab 7.

[27] KPMG, "Jurisdictional Review of Natural Gas Distribution Systems Expansions," March 31, 2015, online: < http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/report_KPMG_Natural_Gas_Expansions.pdf>; Exhibit 8, Tab 8.

Enbridge forecasted that a new expansion project would result in 70,000 attachments in 23 communities. Fifteen years later, it has only 12,000 customers in 10 communities.[28] Enbridge's attachment forecasts were off by 83%. Similarly, in Maine, SNG forecasted in 2013 that it would initially serve 15,000 customers.[29] As of 2015, it serves only 3,000.[30] Again, its attachment forecasts were inaccurate by 80%.

Union's application and evidence overstates the benefit to consumers of converting from propane to natural gas. This is described in detail in the Expert Report of Gerry Goobie dated March 3, 2016.[31] Moreover, as stated in the Affidavit of Andrea Labelle, Union's application and evidence underestimates the costs of converting from other fuel sources.[32] Given that cost savings are the key determinant to whether a consumer will choose to convert, Union's application erroneously forecasts that a larger number of consumers will attach than would be forecast if the correct figures were used. In fact, in today's price environment, there is likely insufficient savings for consumers to justify converting from propane to natural gas.[33]

Inaccurate forecasts for economic projects pose little danger to the public interest. In an economic expansion, the project has a neutral or net benefit to consumers over a certain term. So long as the project portfolio must meet 1.0, utilities are required to compensate for forecasting errors that result in a lower profitability index than expected for a particular project by ensuring that only higher profitability projects are pursued thereafter. In other words, the overall project

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[28] KPMG, "Jurisdictional Review of Natural Gas Distribution Systems Expansions," March 31, 2015, online: < http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/report_KPMG_Natural_Gas_Expansions.pdf>; Exhibit 8, Tab 8, p. 43, at s. 3.3.6.

[29] KPMG, "Jurisdictional Review of Natural Gas Distribution Systems Expansions," March 31, 2015, online: < http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/report_KPMG_Natural_Gas_Expansions.pdf>; Exhibit 8, Tab 8, p. 19, s. 3.3.4.

[30] KPMG, "Jurisdictional Review of Natural Gas Distribution Systems Expansions," March 31, 2015, online: < http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2015-0156/report_KPMG_Natural_Gas_Expansions.pdf>; Exhibit 8, Tab 8, p. 15, ats. 3.3.6.

[31] Expert Report of Gerry Goobie dated March 3, 2016; Exhibit 9.

[32] Affidavit of Andrea Labelle sworn March 3, 2016, Exhibit 10, Tab 10, at para. 2.

[33] Expert Report of Gerry Goobie dated March 3, 2016; Exhibit 9, Tab 9, p. 11.

portfolio would still have a net economic benefit to the public despite the utility's forecasting error.

However, in an uneconomic expansion, existing ratepayers are already permanently subsidizing the expansion. Any decline in project revenue will result in an increase to the permanent subsidy paid by existing consumers. Accordingly, it is essential that forecasts are as accurate as possible to ensure that the project is not unduly burdensome to consumers.

When forecasted attachment rates are lower than predicted, utilities can seek to top up their revenue from consumers. Utilities can apply to the Board for approval of rates that are sufficiently high to ensure that the utility receives its regulated rate of return, despite the fact that revenues are lower than anticipated due to the utility's own forecasting errors. In other words, there is no financial incentive for utilities to make accurate forecasts.

If the Board permits uneconomic expansion, it is essential to the protection of the public interest that utilities are incentivized to prepare accurate forecasts. Utilities carrying out uneconomic projects should not be entitled to top up their revenue through rate-setting applications. At the end of the day the utility and its shareholders should be accountable for any revenue shortfalls.

5. CONCLUSION

CPA submits that the Board should decline to permit natural gas subsidization.

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Ontario Energy Board

OEB Resource Guide

Energy Sector Regulation: A Brief Overview

The OEB receives its jurisdiction from provincial legislation and regulations. In carrying out our mandate, we balance a number of objectives, including protecting consumers' interests and ensuring the viability of Ontario's natural gas and electricity sectors. To achieve this balance, we must ensure that the rules and regulations are applied fairly and consistently.

How have the OEB's role and energy sector regulation evolved?

For most of the 20th century, the publicly owned (Crown corporation) Ontario Hydro was the major force in Ontario's electricity sector. Ontario Hydro dominated all aspects of the province's electricity sector, serving as the primary generator and transmitter of power. It also had authority to regulate and set the rates at both the wholesale and retail levels. The OEB was created in 1960 with a limited mandate to set rates for the sale, distribution and storage of natural gas.

In the late 1990s, the government decided to restructure the electricity sector. These regulatory reforms included the breakup of Ontario Hydro, the creation of a wholesale electricity market and giving the OEB responsibility for regulating part of the sector.

The natural gas industry has been evolving since the federal/provincial agreement in 1985 that deregulated the priced supply at its source.

Why is the energy sector regulated?

Most industries in Canada are subject to some form of regulation governing what they can and cannot do. The energy sector, however, is more closely regulated than many other industries because of the unique characteristics surrounding energy supply and delivery.

For example, unlike other industries in which there are numerous companies competing to sell their products and services, electricity and natural gas distribution and transmission are considered to be "natural monopolies.". This is due, in part to the inefficiency of having duplicate facilities. Natural monopolies include infrastructure industries, such as electricity and natural gas delivery, that are capital-intensive and vital services. Since there is a significant economic "barrier to entry" in initially constructing the infrastructure, there is little or no competition and a firm in a

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natural monopoly position could price its products and services significantly above costs.

The primary goal of energy sector regulation, therefore, is to ensure that the public good is served in a marketplace that is not competitive.

What is “economic regulation”?

Regulation of the energy sector is considered a form of “economic regulation". Laws, regulations and other requirements have been designed to address the natural monopoly position of companies, acting as a substitute for the economic forces that would normally influence them in a competitive market. Economic regulation is also designed to provide oversight of the markets to protect consumers. The OEB’s role as an economic regulator is to balance the interests of regulated entities and consumers.

- The public is well served if both the pricing and the standard of service being provided are fair and reasonable. In this regard, the OEB’s objectives include regulating prices to levels that are “just and reasonable” for consumers and setting standards of conduct and conditions of service for entities to follow in their operations.

- The regulated entities are well served if they are viable businesses, so that they can sustain these pricing and service levels in the longer term. Entities must have a reasonable opportunity to recoup costs and earn a fair return for the significant financial investment they make in the supply and delivery of energy to consumers.

Economic regulation plays additional roles in terms of ensuring appropriate treatment of all consumers. For example, in a competitive market, dissatisfied consumers can complain, switch to a competitor or do without. Since these options are not readily available to them for electricity or natural gas distribution, the OEB also serves as a forum for hearing and attempting to resolve consumer complaints.

What are the benefits of regulation to the regulated entities?

- Regulation helps foster market integrity and public confidence.

- It provides legitimacy in matters such as rate changes because the public can be confident that such increases have been fully vetted, justified and explained.

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E.B.O. 188

IN THE MATTER OF the *Ontario Energy Board Act*[12JF7-0:1], 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 expansions for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: Pamela Hardie
Presiding Member
G.A. Dominy
Member
Judy Simon
Member

INTERIM REPORT OF THE BOARD

August 15, 1996

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APPENDICES

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1. THE PROCEEDING

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1.1.1 In the Centra Gas Ontario Inc. ("Centra") rates case Decision with Reasons - Part I, E.B.R.O. 489/ E.B.R.L.G. 34-14, dated March 23, 1995, at paragraphs 3.2.15 and 3.2.16, the Board stated:

16

> ... at the present time, all the [local distribution companies] have differing [financial] feasibility tests, differing threshold levels of [financial] feasibility and monthly contribution policies ... The Board finds that the evidence in this proceeding is persuasive that there is an urgent need for a review of the E.B.O. 134 Report. The Board has also been persuaded by the evidence that the determination of such a major policy issue should be the subject of a generic proceeding.

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1.1.2 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") 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 (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188.

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

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1.1.4 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. The Issues List is found in Appendix A[229].

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1.1.5 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 with Mr. O.J. Cook, C.A. acting as Facilitator.

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1.1.6 The Board received the *Report of Mr. O.J. Cook, C.A. Including Reports of the Parties 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 ADR Report"). The Report stated:

22

> By the end of the first day there was "consensus agreement" that there were essentially two opposing principles or philosophies among the participants. In the opinion of the facilitator, the views of the parties on fundamental principles were

> clearly divergent and those views, which were strongly expressed in the ADR conference must be recognized and respected.

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1.1.7 The Facilitator organized the parties into two groups, Group "A" and Group "B", on the basis of which principle on system expansion they espoused. The ADR Report included a report from each of these groups and a report on those items on which the two groups were agreed.

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1.1.8 The Report of Group "A" stated:

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> The central feature of the Group "A" approach is that some subsidy of system expansion may be acceptable where necessary to obtain societal benefits, defined by the Societal Cost Test ... or a variant thereof.

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1.1.9 Group "A" included: Northern Ontario Municipal Association ("NOMA"); Federation of Northern Ontario Municipalities ("FONOM"); The Ontario Federation of Agriculture and The Ontario Pipeline Landowners' Association ("OFA/OPLA"); Ontario Native Alliance ("ONA"); Consumers Gas; Pollution Probe; The Green Energy Coalition ("GEC"); Centra; and Union.

27

1.1.10 The Report of Group "B" stated:

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> ...Group B suggest that in the ordinary course the public interest should only include:
>
> Security of Supply
>
> Safety
>
> Obligation to serve in areas where existing service is available...
>
> A **new business** project must pass the Financial Test.

29

1.1.11 Group "B" consisted of: Board Staff; The Consumers' Association of Canada ("CAC");The Canadian Industry Program for Energy Conservation ("CIPEC"); The City of Kitchener ("Kitchener") and The Industrial Gas Users Association ("IGUA"); Energy Probe; Municipal Electric Association ("MEA"); The Ontario Coalition Against Poverty ("OCAP"); and Power Workers' Union ("PWU").

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1.1.12 Having reviewed the ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order the Board recited:

31

> ... the Board has determined that it needs to deal first with the substantive philosophical differences between Groups "A" and "B". The Board would be best assisted, at this stage of the proceeding, by receiving argument on the issues shown below. Following the Board's determination on these issues, further procedural order(s) will be issued.

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1.1.13 The Board then ordered that the parties choosing to file argument and reply should focus their submissions on the following issues:

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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?

34

1.1.14 Arguments were filed on February 2, 1996 and reply arguments were filed on February 19, 1996.

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1.1.15 The intervenors in the E.B.O. 188 proceeding are shown in Appendix B[289]. The parties submitting argument and reply on the specific issues set out above are listed in Appendices C[294] and D[297] respectively. Parties writing letters of concern are listed in Appendix E[300].

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2. THE BACKGROUND

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2.1.1 In 1987, after denying a number of system expansion applications by Consumers Gas, the Board held a generic hearing under Board File No. E.B.O. 134 to review the criteria used by the utilities to assess and justify system expansion projects.

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2.1.2 In the June, 1987 E.B.O. 134 Report of the Board, the Board noted that in prior proceedings, when considering the public interest, "the Board has been satisfied if the welfare of the public is enhanced without imposing an undue burden on any individual, group or class" and stated that the Board would continue to be guided by this general principle when considering the extension of gas service. Further, in its E.B.O. 134 Report, the Board stated that financial feasibility was not to be the sole criterion examined in reviewing system expansions and that it was appropriate for existing customers to subsidize expansions that were in the overall public interest where the subsidy did not cause an undue burden on existing ratepayers.

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2.1.3 In the E.B.O. 134 Report, the Board directed the utilities to develop a three-stage process to aid the Board in its determination of whether or not a proposed system expansion is in the public interest. The first stage ("the Stage I test" or "Financial Feasibility test") was to be based on a discounted cash flow ("DCF") analysis; the second stage ("the Stage II test" or "Participant test") was to be designed to quantify all other quantifiable public interest factors not included in Stage I; and the third stage ("the Stage III test") was to take into account all other relevant public interest factors plus the results from the Stage I and II tests.

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2.1.4 Following the release of the E.B.O. 134 Report, the utilities each developed their own Stage I, II and III tests. The inputs varied somewhat from utility to utility.

42

2.1.5 On a case by case basis the utilities made applications for distribution system expansions that showed that the DCF analysis at Stage I resulted in a profitability index ("P.I.") or benefit to cost ratio of less than 1.0 and argued that the impact would not be an "undue burden" on existing customers. It should be noted that Union and Centra describe the results of their DCF analyses as a P.I. and Consumers Gas describes the result as a benefit to cost ratio. For the purposes of this Interim Report nothing turns on whether the results of the DCF analyses are described as a P.I. or a benefit to cost ratio and the Board uses the terms interchangeably.

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2.1.6 In the Board's June, 1990 E.B.L.O. 231 Decision ("the Deep River Decision"), the Board noted that several system expansion projects had been approved with benefit to cost ratios between 0.63 and 1.0. The Board stated that a proposed project that was forecast to recover less than 100 percent of its costs but more than 75 per cent would be considered marginal and could be justified on the basis of positive results from the Stage II test. The Board stated that any project that was forecast to recover revenues less than 75 percent of the cost of the project would not be considered marginal and would only be approved if there were very significant other public interest factors. If a project were forecast to recover less than half of the costs, even very significant other public interest factors would not justify the approval of the project.

44

2.1.7 In addition, in the Deep River Decision, the Board stated that the Board would consider not only whether or not the rate impact of a marginally uneconomic project would be undue but it would also consider what "... level of subsidy for the project under review is fair and reasonable for the existing ratepayers to assume ...".

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2.1.8 After the Deep River Decision, the Board required a minimum level of profitability for proposed projects. It was not sufficient to demonstrate that there would not be an undue rate impact on existing ratepayers as a result of the construction of an uneconomic project. Recently the Board has required a minimum P.I. of 0.8 for Union and Centra and accepted Consumers' proposal for a minimum benefit to cost ratio of 1.0.

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2.1.9 Also, recently, the Board has approved the use of contributions in aid of construction in the form of periodic contribution charges in order to increase the profitability of proposed distribution system expansions. Consumers Gas used the forecast revenues from these contributions in calculating whether or not a proposed expansion would achieve a benefit to cost ratio of 1.0. However, Union and Centra use the contributions to bring the P.I. of individual proposed projects up to the Board-approved minimum P.I. of 0.8 rather than seeking to achieve a P.I. of 1.0.

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2.1.10 In 1992, in an attempt to further standardize the analyses used to ascertain the feasibility of system expansion projects, Board Staff developed a proposal for a set of common filing requirements for system expansion applications. The proposal recommended that:

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- the Stage I test continue to quantify the benefits and costs that would accrue to the utility and existing ratepayers;

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- the Stage II test be reduced in scope to include only the quantifiable benefits and costs that would accrue directly to new customers; and

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- the remaining quantifiable public interest factors and all of the non-quantifiable public interest factors be included in the Stage III test.

50.1

These recommendations were adopted to the extent that they were deemed acceptable by each utility. However, there remained differences in each utility's tests.

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2.1.11 In its July, 1993 E.B.O. 169-III Report on the Demand-Side Management Aspects of Gas Integrated Resource Planning the Board recommended tests or screens to be used by the utilities to analyze the cost-effectiveness of demand-side management ("DSM") programs. These tests were designed to address many of the same concerns as the Stage I, II and III tests and included:

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the Societal Cost Test ("SCT") which consists of an evaluation of the costs and benefits of an activity to society as a whole;

the Rate Impact Measure ("RIM") Test which measures the impact of a DSM program on the utility's cost of service and rates; and

a requirement that any rate increase not impose an undue burden on customers, that programs be subject to qualitative assessments, and that program portfolios be identified and ranked.

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3. SUBMISSIONS OF THE PARTIES

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3.1.1 As noted, subsequent to the filing of the ADR Report, the Board in Procedural Order No. 4 ordered the parties choosing to file argument and reply to focus their submissions on certain issues. The Board summarizes below the main positions submitted by the parties under the following topics:

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- The Procedure

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- Obligation to Serve

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- Externalities

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- Which Tests Should Be Applied?

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- Subsidization and the Portfolio Approach

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3.1.2 Since in this part of the proceeding the Board has dealt only with the issues of principle raised in considering distribution system expansion, the Board has not summarized the evidence filed by parties on other topics. That evidence deals largely with technical issues and the "nuts and bolts" of evaluating the feasibility of system expansion projects. Under the heading The Next Phase the Board sets out its expectations for the next phase of this proceeding.

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3.2 THE PROCEDURE

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3.2.1 Board Staff noted in their reply argument that, except for Union and Centra, parties restricted their comments to distribution expansion issues. Board Staff recommended that storage and transmission issues raised by Union and Centra could be considered at a later date.

Was page 10 64

3.3 OBLIGATION TO SERVE

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3.3.1 Board Staff submitted that the obligation to serve is limited to section 54 (now section 55) of the *Public Utilities Act* and that the obligation extends only to areas of existing distribution. In Board Staff's view, the statutory obligation does not address the issue of equal access to service in areas of expansion or where service exists but is not available to all residents.

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3.3.2 Consumers Gas argued that section 55 imposes a legal obligation to serve only where there is a main currently in front of a customer's establishment and system capacity is sufficient to handle the added load. Even then these customers might be required to contribute to the cost of serving them.

3.3.3 Union and Centra stated that the customers' perception that the utilities have an obligation to serve should also form part of the Board's consideration in determining the public interest. 67

3.3.4 Pollution Probe submitted that the Board's primary mandate is to ensure that Ontario's energy service needs are met at the least societal cost. 68

3.3.5 OFA/OPLA submitted that by virtue of the utilities' status as regulated monopolies and the inability of new customers to seek service from an alternate supplier, utilities have an obligation over and above that of purely private, unregulated commercial entities. 69

3.3.6 CIPEC submitted that financial feasibility should be the only determinant for system expansion and that uneconomic expansion is not required as part of a utility's obligation to serve. 70

3.3.7 CAC submitted that a utility's obligation to serve does not require it to extend service when it is not economical, and that the Board has no jurisdiction to impose an obligation to serve that does not exist in law. 71

3.4 EXTERNALITIES 72

3.4.1 Board Staff argued that the Board has jurisdiction under the "public interest" provision of the OEB Act to require utility ratepayers to pay for environmental benefits that accrue to the general public. However, Board Staff argued that it would not be efficient, effective or fair to "tax" existing ratepayers to pay for general societal benefits. Board Staff further submitted that the inclusion of environmental externalities may lead to perverse outcomes that are neither economically nor environmentally efficient and that economic development and the enforcement of social policy is not the purpose of utility regulation. 73

Was page 11

3.4.2 Consumers Gas recommended that economic effects (employment creation, government tax benefits and foreign exchange externalities), special social factors and environmental (end-use emissions) externalities should all be considered in assessing system expansion. 74

3.4.3 Union and Centra submitted that social, environmental and economic externalities should be included in the SCT test as one determinant of the public interest. However, only those factors that can be easily quantified and for which some agreement exists should be monetized and incorporated into the test. 75

3.4.4 Pollution Probe submitted that the OEB Act, the efficient allocation of resources, generally accepted regulatory principles and government policy all entail that the Board must evaluate the environmental and economic externalities associated with natural gas system expansion projects. 76

3.4.5 GEC submitted that the inclusion of environmental externalities in supply-side tests is consistent with the Board's practice in regard to DSM and would provide symmetry between supply- and 77

demand-side investment rules. It further submitted that the issue of availability, uncertainty and acceptability of externality figures can be left for consideration in rate cases.

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3.4.6 IGUA stated that the Board has no power under the OEB Act or any other legislation to impose added charges on natural gas users because they will produce benefits for society at large. This, it argued, would be tantamount to the Board carrying out discriminatory taxation.

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3.4.7 Kitchener submitted that the Board has the jurisdiction to reject a project that has unacceptable environmental and social benefits, but not the jurisdiction to adopt "affirmative action" policies to create social or environmental benefits.

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3.4.8 CAC submitted that if environmental externalities are to become a part of the system evaluation process, the Board must first make a determination as to the appropriate values to be used.

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3.4.9 CIPEC submitted that in the absence of specific statutory authority, the Board does not have jurisdiction to use environmental externalities to justify system expansions. CIPEC further submitted that there are no specific statutory or regulatory provisions that give the Board jurisdiction to use environmental externalities to justify a system expansion.

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3.4.10 OCAP submitted that the average cost savings enjoyed by new customers is by far the largest external benefit and that this externality should be the only externality considered.

Was page 12 83

3.4.11 ONA argued that all socio-economic impacts should be considered, in fact, all relevant information should be considered. It submitted that if there are net societal benefits, "... subsidy up to the value of the quantifiable ... level of societal benefit, should be available to place a proposed expansion in a break-even position, subject to there being no undue rate burdens."

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3.5 WHICH TESTS SHOULD BE APPLIED

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3.5.1 Board Staff submitted that all new expansion projects should pass a financial test (net present value "NPV" equal to or greater than zero), that a market contribution should be sought from incremental customers when needed to bring the NPV to zero, and that the Stage II test would be useful to test the forecast amount of money that new customers might contribute to a project.

86

3.5.2 Kitchener and IGUA submitted that regulation should act as a surrogate for competition and that an unregulated utility is not able to deliberately make uneconomic investments without loss to the shareholders. They took the position that regulated utilities have an incentive to increase rate base so as to increase return.

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3.5.3 IGUA submitted that the Board ought to apply the same financial feasibility tests and guidelines that are used by unregulated industries and commercial interests operating in a competitive market and that financial feasibility ought to be the only determinant for system expansion.

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3.5.4 Kitchener submitted that adherence to the rule of economic feasibility would protect customers from rate increases caused by uneconomic investment. Kitchener also submitted that the Stage II test should continue to be used but only to confirm the revenue projections used in the Stage I analysis.

89

3.5.5 Energy Probe submitted that financial feasibility should be the only determinant for analyzing projects and that the public policy goals underlying the Board's E.B.O. 134 Decision have become anachronisms in a maturing gas system with widening fuel price differentials that make new services on the gas system financially attractive.

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3.5.6 Consumers Gas submitted that three tests should be used to illustrate the effect of expansion from different points of view: the SCT for society in general; the Financial Test for existing utility customers; and, the Participant Test for new customers.

91

3.5.7 Union and Centra argued that there was no evidence before the Board that would cause the Board to decide that system expansion criteria should be limited to financial feasibility. They argued that the Board should give primary weight to the results of financial feasibility tests but the public interest is best served when other factors are also considered.

Was page 13 92

3.5.8 PWU submitted that tests incorporating externalities should not be used as screening tests, but stated that should the Board consider that such a test is needed, the total resource costs ("TRC") test should be used rather than the SCT. PWU submitted that the major advantage of the TRC over the SCT is the elimination of administrative complexity, uncertainty and controversy that surrounds the use of environmental externalities. PWU also submitted that the Stage II participant test is fatally flawed as a screening tool because it measures only the benefits experienced by newly served customers without examining the associated costs to society as a whole.

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3.5.9 GEC submitted that financial feasibility should not be the only determinant for system expansion since the Board's role is not simply to enhance the situation of existing customers without regard to others.

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3.5.10 GEC also submitted that the SCT is the appropriate hurdle for all projects and that a DCF test is also necessary to allow the utilities to manage rate impacts and to seek contributions where necessary. GEC and Pollution Probe also supported the use of a "no net environmental loss" test for expansion projects.

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3.5.11 NOMA supported the use of the current three stage tests with some modifications, including the adoption of a wider area screening test rather than limiting the proposed service area to municipal boundaries.

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3.5.12 ONA argued in favour of an expanded societal cost test on the grounds that a holistic approach to system expansion should be used.

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3.5.13 MEA argued that only projects that pass a financial feasibility test should proceed. MEA also argued that the Stage II test should only be used to verify the forecast of customer contributions, if required, on the grounds that "An accurate and objective estimation ..." of the costs and benefits of fuel switching is difficult to perform.

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3.6 SUBSIDIZATION AND THE PORTFOLIO APPROACH

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3.6.1 Board Staff submitted that under the principle of cost causality, it is not proper for the existing subscribers to pay for the private benefit of a new group of subscribers. The introduction of a monthly market contribution has lowered the hurdle caused by large up-front contribution-in-aid of construction payments, providing a mechanism to minimize or eliminate the need for subsidies from existing ratepayers.

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3.6.2 Consumers Gas stated that existing customers receive a subsidy from projects with benefit to cost ratios greater than 1.0 and that the Board should only be concerned with the net effect of the expansion portfolio. For portfolios with a deficient NPV, the Board should determine the outer limit of financial subsidies based on societal benefits that would be tested periodically in rate cases.

Was page 14 101

3.6.3 Union and Centra argued that some subsidy within defined limits is reasonable and that "... permitting only incremental customers to subsidize existing customers is discriminatory".

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3.6.4 GEC recommended that maximum contributions be sought in all cases. This would result in substantially fewer subsidies than in the past. It further recommended that the Board should not predetermine an acceptable level of subsidy but should adopt an approach that is flexible while not cumbersome.

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3.6.5 NOMA recommended that the Board establish an amount of subsidy for system expansion for each utility on an annual basis.

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3.6.6 OFA/OPLA submitted that utility rates apply on a postage stamp basis based in part on the notion that distance should not be a factor in rate setting and that similarly more remote customers should not be penalized by reason of their location vis-à-vis sources of supply. OFA/OPLA also proposed the adoption of a rural rate class as a means by which otherwise non-sustaining extensions might be made economically viable with the sharing of net benefits between existing ratepayers and potential new customers.

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3.6.7 IGUA and Kitchener submitted that no level of financial subsidy ought to be applied to system expansions. CAC made similar submissions and stated that if the government believes that natural gas service should be extended to all communities that desire it, it should indicate so explicitly and should provide the funds from general revenues to support it. CAC also submitted that the setting of Stage I thresholds such as 0.8 as a measure of determining "undue rate impact" is arbitrary. Instead, the Board should consider in each rate case the cumulative rate impact of including projects that do not pass the Financial Feasibility test and decide on what level of subsidy is appropriate for that given year.

106

3.6.8 F&V Energby Co-operative Inc. ("F&V") submitted that expansion subsidies should not be permitted, indicating that preference for natural gas service is based on the misconception that natural gas will always be the fuel of choice and that now is not the time to add to stranded assets by permitting uneconomic expansions.

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3.6.9 Referring to letters of concern from interested parties, Board Staff indicated that the utilities and the Board should be mindful of the inequity and local sense of unfairness that may be produced if a community is served on a piecemeal basis. Board Staff recommended that in planning the size and timing of a project, decisions should be made in a way that would avoid isolating or "orphaning" certain parts of a community. They suggested that areas of contiguous service (i.e. water, sewer or cable lines) could be considered a community for planning purposes and that planning a project over a number of years might ensure that all potential customers are captured and pay the same amount for service. Board Staff stated it did not support regional expansion planning or the use of market areas as the form of business plan.

Was page 15 108

3.6.10 Board Staff submitted that all projects should proceed on a profitable basis and portfolios should not be used as a justification to construct unprofitable projects and the use of a rolling P.I. should be rejected. However, Board Staff submitted, as noted above, that the utilities should adopt a longer-term perspective and a community-based approach to project planning in order to address the perceived unfairness if a community is served piecemeal.

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3.6.11 CAC rejected the use of the portfolio approach because it can mask the role of subsidy, but encouraged the utilities to do longer range planning to cover likely development in a definable area.

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3.6.12 Consumers Gas submitted that the portfolio approach would reduce some of the frustration of communities and individuals who are denied gas service and would optimize societal benefits. Some projects showing a positive SCT result should be constructed as long as the overall portfolio maintains a benefit to cost ratio approved by the Board.

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3.6.13 Union and Centra also recommended a portfolio approach to system expansion where the total portfolio of distribution projects would be financially self-sustaining and impose no additional cost on existing customers.

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3.6.14 GEC endorsed a limited portfolio approach that requires the utilities to test each proposal, but in the case of smaller projects to provide limited information necessary to monitor cross-subsidy between "over-performers" and "under-performers". This would allow the utilities flexibility, avoid prolonged hearings, and allow the Board to control the overall impact on existing customers.

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3.6.15 IGUA submitted that the Board ought to require the utilities to account for expansion on a project-by-project basis with efficient use of resources as the objective. Kitchener adopted a similar position.

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3.6.16 PWU, which did not support the portfolio approach, submitted that it might be useful to the Board if the utilities were required to present the economic impact of the portfolio of all of their unprofitable projects as part of their filing to measure the rate impact in the aggregate.

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3.6.17 OCAP submitted that the sole purpose for using a portfolio approach is to define groups of projects within which cross-subsidization is permitted. If subsidies are permitted, project-by-project analysis is required to allow the Board to know the magnitude of subsidies being used for system expansion. OCAP objected to any portfolio approach that is intended to permit cross-subsidization and to hide the amount of cross-subsidization taking place, but submitted that grouping projects together would be acceptable provided it is being done to facilitate a more realistic assessment of project economics where costs are inter-dependent.

Was page 16 116

3.6.18 NOMA submitted that a portfolio should be defined as a collective application not arbitrarily limited by a municipal boundary but representing a wider community combined with a "pooling" of the subsidy budget. Similarly, OFA/OPLA recommended the adoption of a broader concept of "project" that incorporates all existing and new users within larger geographical boundaries and over a longer period of time.

Was page 17 117

4. THE BOARD'S DISCUSSION AND CONCLUSIONS

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4.1 THE PROCEDURE

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4.1.1 The Board observes that since most parties either implicitly or explicitly limited their arguments to the issue of distribution system expansion, the Board will make decisions only on this issue in this phase of the E.B.O. 188 proceeding.

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4.1.2 The Board notes that at this stage of the proceeding it is determining the principles that should underlie a policy on distribution system expansion. For this reason the Board decided to proceed on the basis of written submissions addressing the principles.

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4.1.3 4.1.3 Having made its determination on these principles in this Interim Report, the Board directs the utilities to develop the common guidelines and policies reflecting the Board's conclusions which are set out in this chapter. The Board expects the parties to this proceeding to reach consensus on the appropriate guidelines and policies, using those guidelines and policies as a basis for discussion. The guidelines, the policies and the position[s] of the parties will be placed before the Board for its review.

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4.1.4 The Board deals with the issue of which tests should be used when considering distribution system expansion under the headings Subsidization and the Portfolio Approach, and Externalities.

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4.2 THE BOARD'S JURISDICTION TO CONSIDER THE PUBLIC INTEREST

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Discussion

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4.2.1 The Board's jurisdiction to consider the public interest was not specifically enumerated in Procedural Order No. 4. However, the issue was raised in many parties' arguments particularly with respect to whether or not there should be subsidization of distribution system expansion by existing ratepayers; whether the Board should take into account factors other than financial feasibility when considering distribution system expansions; and, whether the public interest implies an obligation to serve.

Was page 18 126

4.2.2 The Board has the jurisdiction to consider the public interest in regard to distribution system expansion under two provincial statutes: the *Municipal Franchises Act*, R.S.O. 1990, c. M.55 ("the Municipal Franchises Act") and the OEB Act.

127 4.2.3 Before laying pipelines and supplying gas to the inhabitants of an area, a person must have received from the Board a certificate of public convenience and necessity under section 8 of the *Municipal Franchises Act*. In determining whether or not to issue a certificate, the Board must consider whether or not public convenience and necessity requires that a certificate be issued.

128 4.2.4 If a proposed distribution system expansion requires a transmission line, leave to construct under section 46 and 48 of the OEB Act must be obtained. Section 48 (8) provides that the Board may make an order granting leave to construct if the Board is of the opinion that the proposed line is in the public interest.

129 4.2.5 Under section 19 of the OEB Act the Board may approve just and reasonable rates for the "... distribution ... of gas." In setting just and reasonable rates the Board must determine a rate base for the distributor. In considering the cost of property to be included in rate base the Board may, under subsection 19 (5) of the Act, take the public benefit into account.

130 4.2.6 Thus, the Board may make public interest determinations with respect to a specific project through an application under section 8 of the *Municipal Franchises Act* and/or under subsection 48(8) of the OEB Act. Under section 19 of the OEB Act the Board considers the inclusion of the capital costs of these projects in rate base and the related owning and operating costs in determining a utility's cost of service.

131 4.2.7 For a given area, if a utility has a certificate of public convenience and necessity, the utility does not require specific Board approval for a distribution system expansion unless the expansion involves a transmission line or approval of a franchise agreement between the utility and the local municipality is required. Most in-fill projects within its existing franchise areas do not require specific Board approval. However, under section 19 of the OEB Act, the Board considers whether or not to include the costs of all expansions in rate base and cost of service.

132 ## Conclusions

133 4.2.8 In the E.B.O. 134 Report at para. 5.14 the Board stated:

> Was page 19 134
> The Board reiterates that the concept of public interest is dynamic and it must change according to the circumstances.

135 The Board is still of this view.

136 4.2.9 In this context the Board notes that the OEB Act was passed in 1960 after the TransCanada PipeLines Limited ("TCPL") pipeline was extended to Ontario making natural gas available to a much broader area of the province. The OEB Act was amended in 1964 and 1969 to include subsections 19(5) and 48(8) which require the Board to consider, respectively, the public benefit and the public interest.

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4.2.10 The Board's E.B.O. 134 Report was made after the Federal Government cancelled the Distribution System Expansion Program ("DSEP") and Canada Oil Substitution Program ("COSP"). Those programs were designed to reduce Canada's dependence on imported oil. DSEP provided funds to the gas utilities in Ontario in the form of contributions in aid of construction to assist in the expansion of the utilities' distribution systems. The key criteria for funding were the lack of financial viability and the volume of oil that the gas would displace. COSP provided a grant to homeowners for conversion from oil heating systems.

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4.2.11 The reference to "public convenience and necessity" in the *Municipal Franchises Act* was first passed in 1937. At that time, the TCPL pipeline had not been built and natural gas was available only to some residents of southwestern Ontario and manufactured gas only to residents of Toronto.

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4.2.12 The climate in which the natural gas industry operates has changed since the passage of the various Acts referred to. When making its determinations on the public interest and the principles raised in this proceeding the Board has considered the public interest in the context of the current circumstances of the natural gas industry.

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4.2.13 In determining the overall public interest, the Board has considered access to gas supply, operational efficiency, environmental protection and regulatory costs as well as economic feasibility.

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4.3 THE OBLIGATION TO SERVE

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Discussion

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4.3.1 At common law a public utility was compelled, "... to supply the [service or product] as a matter of duty..." (*St. Lawrence Rendering Co. v. The City of Cornwall*, [1951] O.R. 669 at 683). This common law principle has been codified in section 55 of the *Public Utilities Act*, which states:

Was page 20 144

> Where there is a sufficient supply of the public utility, the corporation shall supply all buildings within the municipality situate upon land lying along the line of any supply pipe, wire or rod, upon the request in writing of the owner, occupant or other person in charge of any such building.

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The issue that arose in this proceeding was whether section 55 obligated the utilities to provide service at any cost. It should be noted that unlike the OEB Act and the *Municipal Franchises Act*, section 55 does not refer to "the public interest", "public convenience and necessity" or "the public benefit".

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4.3.2 Section 55 must be read in conjunction with section 50(4) of the *Public Utilities Act*, which reads:

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> Any corporation before supplying any public utility to any person or to any building or premises, or as a condition of continuing to supply the utility, may require

> any consumer to give reasonable security for the payment of the proper charges therefor or for carrying the public utility into the building or premises.

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4.3.3 While the purpose of section 50(4) is to grant authority to public utilities to require security deposits, it is premised on the levying of "proper charges" for carrying the public utility into the building or premises. The question then arises as to the meaning of the term "proper charges".

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4.3.4 The common law also required that a public utility "... treat all customers alike, ... charge one no more than others ..." *St. Lawrence Rendering Company Ltd. v. The City of Cornwall supra at 683.* This requirement has been interpreted by the courts as an obligation "... to supply its product to all who seek it for a reasonable price and without unreasonable discrimination between those who are similarly situated or who fall into one class of consumers." *Chastain v. B.C. Hydro & Power Authority 32 D.L.R. (3d) 443 at 454 (B.C.S.C.).* This obligation has been codified in section 19 of the OEB Act, which provides for the fixing of just and reasonable rates for the sale, transmission and distribution of natural gas. While section 19 of the OEB Act does not directly address the issue of charges for providing the infrastructure necessary to distribute or transmit natural gas, it does provide that in fixing just and reasonable rates the Board must determine "... a reasonable allowance for the cost of the property that is used or useful in serving the public ...".

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Conclusion

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4.3.5 Upon reading section 19[12JF7-0:130] of the OEB Act together with the common law principles and the provisions of the *Public Utilities Act*, the Board has determined that a public utility does not have an obligation to serve without regard for the cost of providing the infrastructure that will permit it to provide the service. Further, the Board has concluded that distribution system expansion should not be undertaken absent a consideration of costs.

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4.4 SUBSIDIZATION AND THE PORTFOLIO APPROACH

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Discussion

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4.4.1 In any discussion of subsidization in a natural gas distribution system it must be recognized that there is inherently subsidization in any distribution system. For example, in order to set rates, costs are allocated to customer classes that are comprised of customers with similar characteristics. Each customer in the class pays rates that reflect the average cost to serve a customer in that class. These group rates result in customers with the lowest cost of service subsidizing customers that have higher service costs since all customers in the same class pay the same rate for the same natural gas service. In regard to new facilities, unless each customer pays the actual cost to provide that customer with gas service there will be subsidization among customers in any new service. In fact the Board has approved facilities applications where accidents of timing and geography or the inclusion in a project of financially viable customers has meant that service could be extended to some customers that otherwise would not be served by the project because service to these customers would not be financially viable on a stand alone basis.

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4.4.2 The question that arose in this proceeding, is, how should potential customers be grouped for the purpose of ascertaining the financial feasibility of new facilities? As set out, one extreme would be to calculate the cost of extending service to each and every proposed new customer. While this would eliminate subsidies toward the cost of new construction, none of the parties to this proceeding suggested this as an alternative although the Board understands that this approach has been used for individual in-fill attachments and dedicated lines to serve individual large volume customers. Calculating the cost of serving each new customer is not a viable alternative for distribution system expansions for the same reason that group rates have been accepted as the norm: the cost of such calculations would outweigh the benefit to be obtained from the calculations.

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4.4.3 For the purpose of calculating the cost of proposed new facilities, it has generally been the past practice of the utilities and this Board to group customers by project, each project being an undertaking that was to be constructed in one time frame in a geographically contiguous area. An exception to this practice has been the utilities' calculation of the cost of in-fill projects which has been done on a portfolio basis. Also, utilities keep track of the financial feasibility of their overall portfolio of all new distribution projects.

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4.4.4 Many parties to this proceeding argued that the Board should continue to assess the financial feasibility of new distribution facilities on a project by project basis. However, some of the parties argued that the Board should use an expanded definition of project which could cover more than one time frame and a larger geographic area. In this way, they submitted, the Board could continue to monitor the level of subsidization while at the same time permitting the extension of gas service to more customers than otherwise could be served using the current narrower approach to defining a project. It was submitted that if the Board did not monitor expansions at this level the degree of cross-subsidy would not be apparent.

Was page 22 158

4.4.5 The utilities have submitted that the Board should use a portfolio approach to analyzing the financial feasibility of distribution projects. All new distribution projects would be grouped together and would be required to be financially self-sustaining. Overall the projects would not impose a rate increase on existing customers. Although such an approach would serve to lessen the regulatory burden, the Board has concerns about this methodology too.

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4.4.6 If utilities are free to make their own determination of whether or not to include certain customers or communities in the portfolio it could lead to at least a perception of unfairness in that one community might believe that it was unfairly overlooked in favour of another.

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4.4.7 The Board is also concerned that in adopting the portfolio approach the utilities might make decisions that might put the ratepayers of the utility more at risk than the utility shareholders, such as overestimating customer attachments or attaching customers that may not continue to take gas service for the life of the pipeline.

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4.4.8 It has been the practice of this Board that when the Board has scrutinized the forecast financial feasibility of new distribution projects thoroughly, the Board has generally allowed the costs of the new projects into rate base unless it has been shown that some portion of the costs were imprudent.

If the utilities were to be given more latitude in making decisions on distribution expansions then the shareholders of the utility should be held more accountable for their decisions and forecasts.

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Conclusions

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4.4.9 It is one of the Board's goals in this proceeding to minimize regulatory costs by rationalizing the regulatory process for approving new distribution projects. Rationalization should ensure that the public interest is protected and allow the utilities to make decisions on expansions in a business like fashion within acceptable standards. In addition, the Board is aware that in some jurisdictions economic regulation has been evolving toward incentive and performance based regulation and a more "light handed" approach to regulation. The portfolio approach would be more consistent with these objectives.

Was page 23 164

4.4.10 The Board is concerned about the difficulty in defining the scope of a project. The Board observes that on occasion the utilities force-fit new services that may be sub-optimal in order to create a proposed project which meets the minimum level of P.I. or benefit to cost ratio. As a result of this force-fitting only some part of a community or a geographic area may be served with natural gas. For example, gas service may be extended half way down a street in an urban residential neighbourhood. It may even be that by proceeding in this manner the remainder of the area may never receive natural gas as it will always be financially unfeasible to serve the area. Force-fitting new services into proposed projects can also produce positive results. The presence of a financially viable large volume customer in a proposed project area could mean that financially unfeasible customers in the project area may be served whereas otherwise they would not be served.

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4.4.11 By limiting the utilities to grouping proposed new distribution system customers on a project by project basis for the purpose of determining financial feasibility, the utilities lose some of the flexibility to determine the optimal delivery network to service their existing and prospective customers. The ability to utilize the positive financial impact of serving financially feasible new customers to serve financially unfeasible customers is limited to the immediate geographic area and timing of the proposed project. The portfolio approach would provide the utilities with more flexibility in designing their delivery networks.

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4.4.12 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, more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.

167

4.4.13 When specific projects are presented to the Board a determination as to the reasonableness of the "project" definition must be made. The burden of ascertaining whether a project is a "project" would not be eliminated under the proposal to expand the definition of a project. In fact, the proposal to expand the definition of project would create, in effect, a mini-portfolio.

168

4.4.14 The Board notes that by assessing distribution system expansion on a project by project basis the problems relating to potential customers' sense of unfairness when they cannot obtain natural gas

service is not eliminated, nor is the problem that utilities may over-estimate the forecast attachments, nor will it protect ratepayers against the possibility that a large volume customer may not continue to take gas over the period of time on which the utility's feasibility analysis was conducted.

169

4.4.15 For all the above reasons, the Board finds that for each utility grouping all proposed new distribution customers for the test year into one portfolio for the purpose of ascertaining the financial feasibility of serving them is in the public interest.

Was page 24 170

4.4.16 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. The Board discusses these containment practices throughout the remainder of this chapter.

171

4.4.17 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.

172

4.4.18 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.

173

4.4.19 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.

174

4.4.20 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.

175

4.4.21 The Board recognizes that there will always be accidents of timing and/or geography in the determination of whether or not a particular project can proceed and that some communities may feel, as they sometimes do now, that they have been unfairly treated. The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. or benefit to cost ratio. Through the use of this methodology the utilities' distribution system project portfolios can be constantly updated to reflect the impact of profitable proposed new projects and unprofitable proposed projects can be reviewed by the utilities for possible inclusion 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:

> Was page 25 176
>
> rolling P.I. is a weighted average calculation of the cumulative NPV inflows divided by the cumulative NPV outflows during the preceding 12 months.

177

4.4.22 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.

178

4.4.23 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.

179

4.4.24 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.

180

4.4.25 In addition to calculating the Stage I financial feasibility of a project the utilities should define study areas for all proposed projects in order to ascertain the maximum number of customers that could be served at the most reasonable cost, environmentally, socially and financially. This should be done in order to optimize the route selection and project definition processes. This will also make each utility more accountable to inhabitants of their franchise areas for their decisions on which community or parts of a community the utility proposes to serve.

181

4.4.26 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.

182

4.4.27 The Board also expects the utilities to appropriately apply the *Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario, Fourth Edition, 1995*[12JF6-0:1] ("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.

 183

4.4.28 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.

184

4.4.29 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.

185

4.4.30 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.

186

4.4.31 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. A justification for such a project may be safety concerns.

187

4.5 LEVEL OF P.I. OR BENEFIT TO COST RATIO

188

Discussion

189

4.5.1 The Board must now determine the level of financial feasibility or Stage I P.I. that is appropriate for the overall portfolio of distribution system expansion projects.

190

4.5.2 The Board has identified four issues or points of view on what the appropriate level of P.I. should be. The first is that set out in E.B.O. 134 which is that it is acceptable for existing ratepayers to subsidize system expansions as long as the rate impact is not undue. The second point of view, which was espoused by many intervenors in this proceeding, is that each and every project should be financially feasible but certain phases or stages of the project, as defined, may not be financially feasible. The third point of view, which was generally espoused by the utilities, is that as long as a utility's overall portfolio of expansion projects reached a P.I. of 1.0 it is acceptable to proceed with some projects that are financially unfeasible. A fourth issue was whether or not existing ratepayers should have to forego lower rates by virtue of a utility undertaking projects that are not financially feasible

Was page 27 191

Conclusions

192

4.5.3 In considering the fourth issue or point of view, the Board observes that the expectation that existing customers should benefit from the addition of new customers in the form of lower rates is a regulatory argument, not a business or financial decision. The Board believes that this expectation was valid when a utility was first constructing infrastructure and would have incurred high initial costs which the first customers would have had to pay. As customers were added they would have received the benefit of the initial, more costly infrastructure without necessarily incurring all of the costs. Since the initial ratepayers did incur these costs it was reasonable to expect that they would benefit from the addition of new customers in the form of lower rates.

193

4.5.4 The Board observes that existing customers benefit from the addition of new customers in that these new customers will provide a future contribution to help share the cost of maintenance/betterment projects such as the replacement of pipes in older service areas.

194

4.5.5 At this stage the utilities are mature utilities with nearly fully developed distribution systems. Many of their existing customers have had the benefit of natural gas for some time.

195

4.5.6 The Board agrees with GEC's statement that "...the Board's role is not simply to enhance the situation of existing customers without regard to others." The Board is of the view that it is no longer reasonable that these customers should continue to expect to receive a benefit from the addition of new customers in the form of lower rates. Similarly, the Board also believes that it is not the role of the Board to enhance the situation of potential new customers without regard for existing customers. Therefore, the Board does not believe that existing customers should subsidize new customers through higher rates as a result of the construction of financially unfeasible new distribution system projects.

196

4.5.7 In addition, the Board notes that it has not been given a convincing rationale for selecting an appropriate level of subsidization that could be applied universally to all distribution system expansion projects.

197

4.5.8 With respect to the proposition that each and every project should be financially feasible, the Board has already noted the difficulty in defining a project and the fact that within many projects there are subsidies. The Board has already addressed the regulatory burden imposed by the necessity of testing whether a proposed distribution system project is a project and testing the financial feasibility of each proposed project. The Board expects that overall the portfolio approach will reduce regulatory costs and that the ratepayers and the public interest will continue to be protected.

Was page 28 198

4.5.9 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 or better 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.

199

4.5.10 However, at the present time the utilities calculate the DCF for proposed projects over long periods of time (generally 30 years for Union and Centra, and 55 years for Consumers Gas). 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.

200

4.5.11 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.

201

4.6 CONTRIBUTIONS IN AID OF CONSTRUCTION OR PERIODIC CONTRIBUTIONS

202

Discussion

203

4.6.1 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.

Was page 29 204

4.6.2 The Board notes that accidents of timing and geography mentioned above 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.

205

Conclusions

206

4.6.3 In order to determine whether or not a contribution is required, a project must be identified. The Board has already outlined the difficulties that arise when attempting to define projects for the purpose of calculating financial feasibility. Also, the Board is concerned that the calculation and levying of these charges may lead to a sense of unfairness within a community and increases the burden on the utilities, ratepayers and regulator.

207

4.6.4 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.

208

4.6.5 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.

209

4.7 EXTERNALITIES

210

Discussion

211

4.7.1 In its E.B.O. 169-III Report the Board defined Externalities as:

212

> A general term encompassing Social Externalities and Environmental Externalities.

213

4.7.2 The Board in its E.B.O. 169-III Report defined Social Externalities as:

Was page 30 214

> Costs and/or benefits, which affect the well-being or lifestyle of segments of the public as a direct result of a company's or individual's activities but which are not accounted for as a cost of doing business.

215

4.7.3 Environmental Externalities were defined as:

216

> Costs and benefits which result from changes to the environment as a direct or indirect result of a company's or individual's actions, but which are not accounted for as business costs or benefits.

217

4.7.4 Many intervenors argued against the use of externalities on the assumption that they would be used to justify otherwise uneconomic projects. Others argued that a positive societal cost test should be used to justify otherwise uneconomic projects. GEC and Pollution Probe argued that externalities should be taken into account but that the results of any test incorporating externalities should be positive before a project could proceed.

218

Conclusions

219

4.7.5 The Board observes that, in general, distribution system expansion projects are localized and site specific. The Board has determined that in assessing proposed individual distribution system expansion projects the utilities should not be required to perform additional financial feasibility tests beyond the Stage I test.

220

4.7.6 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 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.

221

4.8 OTHER MATTERS

222

4.8.1 FONOM and NOMA submitted that communities in Northern Ontario should be notified of their right to form co-operatives for the purpose of making applications for approval to distribute natural gas. The Board notes that there is no prohibition in the applicable legislation against a co-operative making application for the necessary approvals to distribute natural gas. However, any such application would have to meet the Board's prefiling requirements and would be subject to the Board's review.

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 223

5. COMPLETION OF THE PROCEEDINGS

224

5.1 THE NEXT PHASE OF E.B.O. 188

225

5.1.1 In Procedural Order No. 4 the Board stated that it had determined that it needed to "deal first with the substantive philosophical differences" between the two groups that were signatories to the ADR Report. Having made its decision on the issues of principle the Board directs the utilities to develop the guidelines and policies set out in this Interim Report and file them with the Board by September 30, 1996. Parties wishing to submit alternative proposals should file the proposals with the Board by October 28, 1996. The Board will issue further procedural orders providing for a form of alternative dispute resolution to be determined and to follow the filing of the alternative proposals.

226

5.2 COSTS

227

5.2.1 The Board has determined that the parties' appropriate and reasonable costs to date should be awarded. Some parties have submitted arguments on costs. The Board orders the remaining parties to submit their arguments on costs within ten days of the release of this Interim Report. Apart from the usual issues that are addressed in arguments on costs, the Board expects the parties to address the issue of which costs are appropriately included in a submission on costs at this stage of the proceeding. The Board will then provide the utilities a further period of ten days to respond to the parties' applications for costs and a further five days for any reply submissions by the parties seeking costs.

DATED at Toronto, August 15, 1996.

Pamela Hardie
Presiding Member

G.A. Dominy
Member

Judy Simon
Member

Was Appendix A, page 1 229

APPENDIXA ISSUES LIST

230

Tests

231

1.

232

(a) What are the appropriate tests for evaluating the economic feasibility of expenditures on natural gas system expansions?

233

(b) For each test:

234

i) What are the appropriate financial, societal and environmental costs and benefits to include?

235

ii) What inputs are common to all three utilities? Should identical values be used for common inputs?

236

iii) Should the test be applied uniformly by all three utilities? If not, what differences are appropriate?

237

iv) Should the impact of variations in the relevant accounting and reporting practices and rates among the utilities be reconciled? If so, how?

238

(c) How should the tests be applied and in what order?

239

(d) Should financial, societal and environmental costs and benefits that accrue beyond the utility's franchise borders be considered? If so, how?

240

(e) Should the costs and benefits of fuel switching be considered? If so, how?

241

Financial Thresholds

242

2.

243

(a) What are appropriate financial thresholds for expenditures on natural gas system expansions?

244

(b) Under what circumstances and to what level might subsidization be appropriate? If there is subsidization what principles should guide decisions about who should benefit and who should pay?

245

(c) Should a standard or threshold be applied to each project? Is it appropriate to apply the standard or threshold to a utility's portfolios of natural gas system expansions?

246

(d) Should any threshold of financial feasibility be applied uniformly within a utility or across the three utilities?

247

(e) Under what circumstances, over what period of time, and to what level might contributions in aid of construction be collected from the primary beneficiaries of an expansion in order to enhance the financial feasibility of the expansion?

248

(f) Should a variety of methods be available for collecting contributions in aid of construction (e.g. one-time charge, rate surcharge, monthly contribution, etc.)? Under what circumstances should a particular method be chosen?

Was Appendix A, page 2 249

Integration Issues

250

3.

251

(a) How should natural gas demand-side management initiatives be considered when determining the need for, timing and scale of, natural gas system expansion projects?

252

(b) Should the tests and financial thresholds for expenditures on natural gas system expansions be consistent with those for natural gas demand-side management expenditures? If not, what differences are appropriate?

253

4.

254

In the route selection process, how should the trade-offs among financial feasibility, societal and environmental impacts, and customer additions in a project be identified and evaluated?

255

Monitoring and Reporting

256

5.

257

(a) How should natural gas system expansions be monitored and reported to the Board?

258

(b) What monitoring and reporting should there be at the project level, portfolio level and on a cumulative basis?

259 (c) How should under- and over-collections of contributions in aid of construction be treated?

Application of Guidelines

260 **6.**

261 What should be the definitions of transmission, distribution, storage, infill, replacement and reinforcement?

262 **7.**

263 (a) What guidelines should result from the Board's deliberations in this matter?

264 (b) How should these guidelines be applied to expenditures on transmission, distribution, storage, infill, replacement and reinforcement?

Excluded Issues

265 **1.**

266 Matters directly related to cost allocation and rate design methodologies, including:

267 the allocation of subsidies among rate classes;

268 any proposals for changes to the existing cost allocation and rate design methodologies;

269 alternatives to contributions in aid of construction and how might they be applied to meet the standards of acceptability for expansion; and

270 matters that are the subject of the Union Gas Limited M12 Cost Allocation and Rate Design Study including the issue of the application of incremental or rolled-in tolling methodology to expansions.

271 **2.**

272 Evaluation of the relative risks (both economic and service) of supply options and DSM alternatives.

3.

Matters concerning the appropriate dollar values for any externality costs or benefits.

Was Appendix A, page 3

4.

Construction and environmental issues contained in the Board's Environmental Guidelines for locating, constructing and operating hydrocarbon pipelines in Ontario.

5.

Issues (a)-(d), (f), (g) and (i) in written submissions of Ontario Pipeline Landowners Association and the Ontario Federation of Agriculture, et al. dated September 8, 1995.

6.

Options available to new communities for gas supply when utilities will not provide service.

7.

Obligation to undertake system expansion within a specific time frame in cases where Board approved feasibility tests have been passed.

8.

Requirement to hold overall gas use or environmental impact to a standard or series of targets.

9.

Recommendations for changes in regulations or laws under the jurisdiction of other parties where there are impacts on feasibility (e.g. power of municipalities to forgive property taxes on gas lines to improve feasibility).

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APPENDIXB E.B.O. 188
UNION, CONSUMERS GAS & CENTRA NATURAL GAS SYSTEM EXPANSION

290

List of Interventions

291

Industrial Gas Users Association ("IGUA")
Consumers' Association of Canada ("CAC")
Ontario Coalition Against Poverty ("OCAP")
Power Workers' Union ("PWU")
Green Energy Coalition ("GEC")
Ottawa-Carleton Gas Purchase Consortium
Canadian Association of Energy Service Companies ("CAESCO")
Natural Resource Gas Limited ("NRG")
Woodland Hills Community Inc. ("Woodland Hills")
Pollution Probe
TransAlta Energy Corporation ("TransAlta")
TransCanada PipeLines Limited ("TransCanada")
The Heating, Ventilation, Air Conditioning Contractors Coalition Inc. (the "HVAC Coalition")
Grenville-Wood
Municipal Electric Association ("MEA")
City of Kitchener
Energy Probe
Ontario Hydro
Northwestern Ontario Municipal Association ("NOMA")
Ontario Native Alliance ("ONA")
Ontario Federation of Agriculture ("OFA")

292

LATE INTERVENORS

293

The British Columbia Ministry of Energy
Mines and Petroleum Resources ("the Ministry")
StampGas Inc. ("SGAS")
Canadian Industry Program for Energy Conservation ("CIPEC")
Ecological Services For Planning Inc.
F & V Energby Co-operative Inc. ("F & V")

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APPENDIXC E.B.O. 188
UNION, CONSUMERS GAS & CENTRA NATURAL GAS SYSTEM EXPANSION

295

Parties Submitting Argument

296

Board Staff
Canadian Industry Program for Energy Conservation
City of Kitchener
Consumers Gas'
Consumers' Association of Canada
Energy Probe
F & V Energy Co-operative Inc.
Green Energy Coalition
Industrial Gas Users Association
Municipal Electric Association
Northern Ontario Municipal Association
Ontario Federation of Agriculture
Ontario Native Alliance
Ontario Coalition Against Poverty
Pollution Probe
Power Workers' Union
Union Gas Limited and Centra Gas Ontario Inc.

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APPENDIXD E.B.O. 188
UNION, CONSUMERS GAS & CENTRA NATURAL GAS SYSTEM EXPANSION

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Parties Submitting Reply Argument

299

Board Staff
CAC
CIPEC
City of Kitchener
Consumers' Gas
GEC
IGUA
OCAP
OPLA & OFA
Pollution Probe
Union Gas Limited and Centra Gas Ontario Inc.

APPENDIXE E.B.O. 188
UNION, CONSUMERS GAS & CENTRA NATURAL GAS SYSTEM EXPANSION

301

List of Concerned Parties

302

Professor S.J. Haynes, Brock University
Mr. R.H. Timms, Fonthill, Ontario
Mr. Brian Coburn, Mayor, Township of Cumberland
Ms. Margaret Jukes, St. Catharines, Ontario
Mr. Walter G. Dickie, Councillor Ward 1, Township of Oro-Medonte
Mr. Gerald A. Dust, Navan, Ontario
Ms. Patricia Sayer, Mayor, Cache Bay Municipality
Mr. Ian Mollett, C.M.A., Chief Administrative Officer, The Town of Parry Sound
Mr. Peter Clark, Regional Chair, Municipality of Ottawa-Carleton
Mr. Ronald K. Stevens, Mayor, Township of Severn
Mr. Wayne Adair, The Corporation of the Township of Temagami
Mr. John Telfer, Assistant to the Clerk, Corporation of the Township of Dymond
Mr. Neal D. Gruntz, Petawawa, Ontario
Ms. Judy Currins, CMO, Clerk-Treasurer Village of Omemee
Ms. Nancy Paish, Deputy Clerk-Treasurer, The Township of Emily
Mr. John DuChene, Clerk-Treasurer, Township of Asphodel
Ms. Margaret Montgomery, A.M.C.T., Clerk Treasurer, Village of Hastings
Mr. Douglas J. Pearcy, Reeve, Corporation of the Village of Norwood
Mr. Guy St-Jean, Reeve, Corporation Du Village De L'Orignal
Ms. Barbara C. Stevens, Clerk-Treasurer, The Corporation of the Township of Alberton
Mr. Julian J. Tofts, CAO, Township of Springwater
Mr. Jean-Claude Trottier, Reeve, Corporation of the Township of Alfred
Mrs. Margaret Duncan, Almonte, Ontario
Mr. Eric E. Collingwood, Clerk-Trasurer/Administrator, Town of Wasaga Beach
Mr. Stanley Draffin, Agincourt, Ontario
Mr. Roman Martiuk, PEng. CMA, CHRP, Chief Administrative Officer, Town of Georgina
Mr. Thomas Edwards, Acting Regional Chair, The Regional Municipality of Durham
Mr. M.G. Wade, P. Eng., Chief Administrative Officer, Township of Ernestown
Mr. Tom Smarda, Unocal Information Campaign
Mr. David Katz, President, Sustainable Resources Management Inc.
Mr. James Hill, M.C.I.P., Acting Planning Commissioner, The Corporation of the County of Oxford
Environment Canada

Ratemaking Principles and the Use of Subsidies in Natural Gas Community Expansion Programs

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March 17, 2016

TABLE OF CONTENTS

1. OVERVIEW

The purpose of this document is to provide technical expertise and response on behalf of the Canadian Propane Association ("CPA") with respect to questions to be addressed in a generic hearing (EB-2016-0004) before the Ontario Energy Board ("OEB") on the topic of considering possible alternative ratemaking frameworks to provide natural gas service to Ontario communities that do not currently have access to natural gas. My expertise is focused on the technical aspects and reasonable application of ratemaking principles; as I am not an attorney, I am not providing legal opinions regarding the legal authority of the OEB or other legal matters.

The OEB intends to review the several issues in the generic proceeding[1]. The following questions having ratemaking implications are addressed in this document:

- 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?
- Should the OEB consider exemptions or changes to the EBO 188 guidelines for rural, remote and First Nation community expansion projects?
    - 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?
    - 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?
    - What, if any, amendments to the EBO 188 and EBO 134 guidelines would be required as a result of the inclusion of any costs identified above?
    - 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?
    - 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?
    - Should the economic, environmental and public interest components in not expanding natural gas service to a specific community be considered? If so, how?
- Should the OEB allow natural gas distributors to establish surcharges for 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?
- How should the OEB incorporate the Ontario Government's recently announced loan and grant programs into the economic feasibility analysis?

The following are summary points relevant to addressing these questions. Greater detail is provided in later sections of this document.

- While subsidizing the expansion of natural gas in any form has the likely outcome of expanding natural gas service beyond what otherwise might occur, such subsidization, especially cross-

[1] Decision and Procedural Order No. 2 EB-2016-0004, March 9, 2016

company subsidization, is inconsistent with long-held ratemaking principles, specifically: 1) benefits follow costs, and 2) there is no harm to ratepayers.

  - In the event where existing customers contribute through their rates to the expansion of service to new customers, benefits (for new customers) do not follow costs (paid by existing customers) and, thus, existing ratepayers are harmed.
  - In the event cross-utility subsidies are permitted, the benefits and costs are further separated and confounded in that the costs are paid by one utility's ratepayers for the benefit of another utility's new customers.

- Legislation, plans, policies and commitments from government encourage the rational expansion of natural gas service and infrastructure and do not prescribe or otherwise advocate rate subsidies.
- The guidelines and economic tests from EBO 188 and EBO 134 ensure that the expansion of a gas distributor's system does not lead to undue rate increases for existing customers. These are consistent with sound rate principles and have worked well for many years. The tests should continue to be used going forward to ensure natural gas expansion is based on sound economics and creates no harm. There is no need for exemptions or changes to these guidelines that would result in uneconomic expansion and subsidies.
- The OEB should allow natural gas distributors to establish surcharges for customers of new communities to recover the costs of expanding service to those communities in a way that follows cost-of-service principles. That is, communities for which all customers are new customers could be grouped into a unique expansion portfolio and made subject to surcharges designed to recover the costs of expanding service to those new customers in the portfolio. This kind of portfolio grouping and surcharge design and collection would improve the feasibility of potential community expansion projects by making sure that the appropriate customers are charged the appropriate costs in a manner that limits uneconomic expansion and subsidies. An acceptable alternative to a surcharge would be to allow customer contributions in aid of construction (CIAC) as was permitted under EBO-134. In the CIAC instance, some portion of expansion costs are paid up-front by those customers who benefit from the new natural gas service.
- The OEB should incorporate the Ontario Government's recently announced loan and grant programs into the economic feasibility analysis for expansion. To the extent that such loans or grants reduce or offset investment or costs that would otherwise be borne by new or existing ratepayers, the impacts should be reflected in the PI analyses.

2. THE MERITS OF SUBSIDIZATION

- Question: 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?

It is first important to address the appropriateness of subsidies in general and then to address cross-utility subsidies specifically. While subsidizing the expansion of natural gas in any form has the likely outcome of expanding natural gas service beyond what otherwise might occur, such subsidization is inconsistent with long-held ratemaking principles, specifically: 1) benefits follow costs, and 2) there is no harm to ratepayers.

In the event where existing customers contribute through their rates to the expansion of service to new customers, benefits (for new customers) do not follow costs (paid by existing customers). Basing rates on the cost-of-service is the most generally-accepted and widely held principle of ratemaking. When rates are based below the cost-of-service, subsidies and inequities result creating winners and losers and debate among the policy makers who support or oppose the subsidies. The baseline from which the debate takes off is commonly the cost-of-service. In the instance of existing natural gas customers paying higher rates to subsidize the cost of expanding service to new gas customers, this is a clear deviation from cost-of-service principles in favor of the social objective of providing natural gas service to more customers, even when the new service is uneconomic.

There is no doubt that the subsidy provided by existing customers through their rates defines the harm to those ratepayers. While the harm may be characterized as minimal to a single ratepayer, e.g., perhaps only a couple of dollars per month, as a group the numbers become large and more significant. Further, policies deviating from cost-of-service principles can become a slippery slope as attractive social policies, even unrelated, can pile up to create rates and rate structures that eventually bear little resemblance to the underlying cost-of-service.

- 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?

The current PI provisions within EBO 188 and EBO 134 are sufficient.

The OEB has established many relevant precedents for relying upon the ratemaking principle of basing rates on cost-of-service. EBO 188 is noteworthy by setting forth an economic test to evaluate a proposed expansion of a gas distributor's distribution system to ensure that undue rate increases do not occur. The key principle behind the Profitability Index (PI) test is that a total portfolio of expansion projects should not create an increase in rates to existing customers over the long term. This allows for a mix of profitable and unprofitable projects within a given portfolio. The OEB also sets limits as to how unprofitable a single project can be. In the instance of a low PI, distributors can request new customers to pay to offset costs.

EBO 134 includes second and third stage tests that expand the definitions and limits of cost-effectiveness by permitting consideration of additional benefits, costs and social considerations. In the end, subsidies are not to cause an undue burden on any individual, group or class.

The OEB has employed a "no harm" test in evaluating impacts of decision alternatives in situations such as Mergers, Acquisitions, Amalgamations and Divestitures (MAADS).[2] The "no harm" test consists of a consideration as to whether a proposed transaction would have an adverse effect relative to the status quo in relation to the OEB's statutory objectives. These objectives include concepts such as protecting the interests of consumers and promoting economic efficiency and cost effectiveness.

In cases of acquisition in which the OEB has applied this "no harm" test, special consideration has been given to any purchase price premium.[3] Premiums paid over the net book value were not permitted to be recouped through the ratepayers and were, as stated by the utility, "not included in its distribution revenue requirement". This price premium parallels the subsidization of gas extension portfolios with a PI below 1.0. If the OEB were to allow portfolios with a PI below 1.0, the additional costs above the expected revenue would be analogous to allowing the recovery of a purchase price premium in rates. The OEB's policy with respect to treatment of purchase price premiums is very clear and, similarly, any shortfall arising from portfolios with a PI below 1.0 should not be recovered from other ratepayers.

By relying upon the principles of basing rates on costs and no harm to ratepayers, the OEB is performing the role of facilitating rational natural gas expansion and ensuring that there is no undue cross-subsidization between existing and new customers. The OEB should continue to apply the principles and policies of EBO 188 and EBO 134. Departure from the economic testing prescribed in EBO 188 and EBO 134 should result from government policy as opposed to OEB discretion.

In the event the OEB authorizes cross-utility subsidization to occur, such that customers of one utility subsidize the expansion undertaken by another distributor, the OEB can mitigate some of the adverse impacts by removing the "return" (on rate base) component embedded in the subsidy so that there is only a return "of" and not "on" the capital investment associated with the expansion. With the return component removed, utilities will continue to benefit from the remaining non-financial, social and other benefits of natural gas expansion.

- 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?

The economic assessment should allow for consideration of all or any quantifiable costs and benefits, including opportunity costs. For example, there are potential unintended consequences and adverse impacts of expansion of natural gas to rural areas, such as adverse impacts on alternative fuel suppliers (e.g., propane) and existing propane customers who are close to, but do not have access to, the natural gas expansion program. These customers could be harmed by propane price increases (if propane suppliers attempt to recover fixed costs over a smaller customer base) or worse, lose their access to propane if their suppliers cease service. Such impacts, i.e., costs, should be reflected in the PI analyses, subject to some party submitting cost data, assumptions, etc.

- What, if any, amendments to the EBO 188 and EBO 134 guidelines would be required as a result of the inclusion of any costs identified above?
- 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?

[2] Decision and Order (Combined Proceeding RP-2005-0018/EB-2005-0234/EB-2005-0357)
[3] Decision and Order EB-2014-0217

- 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?

The OEB should not prescribe any exemptions to EBO 188 guidelines, EBO 134 guidelines or related amendments. The primary and guiding standard of EBO 188 is the requirement that the portfolio PI be greater or equal to 1.0; anything within the portfolio that deviates from that is less important, as long as the portfolio is at or above PI=1. The creation of amendments or exemptions to these guidelines, which already provide sufficient purpose, measures and flexibility, will tend to conflict further with cost-of-service principles and increase the quantity and distance between winners and losers.

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

The ability to propose the consideration of opportunity costs in the PI tests allows for all perspectives and views on costs, benefits and policy.

3. CONSIDERING CHANGES AND DEVIATIONS FROM EBO 188

- Should the OEB consider exemptions or changes to the EBO 188 guidelines for rural, remote and First Nation community expansion projects?
    - 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?
    - 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?
    - What, if any, amendments to the EBO 188 and EBO 134 guidelines would be required as a result of the inclusion of any costs identified above?
    - 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?
    - Should there be exemptions to certain cost 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?
    - Should the economic, environmental and public interest components in not expanding natural gas service to a specific community be considered? If so, how?

Legislation, plans, policies and commitments from government encourage the expansion of natural gas service and infrastructure.

- The Ontario Energy Board Act, 1998, includes the following as part of its guiding principles:
    - To facilitate competition in the sale of gas to users.
    - To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
    - To facilitate rational expansion of transmission and distribution systems.
- “Achieving Balance – Ontario’s Long-Term Energy Plan” includes the following summary point regarding natural gas expansion: “The government will work with gas distributors and municipalities to pursue options to expand natural gas infrastructure to service more communities in rural and northern Ontario.”
- In his February 17, 2015, letter to the OEB, the Ontario Minister of Energy wrote, ”I appreciate your continued support to ensure the rational expansion of the natural gas transmission and distribution system for all Ontarians.”

While clearly statements advocating natural gas expansion, none of them go so far as to advocate the subsidy or uneconomic expansion of natural gas to the benefit of one group of ratepayers or businesses at the harm of other ratepayers or businesses. In practice and in word, government policies prescribing what is “rational” and “reasonable” clearly seek “no losers” and “no harm.”

The guidelines and economic tests from EBO 188 and EBO 134, administered by the OEB, ensure that the expansion of a gas distributor's system does not lead to undue rate increases for existing customers. These are consistent with sound rate principles and have worked well for many years. The tests should continue to be used going forward to ensure natural gas expansion is based on sound economics and creates no harm. There is no need for exemptions or changes to EBO 188 that would result in uneconomic expansion and subsidies.

As EBO 188 prescribes, a portfolio of projects achieving a PI of 1.0 is economic and acceptable. Allowing a portfolio of PI<1.0 permits a subsidy by definition. In order to remain consistent with cost-based ratemaking principles and the principle of "no harm," the basic formula from EBO 188 should not change. The types of benefits and costs considered should likewise remain unchanged. It is possible to amend the simple PI formula with estimates of social, environmental, and other benefits and costs, and the second and third stage tests in EBO 134 consider such amendments. But such complexities are subject to unreasonable and contentious claims and assumptions. In summary, the PI>1 test should remain as the standard.

4. SURCHARGES TO RECOVER COSTS OF EXPANSION

- Question: Should the OEB allow natural gas distributors to establish surcharges for 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?

The OEB should allow natural gas distributors to establish surcharges for customers of new communities to recover the costs of expanding service to those communities in a way that follows cost-of-service principles. That is, communities for which all customers are new customers could be grouped into a unique expansion portfolio and subject to surcharges designed to recover the costs of expanding service to those new customers in the portfolio. This approach would match the cost of expansion in a community to those new customers in that community who will benefit from the community expansion program. This kind of portfolio grouping and surcharge design would improve the feasibility of potential community expansion projects by making sure that the appropriate customers are charged the appropriate costs in a manner that limits uneconomic expansion and subsidies.

Surcharges that follow cost-of-service principles will protect against undue burden on any individual, group or class, and ensure no harm.

5. GRANTS AND LOANS

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

Financial support from the Ontario Government in the form of economic development grants and interest free municipal loans can have a substantial effect on improving the economics of natural gas community expansion programs. Grants and loans from these funding sources should be included in the economic analyses and formulae consistent with EBO 188 and EBO 134, as these funds will displace the investment and interest costs that otherwise would be needed from the utility, ratepayers or new gas customers. The funding sources and associated cost reductions will have a positive impact on PI scores and more expansion portfolios will be judged as cost-effective.

Alternative programs, policies and practices that encourage natural gas expansion, such as the recently announced loan and grant programs, do not involve rate subsidies or deviation from cost-of-service principles. Many of these are already in practice and effective in Ontario or the United States. These kinds of innovations and support are driven and provided by governments entitled to make such policy choices as part of an overall energy strategy, as the active promotion of natural gas at the detriment of alternative sources of energy are beyond the authority of most public utility commissions.

The OEB should incorporate the Ontario Government's recently announced loan and grant programs into the economic feasibility analysis for expansion. To the extent that such loans or grants reduce or offset investment or costs that would otherwise be borne by new or existing ratepayers, the impacts should be reflected in the PI analyses.

Charley Budd

Director

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Chicago, IL
Direct: 312.583.4135

Professional Summary

Charley Budd is a Director in the Energy Practice in Navigant Consulting's Chicago, Illinois office. He has extensive rates and regulatory experience, as well as energy efficiency, demand response experience, at large utilities and consulting firms. His consulting experience includes energy efficiency program planning and implementation for multiple utility and other industry clients; U.S. and international.

Representative Experience

As Electric Pricing Director for a large Michigan utility, managed a department responsible for rate design, cost-of service, fuel clauses, and related regulatory interfaces. Testified before the Michigan Public Services on several topics, including demand-side management cost reconciliation (Case U-10554), integrated resource planning (Case U-9346), competitive bidding (Case U-9586) and market research (Case U-8871).

As Gas Pricing Supervisor for a large Michigan utility, supervised a section responsible for rate design, cost of service, a $900 million gas fuel clause and related regulatory interfaces. Testified before the Michigan Public Services on several related topics, including gas supply planning and rate design (U-8055), gas cost reconciliation (U-8055R), and several gas rate refunds (U-8091, U-8239, and U-8300).

Mr. Budd has developed and utilized several types of electric and gas cost-of-service studies as part of the regulatory and rate design processes including, utility rate increases and refunds, special promotional rates and services.

Mr. Budd earned an MBA in Marketing from Michigan State University, and a B.S. in Business Economics & Public Policy from Indiana University. He also served several terms on the Board of Directors for the Midwest Energy Efficiency Alliance (Vice Chairman) and the Association of Energy Services Professionals (Secretary). He is a past instructor on the topic of cost-of-service at the EEI Advanced Rate School.

Work History

Director, Navigant Consulting, Inc.

Principal, DNV GL, Inc.

Director, Exelon Corporation

Electric Pricing Director, CMS Energy Corporation

Gas Rates Supervisor, CMS Energy Corporation

Professional Associations

Past Board Member, Vice Chairman MEEA

Past Board Member, Secretary AESP

Past Member, AGA Communications Committee

Honors and Fellowships, Thought Leadership

2006 Exelon's Chairman Award for Stewardship

Taught Advanced Cost of Service session at Edison Electric Institute's Advanced Rate School

Taught Advanced Program Implementation for the Association of Energy Services Professionals

Over a dozen publications and presentations in electric and gas industry journals and seminars

Education

M.B.A., Marketing	Michigan State University
B.S., Business Economics & Public Policy	Indiana University

FORM A

Proceeding:.....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Charles R Budd (*name*). I live at Naperville (*city*), in the state (*province/state*) of Illinois .

2. I have been engaged by or on behalf of McMillan LLP (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date March 17, 2016

Signature

Guidelines for Gas Expansion in Ontario

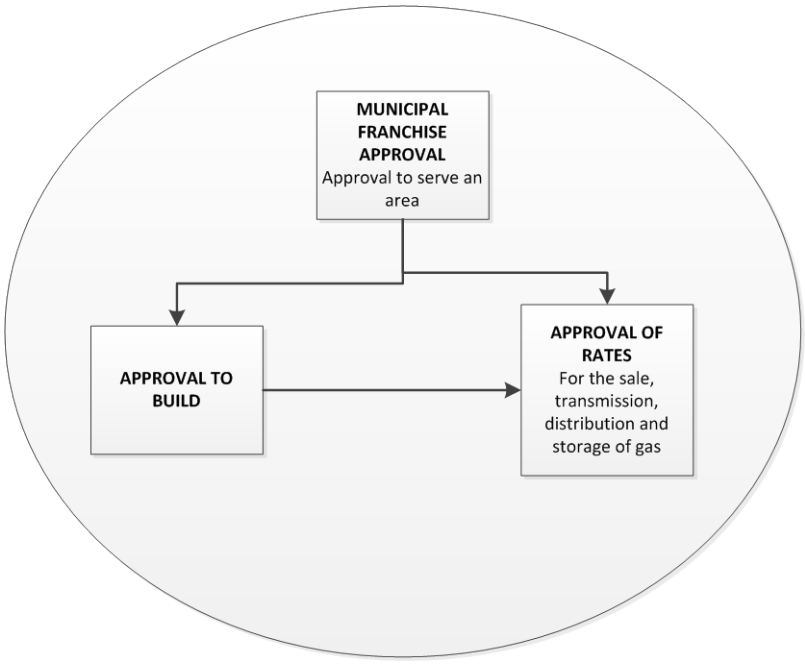
SUMMARY

The Ontario Energy Board (OEB) is an independent and impartial public agency. We make decisions that serve the public interest. Our goal is to promote a financially viable and efficient energy sector that provides you with reliable energy services at a reasonable cost.The OEB is governed by a number of statutes including the *Ontario Energy Board Act, 1998* (OEB Act). In carrying out our mandate we have a number of objectives including protecting consumers' interests and ensuring the viability of Ontario's natural gas and electricity sectors. To achieve this balance we must ensure that the rules and regulations are applied fairly and consistently.

With respect to natural gas, the OEB has a broad mandate which includes approving natural gas rates; issuing gas marketer licenses, approving the construction, expansion or reinforcement of pipelines, approving the designation of gas storage facilities, reviewing applications for well drilling and providing reports and recommendations to the Ministers of Natural Resources and of Energy. Furthermore, the OEB approves municipal franchise agreements and applications for certificates of public convenience and necessity for construction of works to supply gas.

These Guidelines are intended to act as a reference for companies that are interested in distributing natural gas in the province of Ontario. They are divided into three sections:

1. **Municipal Franchise Approval** - Securing the approval to serve an area of the Province
2. **Leave to Construct** - Securing approval to construct facilities that meet certain size and cost criteria
3. **Rate Setting** Securing approval to charge customers for regulated services

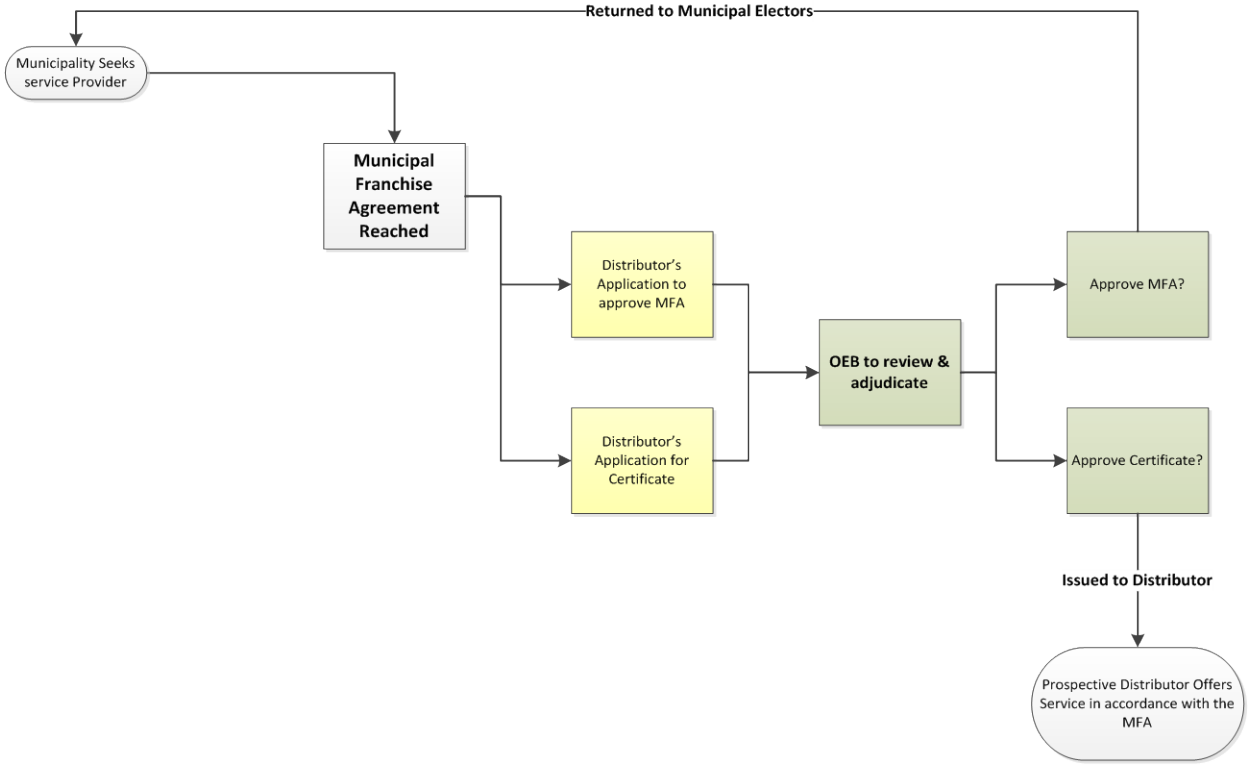


The provisions of the *Municipal Franchises Act* and the OEB Act give the OEB the authority to approve municipal franchise agreements (MFA), to issue certificates of public convenience and necessity (Certificate) for the construction of works to supply gas and to set the rates consumers pay for the distribution and transmission of natural gas. Section 36 of the OEB Act states that no person may sell gas or charge for the distribution, storage or transmission of natural gas in Ontario, without the approval of the OEB. However, section 36 does not apply to the sale, transmission, distribution or storage of gas by a distributor who distributes less than 3,000,000 cubic metres of gas annually.

The following is a summary of some of the instruments and related documents that provide the framework for the regulation of natural gas distribution in Ontario.

1. MUNICIPAL FRANCHISE APPROVAL

Municipal franchises are governed by the *Municipal Franchises Act*. The requirements for acquiring a franchise include securing a MFA with the municipality that you are intending to serve, approval of that MFA from the OEB and a Certificate from the OEB. Descriptions of the process for obtaining an MFA (and approval) and a Certificate are summarized below.



Municipal Franchise Agreement

The MFA is an agreement between a municipality that wants to have a gas distribution system installed within its boundaries and a natural gas distributor that wants to provide that service. The MFA must be submitted to the OEB for approval under section 9 of the *Municipal Franchises Act*. To standardize the format and content of MFA's the OEB, with input from municipal leaders, developed the Franchise Handbook and a Model Franchise Agreement. The purpose of the Model Franchise Agreement is to provide 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*. The Model Franchise Agreement and Franchise Handbook can be found on our website.

Certificate of Public Convenience and Necessity

Under section 8(2) of the *Municipal Franchises Act*, prior to constructing works to supply gas, a gas distributor must apply to the OEB for a Certificate. If the OEB approves the application it will issue a Certificate to the gas distributor. The exact area within a municipality where a gas distributor is permitted to construct gas works is defined by the OEB's Certificate .

Typically the gas distributor will submit to the OEB a signed MFA for approval and an application for a Certificate at the same time.

The role of the OEB is to adjudicate on the application. The OEB's hearing process starts with a notice to the public and interested parties inviting them to participate in the hearing or to write a letter with any comments. Once the OEB considers all of the evidence before it, including providing for questions on that evidence and any written submissions, the OEB makes a determination as to whether or not to approve the MFA and issue a Certificate.

It is important to note that while a MFA may, by contract, give a gas distributor the right to construct gas works and to supply gas within municipal boundaries the MFA does not, in and of itself, grant exclusive rights to the gas distributor. The OEB may authorise multiple gas distributors to operate within a single municipal boundary. A Certificate must be granted by the OEB before any works can be constructed or natural gas supplied, even if a signed MFA exists.

With OEB approval two gas distributors could potentially operate within the boundaries of the same municipality, although they would not serve the same customers. For example, gas distributor A could have a pipeline bordering on the west side of a municipality and it could construct gas works to serve consumers on the western side of the municipality while a different gas distributor B could have a pipeline and associated works that serve consumers on the eastern side.

2. LEAVE TO CONSTRUCT

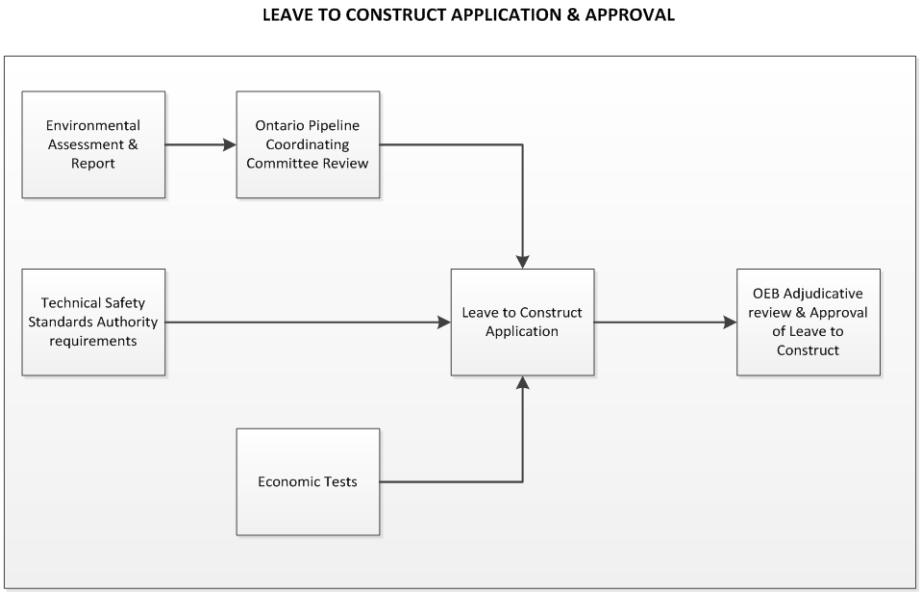
Construction of a hydrocarbon distribution line that meets any of the following criteria requires that the gas distributor apply for a leave to construct and secure approval from the OEB (OEB Act section 90):

- the diameter of pipe is 12 inches or greater
- an operating pressure of an amount equal to greater than 2,000 kilopascals
- the cost of project is greater than or equal to $2,000,000
- the length of pipe required exceeds 20 km

A number of supporting filings are required. They include:

a) Environmental Assessment and Report (ER)
b) Review by the Ontario Pipeline Coordinating Committee
c) Any required approvals and permits from the Technical Safety Standards Authority
d) A map of the proposed pipeline and the form of any landowner agreements
e) Economic Considerations
    i. EBO 188 - for gas distributors that currently have a customer base in Ontario
    ii. EBO 134 – economic test

The OEB will adjudicate the application either through written or oral hearing .



(a) Environmental Report

Gas distributors must complete an environmental assessment and submit an ER to the OEB. The term "environment" includes natural, social, economic, cultural and built components.

The OEB developed the *Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario* (Guidelines) and updates it periodically. The Guidelines should be considered by a gas distributor in preparing the Environmental Report.

(b) Ontario Pipeline Coordinating Committee (OPCC)

The OPCC provides a single point of contact to identify provincial environmental concerns related to natural gas distribution, transmission and storage proposals and raises those concerns with project

applicants. The OPCC is made up of government ministries and agencies that have a role in reviewing natural gas distribution, transmission and storage facility projects. The OPCC reviews environmental assessment and routing reports prepared by the applicants before they apply to the OEB to have projects approved with a view to minimizing any negative environmental impacts that could arise from these projects by. The mandate of the committee and the steps of its review are set out in the Guidelines.

(c) Technical Safety Standards Authority

The Technical Safety Standards Authority (TSSA) is the technical authority that has quality and safety accountability for the construction and maintenance of pressurized systems such as natural gas distribution. They operate under the authority granted to them under *Technical Safety Standard Act, 2000*, and Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)[1]. The TSSA is an independent agency, and is not affiliated with the OEB. If the OEB approves a leave to construct application it is generally conditional upon the distributor's compliance with all applicable regulatory requirements including those related to safety and integrity under the TSSA mandate and legislation.

(d) Land Matters

Under the OEB Act (section 94) an applicant that has applied for leave to construct a pipeline must file a map showing the general location of the proposed work which includes the municipalities, highways, railways, utility lines and navigable waters that the pipeline will go through, over, under, upon or across.

An applicant is also required to file with the OEB a copy of all forms of land agreement that it has or will offer to each owner of land that will be affected by the proposed route. The OEB must approve the form(s) of agreement (OEB Act section 97).

In addition to the right to construct the facilities, a leave to construct approval granted by the OEB entitles the applicant and holder of that leave to other rights under the OEB Act, including the right to:

- enter on the land to conduct surveys and examinations that are necessary to prepare the site for the work provided that any damages resulting from entry on the land are agreed upon or determined under the *Expropriations Act* (OEB Act section 98);
- seek an expropriation order from the OEB for land related to the proposed work in the absence of an agreement with the owner(s) of such land (OEB Act section 99).

[1] Schedule G - TSSA 2000 - Ont Regulation 210-01 Oil and Gas Pipeline Systems

(e) Economic Considerations for Gas Expansion-

Two OEB issued documents, EBO 188 and EBO 134, should be considered by a gas distributor when planning to expand access to gas or to establish new natural gas systems. The first document is for distribution pipelines whereas the second one is for transmission pipelines. These documents describe some of the financial thresholds that these natural gas expansion plans need to meet. The OEB's role here is to facilitate rational natural gas expansion; and ensure that there is no undue cross-subsidization between existing and new customers.

The description of how the requirements in these documents are met forms part of the evidence filed in a leave to construct application to the OEB. . The OEB wishes to ensure that the expansion of a gas distributor's system does not lead to undue rate increases for existing customers.

EBO 188 describes the economic test that should be used to evaluate a proposed expansion of a gas distributor's distribution system to ensure that these undue increases do not occur. The key principle behind the test is that total portfolio of expansion projects should not lead to a rise in the rates of existing customers over the long term. This allows a distributor to propose an expansion portfolio that blends projects with customers that are less costly to serve with those that are more costly. The OEB also sets a limit as to how unprofitable a single project can be. In cases where a project is below the feasibility threshold, the distributor may ask the new customers to pay to offset the additional costs.

EBO 134- directs all gas distributors to use Discounted Cash Flow (DCF) method as a minimum test in assessing the feasibility of expansion projects.

3. Rate Setting

One of the key mechanisms that the OEB has to protect consumers is regulating the rates that gas distributors charge (OEB Act section 36). The test that the OEB applies to the rates that the gas distributor applies for must be just and reasonable.

As the energy regulator, the OEB sets the rates that gas distributors are allowed to charge their customers for:

- gas supply (unless the consumer purchases directly from a retailer)
- transportation and delivery
- storage

The Minimum Filing Requirements for Natural Gas Distribution cost of Service Applications (EB-2005-0494) provide a standard by which the distributor applications for cost of service rates must be developed and filed. Applications will not be considered complete and will not be processed until the minimum filing requirements are met.

Delivery and storage rates are adjusted annually based on a Board-approved method. Gas supply related costs are adjusted every three months based on the OEB's Quarterly Rate Adjustment Mechanism (last updated in EB-2008-0106).

Remarks by Guy Jarvis

President, Enbridge Gas Distribution

Ontario Energy Network

June 19, 2013

Toronto, Ontario

Check against delivery

It's my pleasure to speak at the Ontario Energy Network. This luncheon series has become a real tradition at the Fairmont – and that's saying something given the venue's history. I'm told this building is actually the third hotel to stand on this site – each meeting the evolving needs of the community over time.

In a way you could say that gas utilities like Enbridge Gas Distribution, which provides energy to this building and many others in the downtown core, are entering a third stage in their own history. Our utility first served businesses along King Street with gas manufactured from coal in the 1800s. In the 1950s, we switched to natural gas mainly from Alberta. And today, while western supplies remain important, natural gas from shale formations in the U.S. northeast also travels through our pipes. These new sources of natural gas have been driving dramatic changes in North America and reshaping natural gas markets around the world over the past decade.

Our two million customers are already benefitting from these changes to the tune of $400 a year in savings on average for residential customers compared to natural gas prices five years ago. In total, the average annual energy savings for Ontario homes and industry is estimated at about $4 billion. I would encourage you to stop and think about that number for a second. That is $4 billion a year in energy savings that Ontario families and businesses can invest and spend elsewhere in our economy. And with more than 100 years' worth of natural gas reserves estimated in the ground, Moody's recently stated what others already have – natural gas prices will continue to remain stable for the foreseeable future.

So how will Ontario capitalize on natural gas? Too often, energy plans in Ontario have focused much more on electricity than gas. But competitive and stable-priced natural gas can play an increasingly critical role in Ontario's energy future.

The Province's decision to phase out coal-fired generation was a big decision and a strong statement. As the province undertakes the announced review of Ontario's Long-term Energy Plan, the government needs to make another big decision and strong statement…a statement that ensures that the value of safe, reliable, and affordable natural gas is a larger part of provincial energy, economic, transportation and environmental planning.

Ontarians want clean and affordable energy options and natural gas offers solutions, particularly in the areas of local electricity generation, expansion into communities currently not served by natural gas and transportation.

New gas supplies are driving a revolution in the natural gas sector, not just here in Ontario but around the world. This new energy landscape presents us with options that were not fully available or recognized when our province's current Long-term Energy Plan was released. When then Energy Minister Brad Duguid presented the plan, it envisioned a strategic role for natural gas as a support for intermittent renewables, as a back-up while nuclear plants are modernized and as a player in some planned combined heat and power projects.

Those roles remain important, but the dynamic around us opens the door to new and deeper opportunities – opportunities that are already being pursued by others beyond our borders. As the province prepares to review its energy plan, Enbridge is encouraging the government to recognize the broader opportunities natural gas presents the province – particularly from an economic and an environmental perspective.

Today I will outline just three key opportunities and propose timely actions for the government to consider. Actions that I believe will allow Ontario to fully benefit from the natural gas revolution in the long-term.

I know that many of you are familiar with today's dramatically changing natural gas supply dynamics, particularly in North America, so I'll just start by touching on this for context briefly.

A number of significant, new economic natural gas shale basins are on our doorstop. The nearby Marcellus and Utica shale formations which stretch across Ohio, Pennsylvania and New York State are already changing gas flows to Ontario. TransCanada has reversed the flow of a pipe that once moved gas into the U.S. It now brings gas into the province through Niagara and the natural gas industry is considering additional ways to ensure that Ontario can further benefit from these new sources.

Enbridge believes that industry best practices in combination with strong regulation will ensure that natural gas continues to be produced safely. And we support strong regulation to ensure that this happens.

In Illinois, a Bill to allow hydraulic fracturing was written in consultation with industry and environmental groups including the Sierra Club. It is considered by many to be the strictest regulation in the U.S. and outlines standards for setbacks from water sources, construction, waste water storage, water monitoring and chemical disclosure. Shale deposits are also found in many other parts of the world and the movement of natural gas is changing elsewhere as well.

One need not look further than the market for liquefied natural gas to get a sense of the sea change that is underway. According to the American Gas Association, following the 2011 Fukushima nuclear disaster LNG use has increased significantly and now delivers almost half of Japan's energy. After the discovery of 100 trillion cubic feet of natural gas offshore, Mozambique has embarked on a plan to build a floating liquefaction facility. And when it opens in 2015, LNG shipments are expected to be one of the largest sources of growth from the $5.25 billion Panama Canal expansion currently under construction.

The natural gas supply revolution clearly extends well beyond our borders. To ensure that we remain economically competitive, we must take advantages of the opportunities that these changes make possible for Ontario.

The first opportunity I'd like to talk about is power generation.

Today, natural gas fired generation plants are already delivering clean, competitively-priced electricity to Ontario consumers. Unfortunately most people in Ontario have probably heard more about the controversial siting of two large gas-fired plants than the positive role that natural gas is playing in the province. And it's too bad because it's a great story to tell.

Canada is moving toward alternative energy sources – which will happen over the course of the coming decades – and natural gas is helping to make that happen. Since Ontario announced its green energy plan, Ontario has added 5,000 MW of natural gas fired generation to the provincial grid compared to 1,500 MW of renewables. It has been central to Ontario's move away from coal.

The competitive price of natural gas combined with the high efficiency and flexible operating capability of gas fired units suggests that the opportunity should exist in all segments of the province's power demand profile – baseload, intermediate and peaking. There are also other approaches to generating electricity and we would like to see a key role for natural gas there too.

I recently spoke at the Economic Club of Canada in Ottawa with an executive from AGL Resources, the largest natural gas distribution utility in the United States. He spoke about an Executive Order issued by President Obama last year on the topic of combined heat and power or CHP. The order established a national goal of 40 gigawatts of new combined heat and power capacity by 2020 – a 50% increase.

To put that in further perspective, it's 20% more than the total installed capacity of all the generation in Ontario. The White House estimates that nationwide, achieving its goal will save money, generate new capital investment, create jobs, and reduce emissions.

So the question is, what can CHP do for Ontario?

With natural gas prices currently low and expected to remain stable for the foreseeable future, CHP may help address siting issues while at the same time increasing reliability, increasing efficiency and reducing costs.

CHP needs to be a part of the province's Long-term Energy Plan moving forward. It can help address urban electricity supply constraints because it's smaller scale and the technology also uses waste heat, driving significant efficiency gains.

Small CHP applications located in urban centres facing supply constraints can help to eliminate the need for new large-scale transmission infrastructure which is very costly and controversial. These CHP generators have a much smaller footprint than other forms of generation – they can often fit on a transport truck - so they can be built within buildings located in established areas.

A CHP application can also produce 30% fewer carbon dioxide emissions compared to a combined-cycle plant. Consider also that CHP can be commissioned in less than half the time it takes traditional central plant-transmission-based generation capacity. This valuable feature should be taken into consideration in the Province's Long-Term-Energy-Plan.

Institutions and businesses can now install small CHP generators to save on costs, improve reliability and provide locally-generated electricity to address urban supply constraints. Beyond the economic and environmental benefits, more CHP generators in strategic institutions such as hospitals and universities can help improve energy resilience in the event of a major electrical outage. Take for example, New York, where during Hurricane Sandy 50% of the city's hospitals suffered a complete loss of power. Yet, not one hospital equipped with a CHP unit suffered a failure. Great performance from CHP units, and it came at a time of great need.

By increasing the number of decentralized CHP applications in its long-term energy plan, the government can further integrate natural gas into the electricity planning process, enhance grid resilience, and better prepare the province in the event of major prolonged grid outages.

The role of natural gas also extends beyond electricity generation. Natural gas can also displace more expensive and more carbon intensive fuels within our homes and businesses. Enbridge continues to receive enquiries from communities not currently served by natural gas asking if our system could be extended.

It's no wonder. Municipalities served by natural gas often use the cost benefits of the fuel as an economic marketing tool to attract new investment. Although many communities are benefiting from clean and affordable natural gas, there are still many individuals and businesses in Ontario who do not yet have that choice.

Expansion of the natural gas distribution network into communities not yet served by natural gas represents another opportunity. We are working on plans for the possible expansion of our distribution system to some of these new communities so that more Ontarians can benefit from gas and so too is our fellow utility Union Gas. In fact, they are looking at the potential role of bringing LNG into some communities where the cost of building a pipeline is prohibitive.

The reasons are clear. Price differentials between natural gas and other home and water heating fuels mean a town with 1,000 homes could collectively save more than $2 million a year on energy costs. On an individual basis, there is trapped economic benefit in the pockets of those without access. For example, a typical household using electricity, propane or heating oil is paying as much as $2,500 more annually for home and water heating compared to those using natural gas from Enbridge.

And for business, expanding access to natural gas may help some newly served communities lower energy costs, help attract investments to create jobs and spur new industries. Beyond the economic benefits, allowing homes and businesses the choice to move away from dirtier sources of energy, such as heating oil, will reduce emissions and benefit the local environment.

Now I know that many people in this room represent hydro utilities so I want to be clear that I am not proposing that we extend the gas grid to all rural areas in Ontario. What I am suggesting is that we look at opportunities where natural gas makes economic sense and may even be able to help local utilities by displacing some load.

The government should not pick the fuel. Selection should be based on the need and what's available. I'm confident that if it's considered objectively, natural gas will find a strong place in the energy mix.

The third area I want to touch on is natural gas for transportation because it provides another enormous area of opportunity for the Province to meet its economic and environmental goals.

This is one area that warrants the attention of the province in broader energy and transportation policy planning. Both compressed and liquefied natural gas for transportation represent a significant opportunity for the province to tackle its economic competitiveness issues by drastically reducing fuel costs for heavy transport and return-to-base fleets. And more importantly, it can help address its environmental goals through reduced greenhouse gas emissions and smog-causing particulate matter.

Natural gas vehicles can help improve Ontario's competitive position by providing a fuel cost savings to fleet operators of up to 40%. This is a competitive transportation fuel option that some of our province's competitors in the global marketplace envy, yet we see little movement to embrace this opportunity. We estimate that if just 10% of Ontario's vehicles converted to natural gas it would result in $1 billion in annual fuel savings.

In his recent annual review of Ontario's climate change action plans, the province's environmental commissioner highlighted the need to incorporate greenhouse gas reductions into the long-term energy plan and called out transportation reductions as a key area for attention.

Natural gas can be a big part of that solution. It's cleaner than diesel and can significantly lessen the emissions burden on urban air sheds with 20% greenhouse gas emission reductions. The technology is here. And it's proven.

We are not advocating for the conversion to natural gas in place of electric vehicles. Rather, we encourage the government to embrace a broader "clean vehicle policy" that includes natural gas for

medium to heavy duty vehicles that cannot be economically electrified. The transportation sector represents the largest source of emissions in the province. As a result, natural gas for transportation can help Ontario reach its emissions reduction targets with focused and limited government support for truck conversions and fueling infrastructure.

I cannot think of a greater opportunity to both reduce emissions on a broad scale while improving the province's economic position. The U.S. is already moving ahead in the area of natural gas for transportation. And it's already looking beyond return-to-base fleets and long-haul trucks to smaller applications such as agricultural tractors as well.

In Europe, there is also keen interest in natural gas for transportation. An LNG Blue Corridor project is proposed to improve air quality and reduce greenhouse gas emissions by displacing diesel for medium and long distance transportation. Here in Canada, CN is testing locomotives fueled by natural gas in northern Alberta. And we are seeing the market drive some fleet conversions in Ontario, but some limited support by the province for this initiative could vastly speed up the process.

If Ontario is to remain competitive and reduce greenhouse gas emissions, we must look seriously at the natural gas for transportation opportunity and not let it pass us by.

There are clear benefits that can be achieved if Ontario's updated long-term energy planning includes a greater focus on natural gas, particularly for electricity generation, community expansion and transportation.

But how do we get there?

Power generation planning needs to be done without picking fuels. Natural gas should be allowed to compete on its own merits in all segments of the province's generation needs. And the plan should also include a larger focus on the strategic use of CHP to address supply issues.

We encourage the government to consider supporting the expansion of the natural gas distribution system as a way of reducing energy costs and bringing cleaner energy to new communities by including support for this approach in the updated Long-term Energy Plan.

And lastly, the province needs a broader transportation policy that supports a range of low carbon vehicles, including, electric, hybrid and natural gas. We encourage the government to work with industry to find ways to make this happen.

In conclusion, natural gas is providing great value to the province right now.

With significant new opportunities presented by a natural gas supply revolution, Ontario must ensure that its updated Long-term Energy Plan is a true energy plan fully considers all that natural gas has to offer. Whether it's for electricity generation, transportation or expanding the distribution system, natural gas can be a solution.

You will notice common themes in the solutions being put forward by the gas sector. We are not advocating the mass expansion of natural gas infrastructure. We recommend using natural gas more strategically to help address two of the province's biggest challenges – the economy and the environment.

To reiterate, I'm not suggesting that the government pick the fuel. Natural gas should be considered fairly alongside other options.

Whether it is evaluated by economic or environmental measures it's my belief that, if allowed to stand on its merits, natural gas will find a greater place in the provincial supply mix for the benefit of the province and its residents.

The province and others in the industry have my commitment that we are here to work with you to help ensure that Ontario benefits from the best energy, economic, transportation and environmental solutions that natural gas has to offer.

Thank you.

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EB-2016-0004
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ENERGY

INTERVIEW WITH STEVE BAKER

IBR talks with Steve Baker, president of Union Gas, on the company's operations, and the expansion of Canada's second largest natural gas utility.

March 31, 2015 | Nicholas Zeeb

IBR: As Canada's second largest natural gas utility, can you describe Union Gas's role in connecting natural gas exploration to the Ontario consumer?

Steve: Union Gas contracts for natural gas supply from all over North America, including Western Canada, the US Gulf Coast, and most recently from the Marcellus and Utica shale basins in Pennsylvania and Ohio. Union Gas contracts for pipeline transportation capacity on various third party pipelines to move that gas to Ontario where it then connects onto our network. Once that gas gets to Ontario and into our pipeline system, we move it either into our underground storage facilities if it's not needed at that point in time, or we transmit and distribute that gas all across Ontario to various residential, commercial, and industrial customers.

IBR: How does Union Gas decide how much to charge consumers for natural gas?

Steve: We do not make that decision. The rates that Union Gas charges customers is regulated by the Ontario Energy Board (OEB). The price of the natural gas commodity itself is unregulated in North America. When Union Gas buys natural gas for customers that we serve directly, we pass that cost on to consumers at our cost with no mark-up. Union Gas makes money based on the rates charged on the assets we use to distribute, transmit, and store natural gas, which are regulated by the OEB. The

OEB determines the overall capital

Steve Baker
President, Union Gas

Steve Baker is the President of Union Gas Limited, Spectra Energy's Ontario-based natural gas storage, transmission, and distribution holding firm with more than 100 years of experience and service to customers. He brings a wealth of financial, business development, marketing, and customer service experience to the role, a position he's held since January 2012. Steve joined Union Gas in 1989 and has held a number of executive leadership positions spanning the business. Prior to becoming President, he served as VP and treasurer of Spectra Energy Corporation.

Steve earned a BA in Honours Chartered Accountancy studies and a Master of Accounting from the University of Waterloo, and holds CPA and CMA designations. He is a member of the Institute of Chartered Accountants of Ontario, the Canadian Institute of Chartered Accountants and The Society of Management Accountants of Ontario.

About Union Gas

Union Gas Limited, a Spectra Energy company, is a major Canadian natural gas storage, transmission, and distribution company with $6.4B in assets. Serving over 1.4M residential, commercial, and industrial customers, Union Gas provides natural gas to communities across northern, southwestern, and eastern Ontario. The company owns and operates the Dawn Storage Hub in Southwestern Ontario, which is the largest integrated underground storage facility in Canada, providing an important link in the movement of natural gas across North America. Listed as one of Canada's Top Employers for 2014, the company has approximately 2,200 employees.

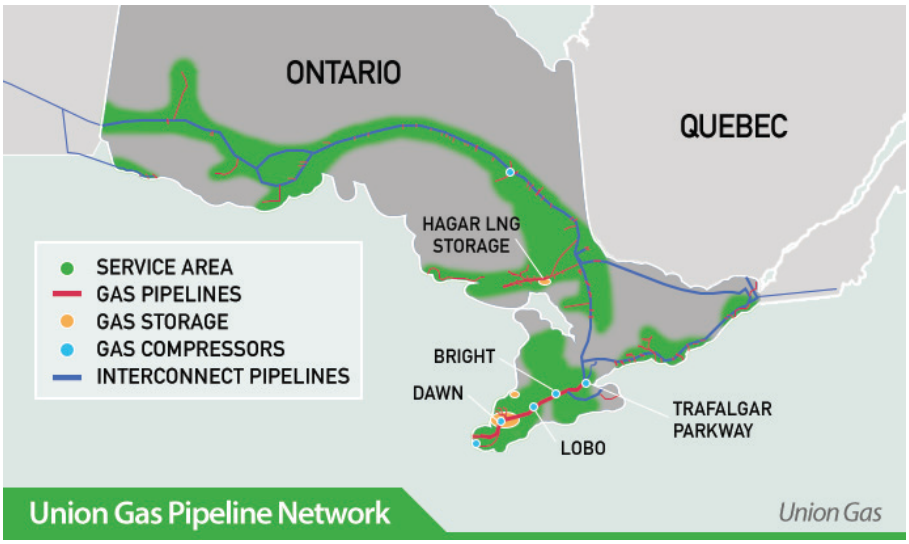
OEB determines the overall capital structure and return on equity that we can get on our assets as well as the costs we incur to provide service to customers. This is what determines what customers pay for natural gas service.

IBR: If Unions Gas's return is regulated, how does the company grow against its competitors, if they are also regulated to similar returns?

Steve: The way we grow is by developing and expanding our system where it makes economic sense. As an example, we are currently in the process of completing some major expansions on our large transmission pipeline system that extends from Sarnia to Toronto, to connect the new Marcellus and Utica shale gas to our customers. Even though our return is fixed and regulated, the way we grow our business and grow our revenues is to expand our system in order to meet customer demand for additional or new service from our company.

IBR: If I live in your service area, do I have to buy gas from you?

Steve: You do not have to buy gas from our company, as the natural gas market is unregulated. Consumers in Ontario can buy the gas commodity from Union Gas, where we pass the commodity cost through to consumers at cost with no mark-up. Alternatively, customers can also buy gas themselves, or through a third party energy marketing company. Typically, most of our large commercial and industrial customers in Ontario buy their own gas, either directly or through a marketer, while most residential customers buy gas through our company.



IBR: How does Union Gas manage the range between the winter and summer seasons?

Steve: Ontario is blessed with good geology. We have many old, depleted natural gas fields which make great underground storage facilities. Ontario actually used to produce a lot more natural gas than it does today. Once those gas fields were fully produced, we redeveloped them for natural gas storage. In the summer, when consumer gas consumption is the lowest, we take gas that comes into our system and we inject that gas underground into our storage facilities. In the winter, when demand is higher, we take that gas out of storage, put it into our pipeline system, and distribute it to customers.

Storage of natural gas is also crucial as the province moves toward renewable energy generation like wind and solar, where natural gas can act to balance the electricity supply in Ontario. Natural gas can

be taken out of storage to fuel gas fired power plants when renewable energy generation is down. Then when renewable generation is on, we can take that gas and put it back into storage. Storage serves a lot of purposes and provides significant flexibility to the province to meet overall energy demands.

IBR: Given discussion on fracking, and the dangers of pumping fluids back into the earth, is this a safe practice?

Steve: Underground natural gas storage is very safe. Union Gas has been storing natural gas this way for over 50 years. Our storage is all naturally occurring, and we're simply putting gas back where it was originally stored for millions of years. All of the storage pools we operate have a very thick and strong cap rock on the top of the reservoir. We monitor the storage wells to ensure we don't overpressure a pool and damage the reservoir, pressurizing it to a maximum of approximately 70% of historical pressure levels. That gives us the confidence that we can manage that pool and maintain integrity.

IBR: What does Union Gas do to keep its pipelines from leaking or exploding?

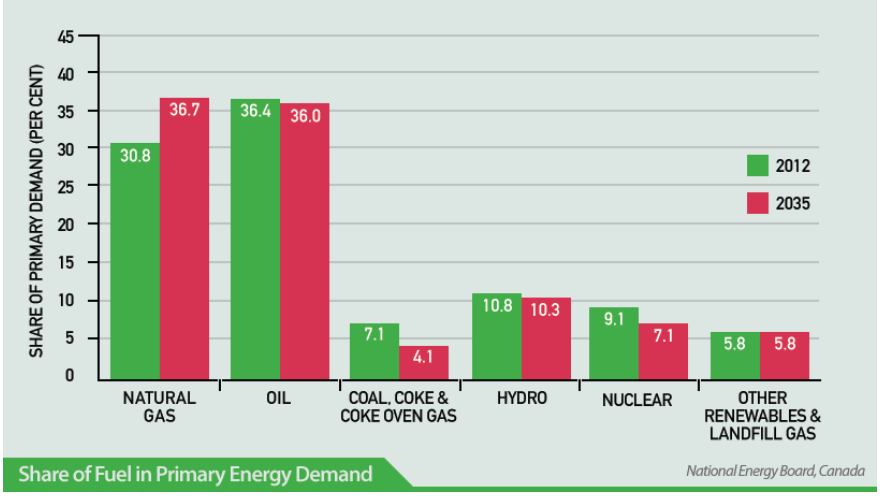
Steve: When Union Gas constructs new facilities, they meet very high standards. Our number one area of focus when we build new facilities is to meet all required codes and standards, and we often choose to go well beyond the minimum standard. Once the facilities are in the ground, we inspect those pipelines approximately every seven to eight years. Through the use of pipeline inspection tools and X-Rays, we look for damage like corrosion and pipeline thickness erosion. We also periodically dig up sections of the pipeline and visibly inspect it in order to assess the overall condition of the pipe. If we run into any issues, the pipe is repaired or replaced.

IBR: What is a typical life cycle of a natural gas pipe?

Steve: There is no single answer. The lifecycle of a pipeline really varies based on various factors, including the vintage of the pipe itself and the ground conditions in which the pipe is located. Through our pipeline integrity program, we're consistently monitoring our pipelines and we're very proactive with checking pipelines susceptible to hazardous environments. Most of the pipelines that we build will have at least a 40-50 year life cycle.

IBR: Traditionally, Union Gas has procured its supply from far away places like Western Canada and the Gulf Coast. Do you see this changing given the rise of shale gas?

Steve: As a natural gas utility, Union Gas focuses on having a diverse portfolio of gas supplies. These supplies are obtained from across North America and delivered on many different pipelines. This helps us to provide our customers with a more diverse and stable commodity price. We are very supportive of supply diversity and will continue to keep buying our supply from various locations.



IBR: Union Gas has been vocal in its opposition to the TransCanada Energy East pipeline. Given the increase in cheap supply from Pennsylvania, why would Union Gas oppose removing sections of the underutilized main line from service?

Steve: Firstly, Union Gas is not opposed to the Energy East Pipeline project. The Energy East project involves TransCanada wanting to convert about 3,000 km of its "Mainline" gas pipeline to oil service from Alberta to Ottawa. For 90% of the project, from Alberta to North Bay, that existing natural gas pipeline system is underutilized today. Union Gas is not opposed to finding better uses for underutilized pipeline capacity. Our issue is with the 300 km section from North Bay to Ottawa. That pipeline is fully utilized today and is critical for meeting the market demand in Ontario, Quebec and the US Northeast, regardless of whether the gas is sourced from Western Canada or the Marcellus. The Energy East project would have that line be converted to oil transportation with a new replacement gas line built in its place. We believe the proposed replacement natural gas pipeline is too small to meet the gas market requirements.

Further, if TransCanada has to build a new replacement pipeline as a result of converting the existing North Bay – Ottawa line from gas to oil, our view is that the higher capital cost and related capital risks relative to the existing line being converted to oil transportation should be borne by the Energy East project and its shippers, not by Eastern Canada's gas consumers. All Union Gas, Enbridge Gas Distribution and Gaz Metro are looking for is to be left cost and capacity neutral.

IBR: Do you see that your concerns are being recognized?

Steve: TransCanada has now filed its Energy East application with the National Energy Board, which is currently reviewing the application. We expect them to make a decision as to whether the application is complete sometime this spring. Assuming the application is deemed complete, the NEB would commence the hearing process where we will voice our concerns.

It should be noted that all three major gas utilities in Eastern Canada – Union Gas, Enbridge Gas Distribution in Ontario, and Gaz Métro in Quebec – have raised our concerns with TransCanada directly. Our preference is always to negotiate a settlement and reach agreement outside of the formal regulatory process. In this case, we did not reach an agreement and will be going down the regulatory path.

IBR: Has Union Gas considered signing up for capacity on one of your parent companies' pipelines to supply your Eastern Ontario Customers?

Steve: Yes. Our parent company is planning a new project to move Marcellus and Utica gas to Ontario – the pipeline is called the NEXUS Gas Transmission project. We have signed an agreement for capacity to move Marcellus and Utica gas on that pipeline to Ontario. Given the significant natural gas supplies being produced in the Marcellus and Utica shale plays, we feel that it is critical to get that supply physically connected into Ontario. The pipeline still has to go through regulatory approval process in the US, but it's clearly a project we think is good for Ontario and our consumers.

"OUR PARENT COMPANY IS PLANNING A NEW PROJECT TO MOVE MARCELLUS GAS TO ONTARIO AS PART OF THE NEXUS GAS TRANSMISSION PROJECT."

IBR: What opportunities do you see for Union Gas to grow given the relatively mature nature of the market in Ontario?

Steve: Even though the natural gas market in Ontario is mature, we continue to see a lot of opportunities to grow the company. One, there are still a lot of communities in Ontario that still don't have access to natural gas and instead use other forms of energy and we are working to connect these communities to our system. Further, we are currently going through a number of major expansions to our transmission system to expand natural gas deliveries to Toronto, Eastern Ontario, and Quebec. Additionally, with the competitive price of natural gas relative to other fuels, we believe there are opportunities in compressed natural gas (CNG) and liquefied natural gas (LNG) in the transportation sector.

IBR: Do you think there is substantial market potential for LNG in transportation and what steps need to be taken to convert those vehicles to use LNG instead of diesel?

"THE LNG MARKET FOR TRANSPORTATION FOLLOWS A CHICKEN-EGG DILEMMA."

Steve: The LNG market for transportation is currently in a bit of a chicken-egg dilemma. When we approach transportation companies to discuss the potential of converting their diesel vehicles to natural gas or to consider purchasing LNG vehicles, they ask 'where am I going to fill up?' If we build the infrastructure, we then ask the question of whether there will be enough demand to support this new infrastructure. It's a tough market to get going initially. However, the federal government has recently announced some tax incentives in the form of enhanced capital cost allowance for LNG facilities. Those incentives will apply to both LNG facilities that will be used to export natural gas from the West Coast as well as LNG facilities that help fuel the domestic transportation sector. That is a very positive step and could help overcome some of the initial inertia in terms of moving the LNG transportation sector forward.

IBR: Given Canada's aging workforce, what challenges or opportunities do you think this poses for Union Gas?

Steve: Clearly we're seeing the impact of the aging workforce, particularly if we look at our field personnel, where the average age is mid-fifties. However, I definitely think that leads to many opportunities in the sector. As an example, we are actively recruiting and training new employees, putting them side-by-side with experienced employees so they are ready to step in and replace them when they choose to retire. In addition, we are actively looking to expand our workforce by recruiting directly from colleges and universities in order to support our growth plans. Currently, we provide

opportunities for engineers to get their P. Eng designation and accountants to get their Certified Accounting designations while working at Union Gas. These new employees are the future leaders of the company and we are proactively planning for the future.

the company and we are proactively planning for the future.

IBR: Do you think we can rely on the Canadian government to help impose programs to improve energy literacy through the education system? If not, what do energy companies need to do to encourage proper discussion?

Steve: I don't think we can rely solely on government to do all that education for us. I think the government can play a role through partnering with industry and academic institutions to develop a better curriculum that can be extended into our school system at various grades. However, it will be the responsibility of the industry to facilitate that discussion. It starts by having our employees educating their kids about the energy sector and how energy is used to produce many of the products that we use and are part of our everyday lives, how energy is used and what the energy sector means for jobs and economic opportunities, I think those are all things that we should do more of.

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Nicholas Zeeb

HBA Candidate 2016

Nicholas Zeeb is an HBA Candidate 2016 and the current Editor In Chief for the Ivey Business Review. Nicholas has a passion for construction, video games, and technology. Nicholas has previous work experience in cost estimation for multi-million dollar petroleum retail projects and is interested in pursuing a career in project management.

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EPCOR will pay 100M cost for natural gas project

Written By: News Monday, September 21st 2015

Left to right. EPCOR VP Karim Kassam, EPCOR Senior V.P. Commercial Services Stephen Stanley, Arran-Elderslie Mayor Paul Eagleson, Huron Kinloss Mayor Mitch Twolan, Borden-Ladner Gervais Representative, J. Mark Rodger

Southern Bruce County finally has a plan in place to bring natural gas to the area.

Edmonton based Epcor will front all of the 100 million dollar set up cost..meaning no money from taxpayers.

Epcor will recoup the costs from consumers through the rates they will charge.

Kincardine, Huron Kinloss and Arran-Elderslie have been working for years to bring home the service to one of the last corners of the province without it.

It is hoped that Epcor will be able to secure some provincial money to help home owners with conversion costs.

Epcor's Senior Vice President Commercial Services Stephen Stanley comments.

(Click to play)

Stanley says the goal is to get the conversion cost down enough that the investment of converting will be paid back within two years.

He says Epcor will still move ahead with the project even if there is no provincial money coming.

Meetings are planned with local industry who are very keen on hooking up…..adding, they have been driving the plan.

He says the industrial section that are interested are almost enough to make the system affordable.

Kincardine Mayor Anne Eadie says in previous talks with the province, the indication they support this project has been apparent.

(Click to play)

Eadie says they have not received any kind of official word from the province regarding the project.

Kincardine Mayor Anne Eadie

Arran-elderslie Mayor Paul Eagleson says having natural gas for the local industry will be huge but its also vital for the residents…

(Click to play)

Huron Kinloss Mayor Mitch Twolan says the potential money savings will be huge for everyone…

(Click to play)

Epcor will meet with consultants on Tuesday to get the Environmental Assessment underway, a requirement for approval from the Ontario Energy Board.

They'll submit an application with the OEB within six months.

It is expected approval to proceed will be given four months after that, meaning shovels could be in the ground around the end of 2016.

Stanley says public meetings will be held in each community to explain what the construction will be, how the utility will work and how people can hook up to it. He says they will have some estimated conversion costs at that time.

Chesley will have their meeting on October 15, October 16th in Ripley and in Kincardine on October 17th.

All three mayors were smiling during the announcement and admit, it is an exciting day.

Mayor Mitch Twolan says the three communities worked for five years as a collaborative, looking at what is best for all three communities as a whole, rather than just separately.

He feels there will be strong numbers for those wanting to convert to gas pointing to surveys that were taken four years ago, when there were no estimated costs at all for the project.

He says at that time, 55 per cent of Huron Kinloss residents were interested, and 66 per cent both in Arran-Elderslie and Kincardine.

Arran-Elderslie Mayor Paul Eagleson says the project will affect Chesley mainly.

He says the gas will come from the southend of Tara to Chesley, pick up to Paisley and then onto Tiverton.

Eagleson says Turuss Canada Industry Co. Ltd., who have a facility in Chesley's industrial park, will benefit from this project.

He says the company never had much of a chance to get off the ground, because of energy costs.

He says this will cut down on those costs significantly.

Eagleson says the key to success of this operation will be the contribution from the province to help people to convert……adding that has to get passed on to a low interest loan to get people to convert.

Former Kincardine Mayor Larry Kraemer was there for the announcement today.

He was one of the original mayors to discuss bringing natural gas to the area, over five years ago.

He says at that time, he never expected it would take so long to get things moving.

(Click to play)

Kraemer says he is pleased with the announcement and looks forward to hearing more about the project.

Epcor now working on a website to provide updates on the project.

The project is expected to take three years to complete.

EPCOR ANNOUNCEMENT

EPCOR has joined three municipalities in the South Bruce region of Ontario to create a new natural gas distribution utility.

The proposed new utility will bring natural gas service to Kincardine, Huron-Kinloss, and Arran-Elderslie, located near Lake Huron and the Georgian Bay. The three municipalities, collectively known as South Bruce, selected EPCOR following a competitive process.

"We are seeing opportunities to invest in the Ontario market, and South Bruce offers a tremendous fit between EPCOR's capabilities and the needs and aspiration of the region," said Steve Stanley, Senior Vice President, Commercial Services. "EPCOR has a strong record of developing new infrastructure, and we look forward to working with the municipalities of South Bruce."

There are a number of steps to be taken before construction can begin. This includes public consultation, and regulatory approval from the Ontario Energy Board which, if granted, is not expected until early 2017.

The South Bruce communities have a combined population of 25,000 residents and a

significant commercial / industrial presence.

http://corp.epcor.com/about/Pages/about-epcor.aspx

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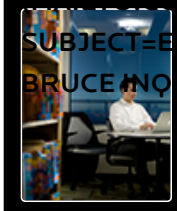
Exhibit 7
Tab 7



Filed: 2016-03-21
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COMMUNITY & ENVIRONMENTAL IMPACT

Project overiew (overview.html)

Community & environmental impact (environmental-impact.html)

Project finances (finances.html)

The regulatory process (regulatory-process.html)

We consider how we can better care for the environment in all that we do. Impacts on the Southern Bruce community will be minimized. We will work closely with stakeholders inorder to ensure this.

ENVIRONMENTAL CONSIDERATIONS

EPCOR has contracted Stantec to conduct a comprehensive environmental study (../images/project/ea-process-chart.jpg) of the construction and operation of the proposed natural gas pipelines. Stantec has more than 30 years of experience working in Ontario's natural gas industry.

The environmental study will meet the requirements of the Ontario Energy Board. We will be engaging landowners and consulting with Aboriginal communities, government agencies, and others who are interested in the project.

The environmental study and subsequent Environmental Report for the Project will be completed according to the Ontario Energy Board's (OEB) "Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (2011)."

We will look to balance development with environmental considerations like:

- Wildlife
- Trees /Vegetation
- Fish / Fish Habitat
- Soil

The study will be undertaken during the earliest phase of the project, and will then be filed as part of EPCOR's application to the Ontario Energy Board for this project.

LOCAL INFRASTRUCTURE IMPACTS

We are proposing to build a 145 km natural gas distribution network in the communities of Southern Bruce County.

Once we have consulted with stakeholders, we will prepare a definitive proposal for design and development. We will have more technical information available at that time.

EMPLOYMENT IMPACTS

We are currently in the planning stages of this project. Details on how the project will affect local employment in Southern Bruce communities will be available at a later date.

CONSULTATION

- EPCOR will engage landowners, residents, First Nations and Métis communities, as well as other interested stakeholders. This will help us understand what is most important when developing the pipeline route for this project.
- EPCOR will continue to engage stakeholders over the coming months and bring more detail on the proposed route, as well as costs for customer connections.
- After the mid-October information sessions, another round of open houses will be scheduled to share more details on the project.

Filed: 2016-03-21
EB-2016-0004
Exhibit 7
Tab 7
Page 7 of 13

PROJECT FINANCES

Project overiew (overview.html)

Community & environmental impact (environmental-impact.html)

Project finances (finances.html)

The regulatory process (regulatory-process.html)

EPCOR's Southern Bruce County Natural Gas Utility Project is expected to cost between $100 and $120 million. Some of this will be spent in the local community on materials and services, both during construction and once the distribution system is operating.

There will be no taxpayer dollars spent on construction costs associated with bringing the natural gas lines to the municipalities.

The municipalities and EPCOR are pursuing provincial support to assist customers in making the conversion to natural gas.

Thursday, February 18, 2016

Communities Stay With EPCOR

Kincardine | by John Divinski

Despite Union Gas bid, three municipalities stay committed to EPCOR.

0:49

Despite the recent announcement by Union Gas about plans to provide natural gas service in rural areas and the continuing work of EPCOR in southern Bruce County, all applications are on hold.

Kincardine Mayor Anne Eadie says the Ontario Energy Board has decided to hold what is called a generic hearing sometime in April before any further applications are heard.

The generic hearing will consider what mechanisms will be allowed to recover the costs of expanding service into rural Ontario.

Union Gas wants to charge the new users an extra $500 a year for 10-years, plus add $2 a month to existing customers bill until the debt is paid off.

The suggested cost is $88-million.

EPCOR has suggested it will foot the bill, at no cost to the taxpayer, for the construction costs that they estimate between $100-and $120-million.

Eadie says they're sticking with EPCOR because they met the criteria in the original Request for Information process and they've been working with the company ever since.

Eadie cautions though when EPCOR makes an application, it will be the OEB that makes the final decision on who the provider will be.

Since the generic hearing has been called, it will likely be late this year before the OEB entertains any specific applications from providers like Union Gas and EPCOR.

The April hearing will hear from supporters and interveners alike and any decision on the issues being raised may not come until late Fall.

Meanwhile, Union Gas has scheduled several public meetings in the region to explain their plan.

March 1st in Chesley (Community Centre), March 2nd in Lucknow (Recreation Centre) and March 3rd in Kincardine (Davidson Centre).

All three meetings will be held from 5:30 PM to 8:30 PM.

You may recall EPCOR held several public meetings last Fall to explain their plan.

Previous Page | Print This Story

Weather

WINTER **S**TOR**M** **W**ARNING **IN** **E**FFECT

-9.1°C
Most**ly** **C**loudy
Wind: ESE **15 km**/h

Cloudy with Snow-- 5 to 10cm-- with Blowing Snow, Windy

full forecast

Events

Museum Munchkins
Southampton - 1/22 to 3/11
See yourself starring in a murder mystery?
Shelburne - 3/2
Casting Call
Shelburne - 3/2
more events

Web Site by Websmart Inc

Rural Municipalities not happy with Union Gas

by Sandy Lindsay

February 29, 2016
www.kincardinetimes.com

Feature

To Comment on this article Click Here

No sooner had the municipalities of Kincardine, Huron-Kinloss and Arran-Elderslie announced that they had signed Franchise Agreements with EPCOR Utilities for the installation of natural gas to their communities, than Union Gas stepped up, and in, to announce that they are about to hold 'open houses' for the public in rural areas with a view to expanding its services.

In September, 2015, the three municipalities selected EPCOR after a six-month competitive Request for Information. EPCOR would be a new entrant into the province for providing natural gas service and, as part of their proposal said that the company would absorb costs involved in hooking up to the service.

For the company, based in Alberta, it would be its foray into the Ontario market.

Both companies, EPCOR and Union Gas, have applied to the Ontario Energy Board (OEB), which will be

According to the Manager, Murray Costello, Union Gas has been working to build support with the OEB and provincial government over the past three years to expand into rural Ontario. The service, if approved by the OEB, would go into 29 rural and First Nation communities to add to its existing customer base of 220 municipalities.

The three municipalities that recently entered into the Franchise Agreements with EPCOR however, appear to be puzzled by Union Gas' recent notice to hold open houses given that the Councils had already signed with EPCOR.

The Councils are concerned that citizens will, in fact, be confused by Union's recent activities and said that they find the company's approach to public information sessions to be irresponsible and inappropriate given the circumstances.

The three mayors of the

conducting ahearing to "... consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario Communities currently not served."

In its application to the OEB, the Union Gas proposal included having existing Union Gas Limited customers pay for a portion of the costs to connect new customers.

Both applications have been put on hold until the public has the opportunity for input into certain items, such as:

* should the OEB implement new mechanisms to encourage utilities to expand distribution service to new communities ... if so, what should they be

* should the OEB impose conditions or make changes to Municipal Franchise Agreements and Certificates of Public Convenience and Necessity to reduce barrier to natural gas expansion

* does the OEB have the authority to require ratepayers of one utility to subsidize the costs of another to expand into new communities? Under what circumstances (if any) would this be appropriate?

Written submission emails can be sent to:www.ontarioenergyboard.ca/notice

municipalities, Mayor Eadie (Kincardine), Mayor Twolan (Huron-Kinloss) and Mayor Eagleson (Arran-Elderslie), have asked that Union Gas convey in writing to those residents attending each open house, the fact that EPCOR holds the franchise rights to distribute natural gas.

To read the original announcement by the MunicipalitiesClick Here

quoting ref. # EB-2016-0004 or phone: 1-877-632-2727.

In recent correspondence from the District Manager Waterloo/Brantford Union Gas to South Bruce Councilors, the company said that they were about to host three open houses in the Bruce County region to "... inform residents that there are options available for providing service ...".

 Click the orange arrow to read the second column

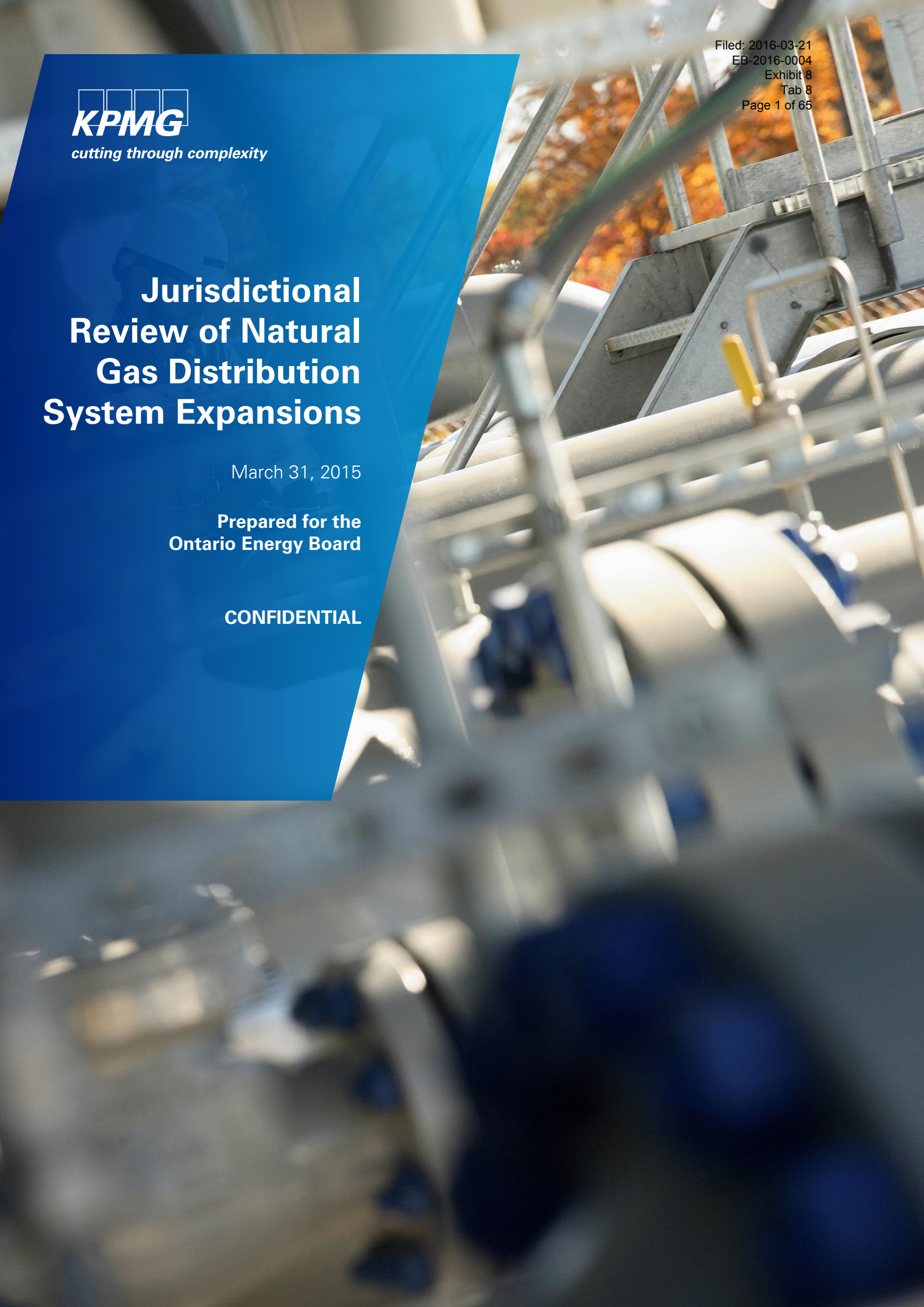
KPMG
cutting through complexity

Jurisdictional Review of Natural Gas Distribution System Expansions

March 31, 2015

Prepared for the Ontario Energy Board

CONFIDENTIAL



Contents

1 Introduction

The Ontario Energy Board ("OEB" or "Board") retained KPMG LLP ("KPMG") to provide advisory services to help the Board in determining best practices for natural gas distribution system expansion. The purpose and scope of our research entailed a review of similar and relevant jurisdictions to determine if there are lessons to be learned for rural natural gas expansion, particularly with respect to the onboarding of new franchise areas and new entrants.

1.1 Approach

The jurisdictions assessed herein were selected for further research in collaboration with the OEB following an initial jurisdictional scan encompassing nearly two dozen U.S. states and Canadian provinces. Our research focused primarily on the way regulators approve applications from new entrants, evaluate expansion projects into unfranchised territories and/ or implement other policies to accomplish similar objectives.

This report analyses in detail developments in six jurisdictions to assess the processes used in each to expand natural gas distribution systems into unserved or underserved areas:

Country	Jurisdictions
United States	Alaska
	Connecticut
	Maine
	New York
	North Carolina
Canada	New Brunswick

In undertaking this research and analysis, KPMG relied on information obtained from secondary sources, including reports, presentations, testimony, applications, orders, websites and articles by utilities, regulators, legislatures, industry associations and energy commentators. We have not independently verified the information obtained from these sources and therefore cannot confirm the accuracy of the materials presented. Given that the purpose and scope of this jurisdictional review was to examine policy and processes, we did not undertake quantitative data analysis.

In the course of our work we were able to review only a portion of the large number of materials that are available on this subject. It is possible that we have not selected the most relevant material and that there may be other findings that would be of greater interest. Additional information about developments in a selection of other jurisdictions is included as Appendix 1.

1.2 Report Structure

This report is structured as follows:

- Executive Summary, which highlights main findings.
- Case Studies, with each organized into the following 6 sections:
  - *Case Study Overview* – a one-sentence summary of the case study.
  - *The Problem* – a description of gas supply and demand in the respective jurisdiction.
  - *Proposed Solutions* – a summary of the jurisdiction's broader policy and regulatory proposals.
  - *Tools Used* – a narrower focus on policy decisions.
  - *Regulatory Issues* – a process-oriented analysis describing regulatory decision-making.

  - *Outcomes* – a description of any subsequent developments, if known.
- Observations that elaborate on the Executive Summary.
- Comparative Tables that provide an overview of the jurisdictional review.
- Appendix 1, which presents a high-level summary of relevant findings from the initial jurisdictional scan.
- Appendix 2, which presents a list of 21 discussion questions issued by the New York State Public Service Commission in advance of a technical conference it held on natural gas expansion.
- Appendix 3, which presents a list of 15 discussion questions published by the National Regulatory Research Institute on issues that utility commissions should consider on natural gas expansion.

2 Executive Summary

2.1 Context

Approximately 3.5 million homes and businesses in Ontario have access to natural gas.[1] However less than 20 percent of rural residents do.[2] Some estimates indicate that there may be 40 communities with populations greater than 500 that could be considered viable candidates for new gas distribution systems.[3] As a result, policymakers and regulators have an interest in evaluating potential strategies for expanding natural gas service.

On February 18, 2015, the Ontario Energy Board issued a letter to all applicants and potential applicants with the appropriate financial and technical expertise, giving them the opportunity to propose plans for natural gas distribution system expansion in Ontario. In the letter, the Board said it would hear applicants' requests for regulatory flexibility pertaining to proposed system expansion projects on matters such as:

- The potential use of surcharges to improve project feasibility by reducing the level of upfront capital contribution;
- The potential allowance for recovery of the revenue requirement associated with expansion costs in rates prior to the end of any incentive regulation plan term once the assets are used and useful; and,
- The potential consideration of individual projects with a "Profitability Index"[4] of less than 0.8 and/ or a portfolio of expansion projects with a PI of less than 1.0.

Prior to the Board's February 2015 letter, the Province of Ontario had indicated in its Long-Term Energy Plan and in mandate letters to related ministers a potential for government assistance in facilitating natural gas distribution system expansions.[5] These proposals included the potential creation of:

- "Natural Gas Access Loans" – totalling $200 million over 2 years to help communities partner with utilities to extend access to natural gas supplies; and,

[1] This figure includes residential, commercial and industrial consumers. *Source:* Ontario. Ministry of Energy. *Achieving Balance: Ontario's Long-Term Energy Plan*. Toronto: Ministry of Energy, 2013. Web. March 2015.

[2] The Ontario Federation of Agriculture estimates there are 500,000 rural families and 30,000 farms and small businesses in Ontario that would benefit from access to natural gas. *Sources*: Ontario Federation of Agriculture. "Turning up the Heat for Natural Gas Expansion in Rural Ontario." *News*. Ontario Federation of Agriculture, 2013. Web. March 2015; and Ontario Federation of Agriculture. "Natural Gas Infrastructure." *Issues*. Ontario Federation of Agriculture, 2015. Web. March 2015.

[3] Examples include Kincardine, Milverton, Bancroft and Marathon. *Source:* Union Gas. *Ontario's Economic Renaissance Fuelled by Natural Gas*. Union Gas, 2013. Web. March 2015.

[4] The Profitability Index ("PI") is a net present value calculation that the Ontario Energy Board uses to evaluate whether proposed natural gas distribution expansion projects will shield existing customers from the additional costs of system expansion. A PI of 1.0 indicates that over the life of the portfolio of projects, the additional customers connected to the existing system will pay the entire costs of the expansion. The PI can be evaluated through rates and/ or an upfront capital contribution. The PI test specifies that any one individual expansion project within a portfolio must meet a PI of 0.8, which is intended to prevent cross-subsidization within a portfolio. *Source:* Ontario. Ontario Energy Board. E.B.O. 188. *Final Report on Natural Gas Distribution System Expansion* and *Appendix B Guidelines*. Ontario Energy Board, 30 January 1998. Web. March 2015.

[5] Ontario. Ministry of Economic Development, Employment and Infrastructure. *Mandate Letter*. Ministry of Economic Development, Employment and Infrastructure, 25 September 2014. Web. March 2015.

- "Natural Gas Economic Development Grants" – in the amount of $30 million to help fund economic development projects.

These recent initiatives in Ontario make it a timely point to review the experiences of other jurisdictions.

2.2 Challenges of Rural Natural Gas Expansion

There are a number of reasons that could potentially explain why a region remains unserved, why a franchise area does not exist or why new entrants have refrained from entering an otherwise established gas distribution market. These reasons may include:

- Regional transmission pipeline constraints;
- Substantial upfront costs associated with fuel-switching, such as equipment replacement;
- Difficulties in accurately forecasting household conversions, such as in areas where electric baseboard heating must be replaced at high cost;
- Topographical challenges, such as rocky, mountainous, coastal or far-northern terrain;
- Unfavourable local economic conditions, including (but not limited to) low customer density, sub-median per capita income and/ or a declining population;
- Regulatory prohibitions on utility cross-subsidization through rates; and,
- Regulatory economic tests that do not provide the flexibility needed to take a long-term view or manage additions on a portfolio basis.

2.3 Key Findings

- No jurisdiction we evaluated was prepared to deviate significantly from the practice of using an economic test – based on a net present value calculation or similar metric – for determining whether a proposed expansion project should be approved.
- We did not observe an explicit preference in the jurisdictions examined for inviting new entrants, creating new service territories or using municipally-based systems to address a lack of service in rural areas.
- Decision-makers were generally not willing to broadly socialize the costs associated with extending service to areas that did not pass the economic test over the existing natural gas distribution grid and existing natural gas distribution customers.
- There was an emphasis across jurisdictions on identifying and prioritizing industrial, commercial or institutional anchor loads.
- With the exception of North Carolina, where certain refunds/ monies were made available to natural gas distributors from the upstream transportation sector, none of the jurisdictions we examined were willing to impose a surcharge or subsidy on the commodity cost of natural gas to fund system expansions.
- To facilitate expansion efforts, regulators experimented with time-limited, project-specific innovations that demonstrated flexibility with respect to a number of factors.
- With the exception of the major greenfield development in New Brunswick, we did not observe an extensive use of deferral and variance accounts to postpone the recovery of costs associated with natural gas system expansions

3 Case Studies

3.1 Alaska

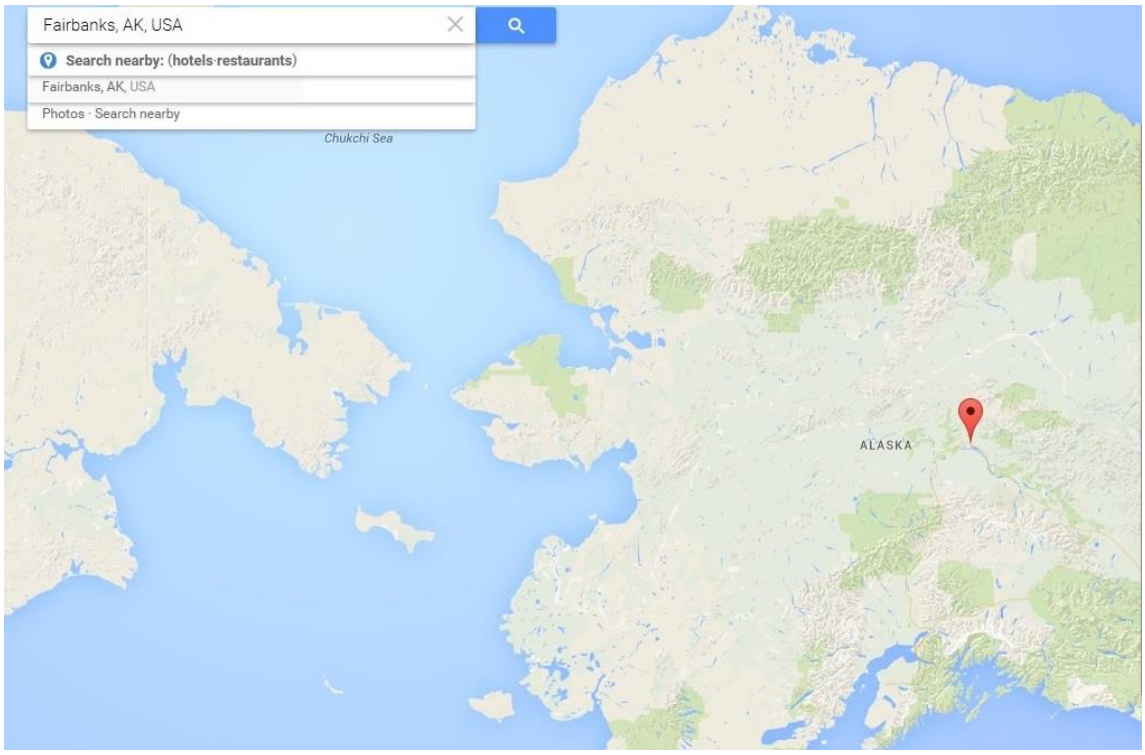
3.1.1 Case Study Overview

This case study examines Alaska's efforts to expand natural gas distribution service to remote communities in the state's interior.

3.1.2 Problem

Among U.S. states, only Texas produces more natural gas than Alaska. Yet despite this abundant local supply, many of the state's residents lack access to natural gas distribution service because the gas is used instead at well sites for oil extraction or to fuel the state's electricity generation.[6] This is a problem because Alaska's residents consume significant amounts of energy to heat their homes. Only Wyoming and Louisiana consume more energy on a per-capita basis than Alaska.[7] As a result, household energy bills are "extremely high."[8] In fact, Fairbanks – the state's second biggest city – has some of the highest residential energy costs of any city in the United States.[9]

Figure 1: Location of Fairbanks, Alaska



Source: Google

[6] U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Alaska*. U.S. Department of Energy, 19 June 2014. Web. March 2015.

[7] Ibid.

[8] The predominant energy source in Fairbanks is fuel oil. *Source:* Alaska Industrial Development and Export Authority. *Alaska Interior Energy Plan*. Alaska Industrial Development and Export Authority, 22 February 2013. Web. March 2015. Pg. 2.

[9] Alaska Industrial Development and Export Authority. *Interior Energy Project*. Alaska Industrial Development and Export Authority, 19 February 2015. Web. March 2015.

3.1.3 Proposed Solutions

In 2012, then-Governor Sean Parnell proposed the Interior Energy Plan, which is also commonly referred to as the Interior Energy Project. The Interior Energy Plan was a major proposal to lower energy bills quickly and to improve the region's air quality. As Governor Parnell described it in his 2013 State of the State Address:

> "To keep the state of our state strong, let us choose a future of affordable and abundant energy. Despite all our energy sources, energy costs remain a huge burden on Alaskans. That needs to change. That's why we developed the Interior Energy Plan, a strategy that includes low-interest loans, gas storage tax credits and cash for a moveable gas liquefaction plant and distribution system… It will slash energy costs for homes and businesses."[10]

The underlying supply components supporting the Interior Energy Plan were:

- Natural gas sourced from Alaska's North Slope, the state's vast oil- and gas-rich area along its northern, Arctic coastline;
- Gas liquefied at a new North Slope LNG plant;
- LNG trucked south to Fairbanks;
- A new regasification and storage plant in Fairbanks; and,
- Local distribution system expansion in the interior communities of Fairbanks and North Pole.

3.1.4 Tools Used

The Interior Energy Plan was implemented using two tools:

- A state financing plan; and,
- The creation of a new municipally-owned utility in the Fairbanks area.

3.1.4.1 State Financing Plan

In 2013, the Alaska State Legislature approved a comprehensive financing package for the Interior Energy Plan.[11] Financing came from a few sources:[12]

- $150 million USD in loans for expanding the local distribution system;
- $125 million USD in loans for the North Slope LNG plant;
- $57.5 million USD in grant funding "to directly reduce the cost of LNG";[13] and,
- $30 million USD in existing tax credits ($15 million USD per qualifying LNG storage tank).[14]

[10] Governor Sean Parnell. *2013 State of the State Address*. State of Alaska, 16 January 2013. Web. March 2015.

[11] Alaska. Legislature. Senate. *An Act Relating to development project financing by the Alaska Industrial Development and Export Authority…* (SB 23) 2013 Reg. Sess. (12 April 2013) *Alaska State Legislature*. Web. March 2015.

[12] These are the figures as they appeared in the Regulatory Commission of Alaska's order granting Interior Alaska Natural Gas Utility a certificate of public convenience and necessity. *Source:* Regulatory Commission of Alaska. Docket: U-13-103. *Order Denying Application of Fairbanks Natural Gas, LLC To Amend Certificate of Public Convenience and Necessity and Granting, With Condition, Application of Interior Alaska Natural Gas Utility for Certificate of Public Convenience and Necessity*. Order No. 19. (Dated and Effective 20 December 2013). Web. March 2015.

[13] AIDEA, 2013. Pg. 3.

[14] In 2010, Alaska implemented natural gas storage tax credits equal to $1.50 USD per thousand cubic feet of "working gas" storage capacity, up to the lesser of $15 million USD or 25 percent of the costs incurred to establish gas storage facility. These credits may be used to offset up to 100 percent of corporate income tax liability. *Sources:* Bill White. "Guide to Alaska natural gas projects." *Alaska Natural Gas Transportation Projects*. Office of the Federal Coordinator, 21 January 2015. Web.

Included in the legislation is an increase in the bonding authority of an existing state agency designed to finance the expansion plans and an interest rate cap of three percent charged to any project financed from the revolving fund established by the financing plan.

3.1.4.2 Creation of New Municipally-Owned Utility

In anticipation of the Interior Energy Plan's development in and around Fairbanks, two utilities applied to the Regulatory Commission of Alaska ("RCA" or "Commission") for authorization to supply natural gas service to the new service territory:

- Fairbanks Natural Gas, LLC ("FNG"), wholly owned by Pentex Alaska Natural Gas Company LLC ("Pentex"). Pentex owns three companies in Alaska involved in natural gas transportation and distribution services, but is itself headquartered in Texas and owned by a collection of investment funds headquartered in Minnesota; and,
- Interior Alaska Natural Gas Utility ("IANGU" or "IGU"), a newly formed, public corporation wholly owned by Fairbanks North Star Borough ("FNSB"). FNSB is an upper municipality (the functional equivalent of a county) that includes both the City of Fairbanks and the City of North Pole, which is on the outskirts of Fairbanks.

FNG had served the densely-populated areas of downtown Fairbanks since 1998 and, as of the time of the Interior Energy Plan, had approximately 1,100 customers. Its natural gas is sourced in the form of LNG from Cook Inlet to the south and trucked to Fairbanks where it is vaporized and distributed through FNG's distribution system. FNG expanded in 1999 and 2005, but subsequent expansion plans were delayed due to uncertainty around future LNG supplies from Cook Inlet. With the prospects of new LNG supplies sourced from Alaska's North Slope and a new regasification and storage plant in Fairbanks, FNG applied to the RCA to amend its Certificate of Public Convenience and Necessity ("CPCN" or "certificate") to expand its service territory.

Concurrent to FNG's filing, IGU was a new entrant that filed for a certificate to service the areas surrounding FNG's territory. It was formed when the two cities within FNSB (i.e., Fairbanks and North Pole) voted to transfer their utility powers to the Borough. While municipally-owned utilities are exempt from regulation in Alaska, they do need to apply to the Commission for their initial CPCN.[15]

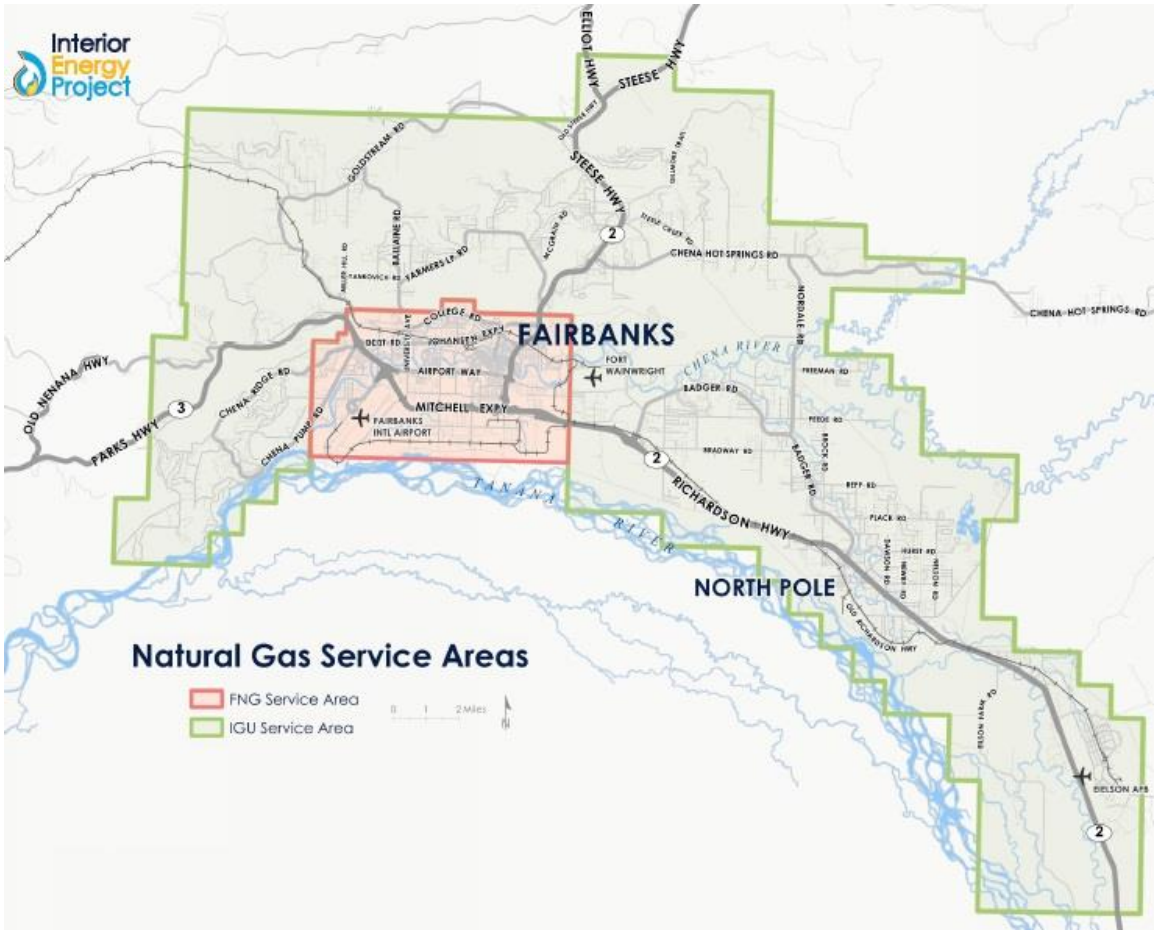
For reasons discussed in the next section, the Regulatory Commission of Alaska denied FNG's application and granted IGU the new franchise and service territory. From our own review of the applications' details, it appears that the two proposals offered comparable economics but that IGU committed to a more aggressive expansion program and could offer to finance the expansion without the need for a return on equity. The data in the application indicate:

Entity	Customers	Rate Base per Customer	Sales (MCF)	Tariff per MCF
Fairbanks Natural Gas	1,980	$26,495	3,274,089	$15.56
Interior Gas Utility	13,366	$28,535	3,448,977	$15.45

March 2015; and Alaska Department of Natural Resources. Division of Oil & Gas. "Financial Incentives and Tax Credit Programs." *Exploration Incentives.* Alaska Department of Natural Resources, 2013. Web. March 2015.

[15] Alaska Stat. § 42.05.711.: Exemptions.

Figure 2: Natural Gas Distribution Areas Territories in Fairbanks, Alaska



Source: Alaska Industrial Development and Export Authority

3.1.5 Regulatory Issues

Alaska Statute 42.05.241 sets out the requirements for when the RCA may grant a certificate. The two conditions are that:

- "The services are required for the convenience and necessity of the public;" and,
- "The applicant is fit, willing and able to provide the utility services applied for."[16]

The Commission had already found in three previous orders – dating to 1997, 2000 and 2005 – that natural gas distribution service satisfied the first condition, both in general terms and in the Fairbanks area specifically. With respect to the second condition, there is a multi-part test, which the Commission evaluated both for FNG's and IGU's applications.

The threshold requirements to demonstrate "fitness, willingness and ability," as described in the RCA's order granting IGU a certificate, are:

- Sufficient organization;
- Financial backing;
- Technical facilities and equipment, including proposals for engineering and construction of plant to be built;

[16] Alaska Stat. § 42.05.241.: Conditions of issuance.

- Operations expertise; and,
- Management and administrative experience.

The Commission found that FNG failed to demonstrate it had a viable expansion plan for the proposed new area, which resulted in its application to expand its service territory to be denied. Specifically the Commission was skeptical of FNG's ability to guarantee the industrial load that its expansion plan was based upon.

Conversely IGU had advantages in a few categories. In addition to relying on the state financial assistance as part of the Interior Energy Plan, IGU was backed by:

- The resources of the Borough;
- Its ability to raise taxes; and,
- Its ability to issue bonds.

The Commission wrote:

> "IANGU has access to intra-agency loans from the FNSB, has access to tax-exempt financing such as revenue and general obligation bonds, has income and property tax exempt status, and has the ability to qualify for state and federal loan and grant programs. IANGU presented testimony that it has an advantage over an investor-owned utility in accessing low cost debt and grant financing."[17]

In support of its application, IGU also submitted a six-year build-out plan to achieve 80 percent saturation within the franchise area by 2021, a peer-reviewed design and a commitment to reinvest any profits back into the infrastructure.

As a result, the Commission found that IGU "demonstrated sufficient levels of fitness, willingness and ability… to provide natural gas utility service in the FNSB," while FNG "failed to demonstrate a threshold level of fitness, willingness and ability sufficient for expansion of its service area."[18]

The Commission's ruling against FNG, as noted above, came down to the inadequacy of FNG's proposed expansion plan, and not because it lacked sufficient financial backing or technical expertise. The Commission explained:

> "We make no negative finding in these proceedings regarding FNG's continued fitness, willingness and ability to provide service in its existing certificated area. We note that there is a significant customer base available for FNG to expand service within its existing certificated area, and we expect FNG to do so as gas becomes available."[19]

IGU's certificate came with only one condition. Security of supply was important to the Commission, and IGU is required to maintain a five-day supply of LNG in storage – a condition that also applied to FNG's existing certificate.

3.1.6 Outcomes

IGU's application projected that it would serve:

- 1,403 customers by the end of calendar year 2017; and,

[17] Regulatory Commission of Alaska. *Order No. 19*. Pg. 24.

[18] Ibid. Pg. 27.

[19] Ibid. Pg. 19.

- 13,336 customers by the end of calendar year 2021.

However, there have been two significant developments since the creation of the Interior Alaska Natural Gas Utility:

- As of today, the supply of LNG from the North Slope is in doubt. Due to escalating costs, the private-sector contractor that would have transported LNG to Fairbanks via trucking was unable to proceed with the contract. Alaska ended its formal agreement with the partner company and is currently reviewing options, such as using the state-owned railroad to transport the gas instead.
- To speed the transition to natural gas, the State of Alaska is considering buying Fairbanks Natural Gas through its state economic development agency, the Alaska Industrial Development and Export Authority ("AIDEA"). Due diligence is underway.[20]

3.2 Connecticut

3.2.1 Case Study Overview

This case study examines Connecticut's recent policy proposals to expand natural gas distribution service to reach the state's rural communities.

3.2.2 Problem

Unlike in neighbouring Massachusetts and Rhode Island where nearly half of all households use natural gas for space heating, less than a third do so in Connecticut.[21] The state's gas infrastructure currently leaves many rural communities far from transmission and distribution mains, and even in areas where gas mains exist, approximately 216,000 residential and commercial customers[22] have not converted – despite the fact their hook-up costs would be covered by LDCs.[23] An additional 89,000 "off-main" customers would require 900 miles of new mains to reach. For these households and businesses, Connecticut's Department of Energy and Environmental Protection estimates it would cost $1.44 billion USD to provide distribution infrastructure to all of them (broken down as $512 million USD for service and meters and $926 million USD for gas main extensions). (These figures imply average costs of $16,160 per customer for the off-main group.) To add to these costs – for a state with just over 3.5 million people – an additional $1.16 billion USD would be required for residential or commercial equipment conversion.[24]

Similar to other states in New England, Connecticut has no in-state sources of natural gas, relying on interstate pipelines for supply instead. This has led to concerns about supply, especially in cold winter months, as the state has been increasing the share of natural gas used for electricity generation.[25]

[20] Dermot Cole. "State agency to purchase Fairbanks natural gas utility." *Alaska Dispatch News*, 28 January 2015. Web. March 2015.

[21] Connecticut. Department of Energy and Environmental Protection. *2013 Comprehensive Energy Strategy for Connecticut*. Department of Energy and Environmental Protection, 19 February 2013. Web. March 2015.

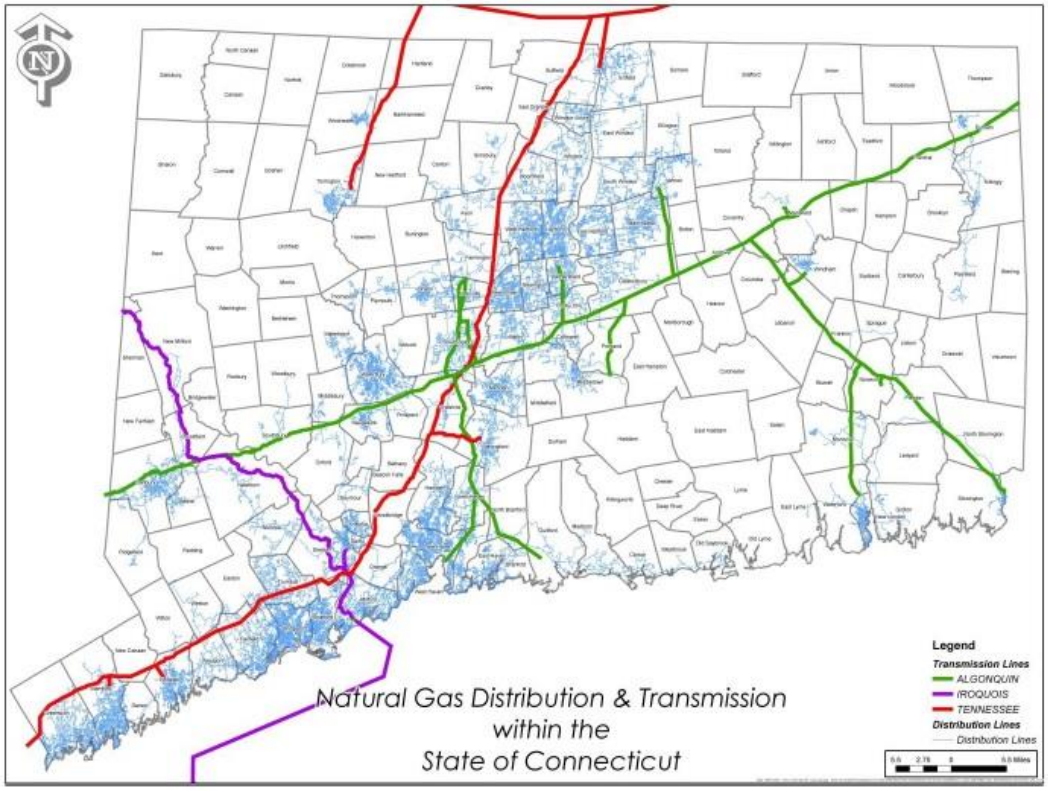
[22] Ibid.

[23] Connecticut's three gas LDCs are Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and Yankee Gas Services Company.

[24] All monetary figures attributable to the *Comprehensive Energy Strategy*. Population estimate from United States Census Bureau.

[25] U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Connecticut*. U.S. Department of Energy, 18 December 2013. Web. March 2015.

Figure 3: Connecticut's Natural Gas Infrastructure



Source: 2013 Connecticut Comprehensive Energy Strategy

3.2.3 Proposed Solutions

In 2013, Connecticut's Department of Energy and Environmental Protection ("DEEP") released the *Comprehensive Energy Strategy* ("CES" or "strategy"). While an objective analysis, this document was closely aligned with Governor Dannel P. Malloy's political commitments to lower energy bills and improve the environment. The CES was the result of a broad consultation process. A draft strategy was released months before finalization and subjected to public comment, numerous agency reviews, six technical meetings and five public hearings. As a result, the strategy's proposals can be considered "current thinking" on the natural gas policy in this state.

At over 200 pages, the detailed strategy document proposed a planning horizon out to the year 2050, with a number of changes to energy policy in the following areas:

- Energy efficiency;
- Industrial energy needs;
- Electricity supply including renewable power;
- Natural gas; and,
- Transportation.

The next section focuses on the statutory and regulatory proposal contained in the chapter on natural gas and is best summarized by the following paragraph in the *Comprehensive Energy Strategy*'s introductory chapter:

> "The Strategy further seeks to align Connecticut's energy future with the emerging opportunity provided by shale gas for a lower-cost, less-polluting and domestically available (and thus more reliable) foundation for society's energy needs. In identifying natural gas as a bridge to a truly sustainable energy future, it puts forward a seven-year game plan for expanding access to natural gas across Connecticut with

> a goal of providing nearly 300,000 [additional] Connecticut homes, businesses and other facilities with an energy choice that includes natural gas."[26]

In several places throughout the CES, it is emphasized that the state legislature, DEEP, the Public Utilities Regulatory Authority ("PURA") and other state agencies are to use the strategy's priorities and proposals to guide future decision making.

3.2.4 Tools Used

This section describes the detailed recommendations outlined in the *Comprehensive Energy Strategy*. While the CES has a planning horizon out to 2050, the natural gas expansion planning horizon was intended to take place over the seven years following the strategy's release. The most relevant policy proposals to expanding distribution services to unserved and underserved areas are[27]:

- Establish a planning process for natural gas expansion;
- Raise customer awareness of the opportunities for fuel-switching through marketing;
- Make energy efficiency investments and fuel-switching affordable through financing and incentives for choosing the most energy efficient technology;
- Enact regulatory changes to broaden the reach of financing options that utilities may provide and update Connecticut's regulatory accounting processes; and,
- Coordinate and streamline permitting and siting processes for building underground infrastructure.

3.2.4.1 Establish a planning process for natural gas expansion

The strategy recommends that Connecticut's three LDCs be required to submit annual expansion plans that track a number of elements, including:

- **Customer conversion plans and schedules** that outline which customers in their service territory are targeted that year for conversion, sub-divided into a number of categories like on-main and off-main, and residential, commercial and industrial, etc. Further, these plans should target anchor loads and assess their respective economic development potential, as well as target residential areas where customer conversion is likely to be high – such as newer developments or prior expressions of consumer interest;
- **Feasibility analysis** that includes estimated capital budgets, assessment of market conditions (e.g., gas-to-oil spread) and cost/ benefit analysis;
- **Outreach and marketing efforts** to gauge customer awareness;
- **Assessment of pipeline supply capacity** to ensure reliability;
- **Financing mechanisms** that could be leveraged to finance capital and operational expenditures;
- **Cost-reduction strategies** that demonstrate the LDCs have taken into account measures to reduce the cost of expansion (e.g., targeting whole neighbourhoods at once, dedicating specific crews for main extensions, streamlining permitting and siting, etc.); and,
- **Regulatory proposals** that the LDCs recommend for the Public Utilities Regulatory Authority's consideration, to help each LDC implement its plans.

[26] DEEP, 2013. Pg. ii.

[27] An additional set of recommendations in the CES were targeted at those Connecticut households and businesses where fuel-switching to natural gas is not considered feasible at this time, in that projected savings under current prices could not be made to cover the costs of conversion/ expansion. Those additional recommendations were primarily aimed at energy efficiency issues, such as more efficient oil and propane furnaces, solar thermal water heating, ground source heat pumps, mandating low-sulfur heating oil, among other proposals.

3.2.4.2 Raise customer awareness of the opportunities for fuel-switching through marketing

The CES estimates that a "robust marketing effort" by Connecticut's three LDCs would cost approximately $1.5 million USD to $2 million USD a year. The strategy proposes that each utility seek to increase customer awareness in its service area about the cost savings from fuel-switching, the importance of planning ahead (as opposed to waiting until a furnace must be replaced) and the ability to reduce individual household costs by aggregating fuel-switching with neighbours or a local anchor load.

3.2.4.3 Make energy efficiency investments and fuel-switching affordable through financing and incentives for choosing the most energy efficient technology

An issue common to the challenge of converting customers to natural gas is the oftentimes high upfront costs of conversions – both to extend service lines to residences and to replace existing, functioning equipment. Even if customers fully understand the benefits of natural gas and would like to convert, they may simply be unable to afford to pay these costs.

The CES puts forward several proposals to address this issue:

- Loan programs for high efficiency heating and domestic hot water systems, delivered through participating banks and credit unions and potentially with state support in the form of a subsidy;
- On-bill financing programs delivered through participating gas companies;
- For particularly high-cost conversions, the strategy calls on LDCs to include in their annual expansion plans proposals on how to offer lower interest financing[28] to specific sets of off-main consumers; and,
- Direct incentives (e.g., time-limited tax credits or program spending) to encourage off-main households or businesses to convert.

3.2.4.4 Enact regulatory changes to broaden the reach of financing options utilities may provide and update Connecticut's regulatory accounting processes

These proposals are discussed in more detail in *Section 3.4.5: Regulatory Issues* below.

3.2.4.5 Coordinate and streamline permitting and siting processes for building underground infrastructure

In 2012, legislators in Connecticut passed a law that, among other things, required municipalities and the Department of Transportation to notify the Public Utilities Regulatory Authority about pending construction projects on public highways so that PURA could in turn notify utilities of opportunities to install underground infrastructure (e.g., gas lines, water mains, sewers, etc.). The strategy calls for LDCs to seek to align their expansion projects along these corridors when possible. According to the CES, installing gas mains at the same time road construction is already underway can lead to savings of 20 percent, for example, by sharing the cost of excavation and paving.

To avoid bottlenecks in the permitting, siting and inspections of future gas expansions – which could be expected during the proposed 7-year build-out period – the strategy proposes a generic approvals process, standardizing the application process and bulk procurement where feasible.

[28] The CES does not provide more detail on this proposal, saying instead "Because there is a wide difference in conversion economics and in the assumptions created by various policy underpinnings, it is essential to evaluate expansion options in detail by sub-segment and geographic location as well as under various policy refinements." DEEP, 2013. Pg. 151.

3.2.5 Regulatory Issues

Connecticut's *Comprehensive Energy Strategy* proposes the following regulatory changes:

- Change the "hurdle rate test" to reduce the upfront customer charge for main extensions;
- Alternative rate riders to assist customers in paying for main extension costs – e.g., contributions in aid of construction ("CIAC") – over time as opposed to an upfront payment;
- Allow greater flexibility when calculating customers' main extension costs; and,
- Establish a mechanism for the timely recovery of capital expenditures made by gas companies.

3.2.5.1 Hurdle Rate Test

Similar to many jurisdictions, Connecticut uses a regulatory mechanism called "the hurdle rate test" to determine whether the costs associated with connecting new customers will be sufficiently covered by the expected future increases in revenue from adding those additional customers. The purpose of this calculation is to ensure gas companies pursue customers that will be cost effective. As of the 2013 strategy, the "payback period" used by PURA to calculate the hurdle rate test ranged from 15 years for one LDC to 20 years for the other two. The CES proposed to extend the payback period to 25 years for all three LDCs, noting that one LDC in Massachusetts is even permitted to use 33 years for residential customers. According to DEEP estimates, this one regulatory adjustment (from 15 years to 25 years) could reduce off-main consumers' CIACs by 40 percent. Similarly, commercial and industrial consumers would see substantial benefits.

3.2.5.2 Alternative Rate Riders

One of the most significant costs of conversion for residents that live far from distribution mains is the upfront contribution in aid of construction. Implementing these charges is also time-consuming and carries a cost for LDCs to administer, as CIACs must be calculated for each individual residence. As an alternative to this approach, the strategy recommends that PURA consider spreading these costs over time by "setting rates generically for customers that require a CIAC payment based on similar characteristics such as usage and distance from the main."[29] In this way, similar customers would be pooled together, with CIAC costs potentially spread among a larger group. The CES does not go into detail about how this might be made to work, except to acknowledge that it might require PURA to revise or rescind previous orders.

3.2.5.3 Greater Flexibility Calculating Customers' Main Extension Costs

LDCs in Connecticut are currently permitted to include revenue projections in hurdle rate tests only if there is a firm customer commitment to convert to natural gas. This makes project planning unnecessarily complex, as a project's profitability must be recalculated whenever additional customers sign up or previously committed customers fall through. The strategy recommends providing LDCs with the flexibility to make reasonable projections about future customer conversions and include these revenues in their hurdle rate calculations. As this flexibility would entail a greater element of risk, the effect of this change could be monitored over time and adjusted. The also CES recommends moving toward a portfolio view that allows LDCs to group projects together.

3.2.5.4 Mechanism for Timely Recovery of Capital Expenditures

The CES proposes using a new mechanism for LDCs to recover costs associated with gas main extensions in a timely way without proceeding to a full rate hearing, though there is not much detail in the strategy's text as to what this would entail. Instead, the Public Utilities Regulatory Authority is simply asked to study it further.

[29] DEEP, 2013. Pg. 152.

3.2.6 Outcomes

Subsequent to the release of the *Comprehensive Energy Plan*, Connecticut's three gas LDCs submitted to PURA a joint, detailed expansion plan.[30]

While Connecticut may achieve its goal of providing half the state's residences (and three quarters of commercial and industrial customers) access to natural gas, the other half of the state is, unfortunately, considered to provide "unlikely prospects for conversion," with locations too remote to ever recoup costs from energy bill savings under current assumptions and projections.[31]

3.3 Maine

3.3.1 Case Study Overview

This case study examines Maine's efforts to expand natural gas distribution service to unserved communities in the state's interior Kennebec Valley region and along the Atlantic Coast.

3.3.2 Problem

Very few Maine households have access to natural gas. The population is predominantly rural, and Maine has the lowest population density of any state on the U.S. East Coast. Among U.S. states, Maine ranks 49 out of 50 with respect to the number of homes using natural gas for space heating, with only one out of every twenty residences using it.[32] Instead the vast majority of households – 80 percent – use fuel oil.[33]

Maine is supply constrained and entirely dependent on imports via pipelines from New Hampshire and Canada. Extremely cold winters can cause shortages and price uncertainty. Most of Maine's natural gas consumption goes toward electricity generation and forestry-related industry.[34]

3.3.3 Proposed Solutions

In 2012, the Maine State Legislature passed *An Act to Expand the Availability of Natural Gas to Citizens of Maine*, which authorized state bond financing for gas distribution investments. Under this legislation, the Finance Authority of Maine is permitted to issue bonds for gas distribution expansion projects so long as the applicant contributes 25 percent of the expected total project cost.[35]

In 2013, Governor Paul LePage identified natural gas distribution system expansion as a priority in the annual State of the State Address, committing to "fast-tracked permitting… for all natural gas infrastructure," projecting yearly savings of $800 USD per household.[36]

[30] Connecticut Public Utilities Regulatory Authority. Docket Number: 13-06-02. *Connecticut's Gas LDCs Joint Natural Gas Infrastructure Expansion Plan*. Public Utilities Regulatory Authority, 14 June 2013. Web. March 2015.

[31] DEEP, 2013.

[32] U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Maine*. U.S. Department of Energy, 18 December 2013. Web. March 2015.

[33] Lori Valigra. "Will natural gas alleviate Maine's energy woes?" *Mainebiz*, 2 September 2013. Web. March 2015.

[34] U.S. EIA, 2013.

[35] Maine. Legislature. *An Act to Expand the Availability of Natural Gas to Maine Residents*. (LD 1644) 2012 Reg. Sess. (29 March 2012). *Maine State Legislature*. Web. March 2015.

[36] Governor Paul LePage. *2013 State of the State Address*. State of Maine, 5 February 2013. Web. March 2015.

Additionally, Maine law and regulatory precedent allow for a greater degree of utility competition than our research found in other jurisdictions. Specifically:

- A utility that has been previously authorized to provide natural gas service in Maine *does not* need to obtain further regulatory approval to expand into another area – so long as that other area is currently unserved. Maine's Revised Statutes 35-A §2104 reads: "…a gas utility authorized to furnish service and serving customers within the State is not required to obtain the approval of the commission to serve in any municipality in which no other gas utility is furnishing similar service…";[37] and,
- Maine's Public Utilities Commission ("MPUC" or "Commission") has "a longstanding policy in favor of gas utility competition and does not grant exclusive gas franchise territories." Even if a community *is* served by an existing LDC, the regulator can grant authorization as a second utility under Maine's Revised Statutes 35-A §2105.[38]

3.3.4 Tools Used

Natural gas distribution system expansion to unserved areas in Maine has been accomplished recently through the approval – and subsequent expansion – of a new entrant, Summit Natural Gas of Maine ("SNG" or "Summit"). SNG is a subsidiary of Summit Utilities, Inc., a privately-held natural gas transmission and distribution company that operates subsidiaries in Maine, Missouri and Colorado. The company describes its business strategy as "to aggressively seek opportunities to provide natural gas transmission and distribution in areas where natural gas is underutilized."[39]

In June 2012, SNG applied to the MPUC for unconditional approval to provide natural gas services. SNG's proposal was to build transmission and distribution lines servicing 17 communities[40] in central Maine's Kennebec Valley, which includes the state capital of Augusta. A handful of industrial facilities – mainly paper mills and a farm – would act as anchor loads, and gas would be supplied via the Maritimes & Northeast Pipeline. Two transmission lines of 12.9 miles and 52.2 miles were proposed as the backbone for local distribution mains and service lines throughout the valley.

The key elements of SNG's plan were:

- A $350 million USD investment to create a network to service 15,000 customers during an initial period;
- A 10-year rate plan – with annual reviews and (if necessary) modifications capped at 4 percent of last year's tariff recovery – that includes an adjustment for return on equity that is below a five-year running average rate;
- A rate of return on equity that is below utility industry standards for the initial years in the tariff plan;
- Rates that include an allowance for the utility to fund construction when a new customer is more than the standard distance from the existing pipeline network;
- "Second utility" status to allow SNG to serve alongside an incumbent utility in Augusta; and,
- An opportunity to fund pipeline expansion and customer conversion rebates using Tax Incentive Financing.

[37] Maine Revised Statutes, 35-A §2104: Commission approval for gas companies to furnish service.

[38] Summit Natural Gas of Maine, Inc. *Response to Towns of Cumberland, Falmouth and Yarmouth: Natural Gas Pipeline and Utility Service Request for Proposals*. SNG, 25 January 2013. Web. March 2015. Pg. 15.

[39] State of Maine Public Utilities Commission. Docket No. 2012-258. *Petition for Authority to Furnish Service as a Gas Utility*. SNG, 1 June 2012. Web. March 2015.

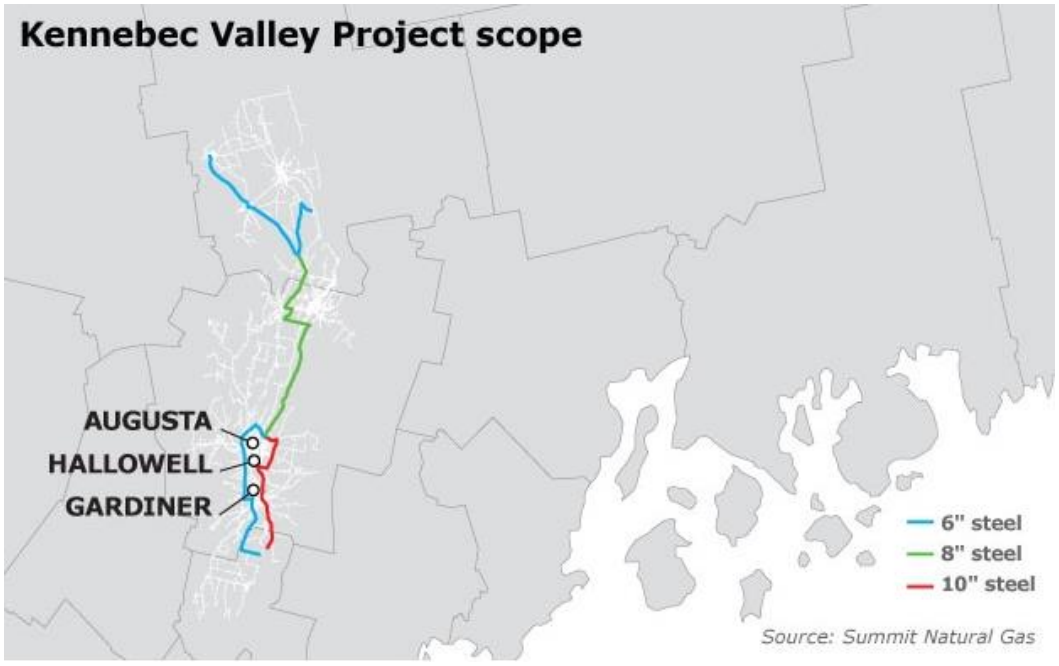
[40]SNG's service area would comprise: Richmond, Farmingdale, Gardiner, Hallowell, Augusta, Sidney, Belgrade, Waterville, Oakland, Fairfield, Norridgewock, Madison, Skowhegan, China, Albion, Windsor and Winslow.

SNG estimated its Kennebec Valley project would cost a total $350 million USD, with $240 million USD in the first four years to service 15,000 customers across the 17 communities.[41] The initial funding amount represents a cost of $16,000 per customer for the initial 15,000 customers cited. Total potential customers in the Kennebec Valley were estimated to be as high as 52,000.

Figure 4: Location of Maine's Kennebec Valley

Source: Google

Figure 5: Summit Natural Gas's Kennebec Valley Project



Source: Summit Natural Gas

[41] Summit Natural Gas of Maine. *Presentation: Kennebec Valley Expansion*. SNG, 9 October 2013. Web. March 2015.

3.3.5 Regulatory Issues

In Maine, new applicants must demonstrate the following requirements to obtain authorization to supply natural gas:

- A public need for the service;
- The technical ability to provide the service;
- Adequate financial resources to complete the proposed project; and,
- The ability to provide the service at just and reasonable rates.

Maine has a relatively low bar for demonstrating public need for natural gas utility service – essentially if service is not already provided in a given area then public need is presumed. The other three issues require more substantiation.

Demonstrating SNG's technical ability was straightforward. By the time of expanding into Maine, Summit Utilities had already completed 20 similar projects in Colorado and Missouri over the prior 15 years, serving nearly 35,000 residential, commercial and industrial customers.

With respect to financial resources, the Commission described its economic test as follows:

> "A finding of financial capability for purposes of awarding conditional authority is a threshold determination, not a conclusion based on a detailed project and rate analysis. A threshold finding helps assure the public that the entity proposing to become a public utility has a reasonable chance of bringing its project to fruition, but not that it is certain to do so."[42]

The Commission further explained that:

> "Because the entities and projects presented to us vary, so do our threshold findings, as each case is somewhat unique. We look for characteristics such as adequate business sophistication lending an understanding of how to obtain adequate funding for the project it proposes to build, as well as a high level assessment of the resources it has garnered to date for that endeavor."[43]

As a newly-formed subsidiary, Summit Natural Gas of Maine did not have audited financials available for the Commission's review. Instead the MPUC took into consideration the fitness of SNG's parent company, Summit Utilities, which was wholly owned by the JP Morgan Infrastructure Investment Fund. At the time, the Fund held more than $3 billion USD of equity investments. In a subsequent stipulation filed before the granting of unconditional authority, SNG also presented many details about its financial protections with information relating to its dividend payout ratio, level of equity capitalization, separation of credit facilities from affiliates, money pool arrangements, credit approval requirements and treatment of books and records.

With respect to rates, SNG presented to the MPUC a proposed 10-year rate plan. SNG credits its pricing model as a key to expansion because it includes, in effect, an on-bill loan that helps to bridge the gap between upfront costs of conversion and the subsequent annual bill savings from gas as a cheaper fuel source:

> "SNG has a very different pricing model that enables expansion to serve customers. By including the cost of expansion – the [contribution in aid of construction] charges

[42] State of Maine Public Utilities Commission. Docket No. 2012-258. *Order Granting Conditional Authority and Denying Motion to Dismiss.* MPUC, 17 October 2012. Web. March 2015. Pg. 6.

[43] Ibid.

> – within our rates, we are able to expand to serve customers without having those customers pay separately for construction of lines to serve them. Moreover, our rates include a generous allowance – actual cash rebates – to help customers pay for the cost of converting to natural gas. Our model is unique, but it is the basis for our high penetration rates. Other utilities may have lower rates, but their rates do not permit expansion. A low rate is of no value to customers who cannot obtain gas service. SNG's rate structure is geared toward getting lines built to serve customers. With respect to commercial customers, SNG does not provide conversion rebates."[44]

The Commission found that SNG's proposed rate plan was similar to ones it had approved previously and contained the right balance of ratepayer and shareholder protections. It is worth noting the MPUC did observe:

> "Although SNG Maine's average distribution rates for all classes are higher than rates currently charged by other Maine gas utilities, SNG Maine will offer a lower cost alternative compared to other fuels, most notably heating oil and propane. In addition, SNG Maine will provide up-front financial incentives to customers to help defray the costs to convert to natural gas."[45]

The Commission acknowledged that flexibility was necessary to facilitate expansion:

> "We observe that where, as here, the utility is seeking customers who are in no sense 'captives' of the utility – since virtually all can satisfy their energy needs using other fuels but will reduce their energy costs by adding natural gas as a resource – it makes little sense to apply all the traditional metrics for establishing that rates are 'just and reasonable.' Thus in this case we conclude that we can approve a rate plan for SNG Maine that would likely, for a genuinely 'monopoly' provider, result in rates that would either qualify as excessive or insufficiently compensatory relative to costs. We will, of course, be vigilant to ensure that customers who take service from SNG Maine are informed of the rate plan and the manner in which rates under the plan can change. As time progresses, alternative equipment ages (and even becomes inoperative) and customers become more dependent and limited in their energy options, the more traditional attributes of monopoly regulation may become more appropriate."[46]

In January 2013, the MPUC granted unconditional authority to SNG Maine to supply natural gas utility service to 17 municipalities in the Kennebec Valley.

3.3.6 Outcomes

Development has been slower than SNG projected. Since 2013, Summit has delivered natural gas distribution service to only 3,000 customers in 12 communities.[47] These customers are split between the Kennebec Valley Project and a second expansion project on the coast, which SNG announced shortly after it received approval to supply natural gas in Maine from the MPUC. [48]

[44] SNG, 25 January 2013. Pg. 23.

[45] State of Maine Public Utilities Commission. Docket No. 2012-258. *Order Approving Stipulation*. MPUC, 29 January 2013. Web. March 2015. Pg. 11.

[46] Ibid. Pg. 12.

[47] Summit Natural Gas of Maine. *Summit Natural Gas of Maine Announces 2015 Construction Plan*. PR Newswire. SNG, 25 February 2015. Web. March 2015.

[48] Tux Turkel. "For Summit Natural Gas, the path hasn't been easy." *Portland Press Herald*. 19 March 2015. Web. March 2015.

In March 2013, SNG won a competitive bidding process held by the Maine coastal communities of Cumberland, Falmouth and Yarmouth, which are located just north of Maine's most populous city, Portland. The three Portland suburbs issued a Request for Proposals to design, construct and operate a local distribution system in the three communities. Two of Maine's utilities submitted bids – Maine Natural Gas and Summit Natural Gas of Maine – while a third, Unitil, declined to submit a bid, choosing instead to focus on its existing areas.

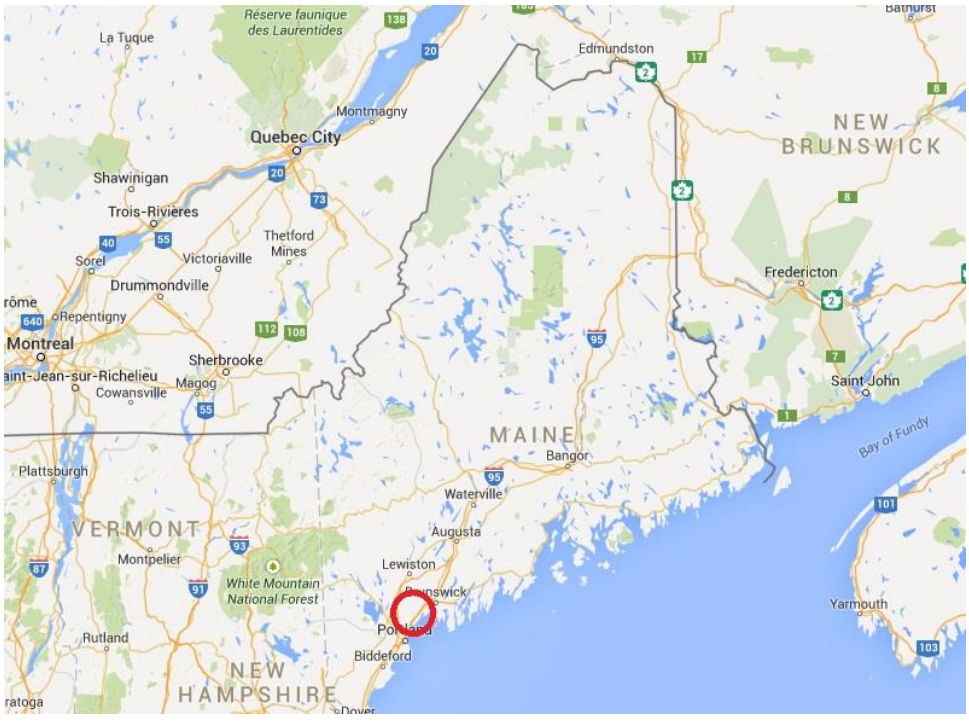
Evaluation criteria were evenly split between three items[49]:

- Saturation plan;
- Pricing structure, capacity, schedule and related considerations; and,
- Previous experience in similar communities, with marketing/ saturation, safety, customer service, reliability, pricing, public outreach and similar concerns.

The communities cited SNG's "experience, saturation commitment and pricing" as the reason for its selection.[50] SNG proposed to invest $72.5 million USD to provide local distribution service, targeting nearly 8,000 customers over five years.[51] This investment was in addition to its Kennebec Valley Project. On a per customer basis, projected costs are just over $9,000 per customer, somewhat less than for the initial expansion noted above.

Currently, Summit's 2015 construction plans aim to lay mainline pipes to 10,000 homes and businesses in both central Maine and the coast.

Figure 6: Location of Cumberland, Falmouth and Yarmouth, Maine



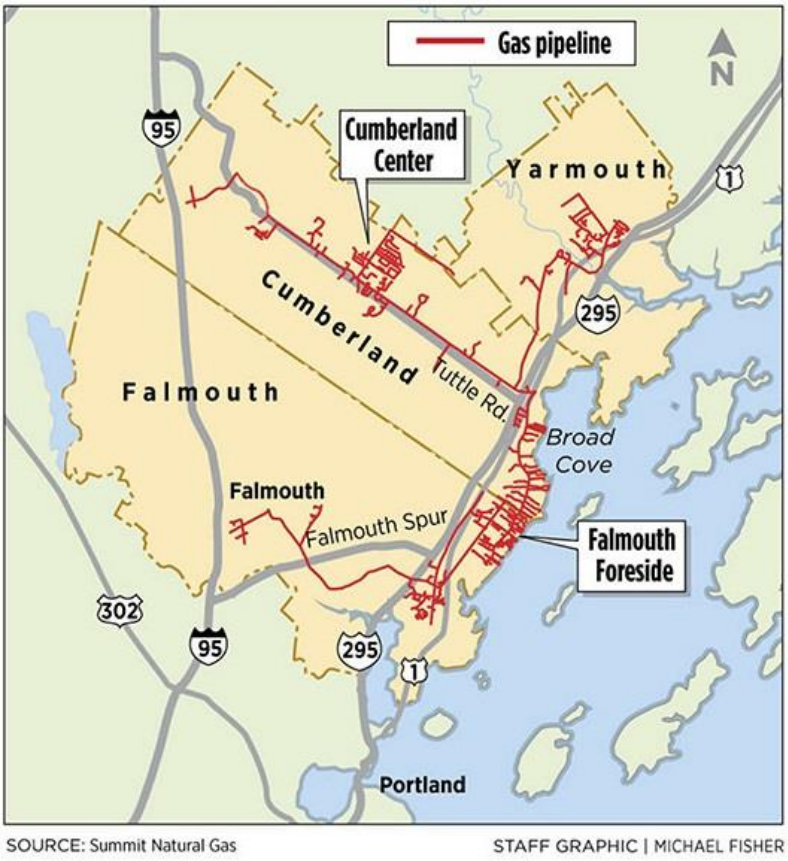
Source: Google

[49] Maine. Town of Cumberland. Item 12-177. "Request for Proposals: Natural Gas Distribution Pipeline & Utility Service." *Towns of Cumberland, Falmouth and Yarmouth.* Town of Cumberland, 12 October 2012. Web. March 2015.

[50] Maine. Town of Falmouth. "Information." *Natural Gas Project. FalmouthMe.org*. Web. March 2015.

[51] Maine. Town of Falmouth. *Natural Gas Distribution Expansion Project Update*. Falmouth, December 2013. Web. March 2015.

Figure 7: Cumberland, Falmouth, Yarmouth Expansion Project



Source: Summit Natural Gas and *The Portland Press Herald*

3.4 New York

3.4.1 Case Study Overview

This case study examines New York's efforts to expand natural gas distribution service to upstate communities, with an example of a recent expansion.

3.4.2 The Problem

More than half of New York residences use gas for space heating, yet there are still well over one million households within existing service territories with no access to natural gas. This figure breaks down to approximately 550,000 residences within 100 feet from an existing gas main and 580,000 beyond that distance.[52] Furthermore, despite New York's high saturation rate, there are still unfranchised territories considered too expensive to expand into due to remote, rocky or mountainous terrain.

Instead of ample in-state production, New York has been primarily supplied with natural gas from major pipelines extending from the U.S. Gulf Coast and Canada, with interstate pipelines extending beyond into New England.[53] More recently, significant shale production in Pennsylvania has led to

[52] U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: New York*. U.S. Department of Energy, 18 December 2013. Web. March 2015; and New York State Public Service Commission. Case 12-G-0297. "Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service." *Order Instituting Proceeding and Establishing Further Procedures*. New York Public Service Commission, 30 November 2012. Web. March 2015.

[53] U.S. Energy Information Agency, 2013.

additional pipeline capacity from both existing infrastructure and planned expansions. New York, too, has major shale gas deposits. However the state became the first in the U.S. to officially ban hydraulic fracturing in December 2014, though a temporary ban had been in place for 6 years prior.[54]

3.4.3 Proposed Solutions

On November 15, 2012, New York released a 116-page, long-term energy strategy entitled *The New York Energy Highway Blueprint* ("Blueprint").[55] The Blueprint was officially issued by the Governor's New York Energy Highway Task Force and based on a comprehensive consultation process. The Blueprint's 13 action items predominantly related to electricity policy (e.g., renewable power generation, smart grid technologies, retiring old power plants, etc.), but natural gas was also included.

The most relevant recommendation to natural gas distribution expansion was an action item labelled "Accelerate investments in natural gas distribution to reduce costs to consumers and promote reliability, safety, and emission reductions." According to the Blueprint, New York's gas LDCs have been investing significantly in utility infrastructure -- $5 billion USD in natural gas infrastructure over the prior five years and projected to invest another $5 billion USD in the subsequent five years, covering both equipment replacement and system expansion to accommodate load growth.[56]

Coming out of the Blueprint was the direction to further examine natural gas expansion policies. This task was assigned to the New York State Public Service Commission ("PSC" or "Commission"). In response, the Commission instituted a proceeding to examine existing state policies, which included a technical conference that took place on January 9, 2013 with 13 presentations from LDCs.

The 16-page order instituting this proceeding provides considerable insight into the Commission's thinking and priorities. The order highlights that over one million people heat with fuels other than natural gas, despite the fact that New York already has 19 regulated gas utilities and considerable existing gas infrastructure.[57]

Echoing the Blueprint, the Commission lays out the environmental, economic and household benefits of switching to natural gas and goes into more detail about the types of specific regulatory issues it is interested in examining further. In particular, the Commission points out that while current statutory and regulatory requirements related to natural gas expansion policy permit some flexibility, "only rarely, however, have utilities sought to employ such flexibility."[58]

In advance of the technical conference, the PSC published a lengthy and detailed list of discussion questions indicating the topics it was interested in exploring. Among the issues to be considered at the technical conference:

- Barriers to Extension and Expansion of Natural Gas Facilities;
- Rate and Ratepayer Considerations;
- Economic Development;
- Public/ Private Partnerships;
- Environmental Impact; and,

[54] Thomas Kaplan. "Citing Health Risks, Cuomo Bans Fracking in New York State." *New York Times*, 17 December 2014. Web. March 2015.

[55] New York. New York Energy Highway Task Force. *New York Energy Highway Blueprint*. New York Energy Highway Task Force, 15 November 2012.

[56] Ibid. Pg. 55.

[57] For a complete list of the natural gas utilities regulated by the New York State Public Service Commission, please visit: http://www.dps.ny.gov/

[58] New York State Public Service Commission, 2012. Pg. 7.

- Planning.

The full list of questions is attached as Appendix 2.

3.4.4 Tools Used

Even though the Commission held the technical conference on the topic of natural gas expansion policy – and posted the 13 LDC presentations[59] to its Department of Public Service website – the PSC did not issue a summary report with recommendations to policymakers, which it had initially set out to do.[60] Instead, the Commission decided it was more appropriate to deal with the specifics of natural gas expansion policy during future rate cases, applications for certificates of public convenience and necessity, etc. As a result, the next section of this case study will describe the process used by the Commission in advance of one of its orders granting a certificate to a utility to expand into a new service territory.

Last year, New York State Electric & Gas Corporation ("NYSEG") was granted an amended certificate to exercise a new franchise, expanding into a neighbouring unserved territory far upstate. The Commission's decision to deviate from established expansion policies to provide more flexibility around the expansion project's development period, as well as to require more attention to informing potential new customers of expansion, is illustrative. Specifically, the PSC adopted a ten-year development period for the expansion of gas service, as opposed to the established development period of five years.

3.4.5 Regulatory Issues

In New York, gas utility expansions or new entrants require both a franchise agreement with the locality it seeks to service and a certificate of public convenience and necessity authorizing franchise rights, as prescribed in Public Service Law Section 68:

> "In making such a determination, the commission shall consider the economic feasibility of the corporation, the corporation's ability to finance improvements of a gas plant or electric plant, render safe, adequate and reliable service, and provide just and reasonable rates, and whether issuance of a certificate is in the public interest."[61]

The Public Service Commission interprets these requirements to mean that expansion projects must be economic for ratepayers[62] in order to be afforded normal rate treatment, and its policy for

[59] New York State Public Service Commission. Case 12-G-0297. *Natural Gas Expansion – Presentations from the Jan. 9, 2013 Technical Conference*. New York Public Service Commission, 2013. Web. March 2015.

[60] The order instituting the proceeding had said, "Upon completion of the Technical Conference, Staff will provide a report to the Commission along with any recommendations it may develop" (page 9). Similarly, the Blueprint listed as an initiative, "By the end of 2012, [Department of Public Service] to issue notice on natural gas expansion policies" (page 57).

[61] NY Pub Serv L § 68 (2012): Certificate of public convenience and necessity.

[62] New York State Public Service Commission. Case 12-G-0499. "Petition of New York State Electric & Gas Corporation to Amend its Certificate of Public Convenience and Necessity and to Exercise a Gas Franchise in the Town of Plattsburgh, Clinton County, New York." *Order Amending Certificate of Public Convenience and Necessity and Requiring System Improvements*. New York Public Service Commission, 29 July 2014. Web. March 2015. Pg. 12-13.

determining whether expansion projects would unfairly burden existing ratepayers has been in place since 1989.[63] The key elements of that policy include[64]:

- Assessment of franchise proposal over a five-year development period;
- The requirement to earn the utility's Commission-permitted rate of return in the new franchise area by the end of the five-year development period;
- The ability of the utility to levy a surcharge on all customers in the new franchise area during the five-year development period, if the rate of return at the end of that period is projected to be less than the utility's Commission-permitted rate of return; and,
- If the utility levies a surcharge it must be limited solely to what is needed to recover the estimated shortfall that would exist at the end of the five-year development period.

The rate of return test is applied to profitability at the end of the development period as an annual calculation. With respect to revenue deficiency, the expected deficiency (*ex ante*) is collected through a surcharge, which may be the same as the contribution in aid of construction surcharge. It is expected to compensate the utility for the losses in the early years. For broader rate-making purposes (involving the utility as a whole), the revenues from the surcharge are excluded from revenue deficiency estimates. As long as the expansion proceeds as projected, the utility would be kept whole. There is a possibility that the actual deficiency (*ex post*) is different from the *ex ante* level – for example, if expansion was slower than anticipated or costs were higher. In that case, there is a possibility that the actual deficiency will be larger than anticipated. It is not clear from the 1989 policy statement whether the utility is at risk or if the surcharge could be continued beyond the development period to keep the utility whole.

3.4.5.1 New York State Electric & Gas Corporation Expansion

NYSEG provides electricity and natural gas services to customers across New England, including 40 percent of upstate New York.[65] In 2012 it proposed its largest distribution system expansion project in 15 years[66] by seeking to expand its natural gas franchise in the far north-eastern part of the state to include a municipal-wide franchise[67] in the Town of Plattsburgh, a rural, agricultural and sparsely-populated area it had long bordered since the time it started providing service to the neighbouring community of City of Plattsburgh.

[63] New York State Public Service Commission. Case 89-G-078. *Policy for Rate Treatment of Gas Service Expansion into New Franchise Areas*. New York Public Service Commission, 11 December 1989. Web. March 2015.

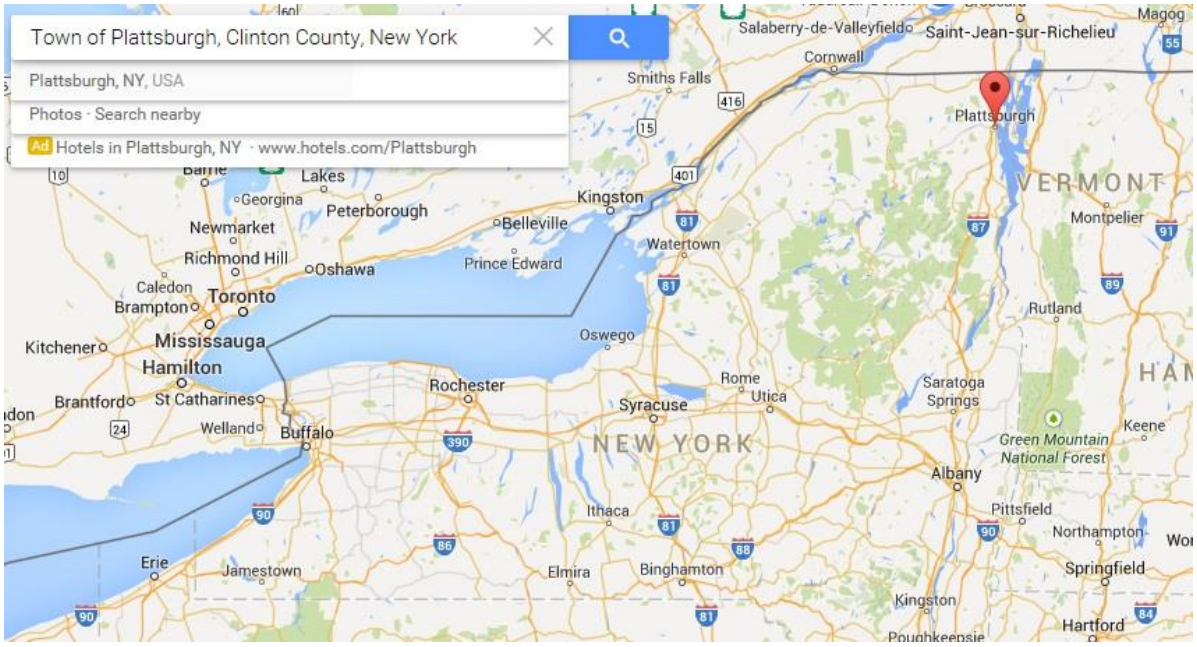
[64] Paraphrased using the original policy statement (1989) and subsequent Commission descriptions in orders from 2012 and 2014.

[65] New York State Electric & Gas Corporation. "Our Company: Service Area." *NYSEG.com*. NYSEG, 2015. Web. March 2015.

[66] Staci DaSilva. "NYSEG Announces Major Gas Line Expansion In Plattsburgh." *My Champlain Valley*, 22 October 2014. Web. March 2015.

[67] NYSEG had distributed gas to some of the Town's residences along major roadways bordering the City of Plattsburgh but did not have a franchise to distribute to the rural areas.

Figure 8: Location of Town of Plattsburgh, New York



Source: Google

NYSEG's application for a new franchise area was broadly supported by the Town, the local chamber of commerce and the economic development corporation. As part of its petition, NYSEG asked for expedited approval to service an anchor customer (Nova Bus), which the Commission quickly granted for its potential economic benefits and the company's agreement to the required surcharges. With a potential new customer base of 1,200 and initial surveys indicating nearly three-quarters of respondents saying they would convert, the PSC's approval for the rest of the application appeared straightforward.

However the proceeding lasted from November 2012 to July 2014 due to a lengthy back-and-forth between NYSEG and the Commission's staff around feasibility studies, models and build-out plans and multiple iterations thereof. A breakthrough occurred when NYSEG submitted, at the Commission's request, a ten-year development period (twice as long as the one envisioned by the Commission's 1989 policy statement). The significance of the longer development period is that it is the period of time over which rate surcharges can be collected. As a result, the longer development period "significantly reduced estimated monthly CIAC surcharges to customers."[68] After Commission staff further modified build-out plans in consultation with Town of Plattsburgh officials, a workable solution was agreed upon.

The Commission found that a ten-year development period was justified in light of:

- Current natural gas prices;
- Population density of potential customers; and,
- Significant reductions in monthly CIAC surcharge bill impacts.[69]

Taken together, these elements balanced the need to meet the utility's Commission-permitted rate of return by the end of the development period while still resulting in rates competitive enough that

[68] New York State Public Service Commission, 2014. Pg. 7.

[69] The surcharge rate ($0.282 per therm) equates to $300 a year for the average residential customer. Even accounting for this amount, customers could save $1,400 annually compared oil or $2,200 annually compared to propane. *Source:* New York State Public Service Commission, 2014, and DaSilva, 2014.

would encourage fuel-switching. In the Commission's conclusion to the order, it explained that the benefits of this approach included:

> "…the economic benefits of increased development in Plattsburgh due to the construction of this project and the expected continued availability of gas as a lower cost heating fuel. Increasing the availability of natural gas to the community may also have the added benefit of business attraction, retention, and expansion."[70]

Similar to North Carolina's focus on tracking interest from potential customers, the New York Public Service Commission required NYSEG to keep a record of any potential customer's interest in receiving gas service. The Commission explicitly laid out the types of required information: [71]

- The date a customer inquired;
- Their address;
- What documents NYSEG provided to the customer, if any; and,
- How the inquiry or request was finally resolved.

3.4.6 Outcomes

By 2017, 70 percent of residents in the Town of Plattsburgh are expected to have access to natural gas.[72]

At the time of this writing, Leatherstocking Gas Company – a new entrant looking to service communities in northern Pennsylvania and southern New York – filed for a new franchise with the Public Service Commission.[73]

3.5 North Carolina

3.5.1 Case Study Overview

This case study examines North Carolina's efforts to expand natural gas distribution service to a significant portion of the state over the past 25 years.

3.5.2 Problem

In 1989, North Carolina began a state-wide push to expand natural gas distribution service. At the time, the North Carolina Utilities Commission ("NCUC" or "Commission") had identified 38 counties out of 100 with no gas service or only minimal service availability. 20 of those 38 counties were located in unfranchised territories of the state.[74]

[70] Ibid. Pg. 34.

[71] New York Public Service Commission, 2014, page 31.

[72] DaSilva, 2014.

[73] Leatherstocking Gas Company, LLC. Case numbers 15-G-0098 and 15-G-0099 *Verified Petition*. Public Service Commission, 20 February 2015. Web. March 2015.

[74] North Carolina Utilities Commission. "Analysis and Summary of Expansion Plans of North Carolina Natural Gas Utilities and the Status of Natural Gas Service in North Carolina." *Report of the Public Staff North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations*. NCUC, 24 April 2012. Web. March 2015.

3.5.3 Proposed Solutions

North Carolina enacted 3 key pieces of legislation to promote the expansion of natural gas distribution service:

- *The Natural Gas Planning Act, 1989*;[75]
- *The Natural Gas Expansion/ Cost Act, 1991*;[76]
- *The Clean Water and Natural Gas Critical Needs Bond Act, 1998*.[77]

3.5.3.1 *The Natural Gas Planning Act, 1989*

North Carolina has four private-sector LDCs and eight municipal gas systems.[78] *The Natural Gas Planning Act* requires each LDC to file biennial reports with the NCUC on the status of expansion projects within their respective franchise territories. The legislation was later amended to apply only to LDCs with unserved areas within their franchised service territories.

Upon receiving the LDCs' reports, the NCUC compiles and summarizes the information and submits it to legislative committees. LDCs are required to report on the following items:

- Inquiries for natural gas service received from potential large users;
- The status of expansion projects previously reported to the Commission; and,
- Plans for potential expansion projects.

As an example, most recently the largest LDC in North Carolina – Piedmont Natural Gas Company – stated it had received 97 inquiries from large commercial and industrial customers about potential gas service:[79]

- 11 were successful (new customers were added as a result of those inquiries);
- 12 were progressing;
- 32 were unsuccessful or not feasible (did not provide gas to the customer); and,
- 42 were still pending (either waiting for data, being evaluated, or halted progress).

[75] *That Natural Gas Planning Act* is the short title for the bill. *Source:* North Carolina. Legislature. House. *An Act to Require Natural Gas Local Distribution Companies to Report Plans for Providing Natural Gas Service in Unserved Areas to the Utilities Commission and to Require the Utilities Commission to Report on Expansion of Natural Gas Service to the Joint Legislative Utility Review Committee.* (HB 970) 1989 Session. (31 March 1989) *General Assembly of North Carolina*. Web. March 2015. *Note:* This law was later amended to require reporting to the Joint Legislative Commission on Governmental Operations.

[76] *The Natural Gas Expansion/ Cost Act* is the short title for the bill. *Source:* North Carolina. Legislature. House. *An Act to Facilitate the Construction of Facilities In and the Extension of Natural Gas Service To Unserved Areas and To Revise the Procedures for Gas Cost Adjustments for Natural Gas Local Distribution Companies.* (HB 1039) 1991 Session. (8 July 1991) *General Assembly of North Carolina*. Web. March 2015.

[77] *The Clean Water and Natural Gas Critical Needs Bond Act* is the short title for the bill. *Source:* North Carolina. Legislature. House. *An Act to Authorize the Issuance of General Obligation Bonds of the State, Subject to a Vote of the Qualified Voters of the State, to Address Statewide Critical Infrastructure Needs by Providing Funds (1) For Grants and Loans to Local Government Units for Water Supply Systems, Wastewater Collection Systems, Wastewater Treatment Works, and Water Conservation and Water Reuse Projects and (2) For Grants, Loans, or Other Financing to Public or Private Entities for Construction of Natural Gas Facilities*. (SB 1354) 1997 Session. (9 September 1998) *General Assembly of North Carolina*. Web. March 2015.

[78] The four private-sector LDCs are Piedmont Natural Gas Company, Inc.; Public Service Company of North Carolina, Inc., doing business as PSNC Energy; Frontier Natural Gas Company, LLC; and Toccoa Natural Gas. The eight municipal systems are Greenville, Rocky Mount, Wilson, Shelby, Bessemer City, Lexington, Monroe, and Kings Mountain. Piedmont and PSNC Energy cover the vast majority of North Carolina's territory.

[79] North Carolina Utilities Commission. "The Status and Expansion of Natural Gas Service within the State." *Report of the North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations*. NCUC, 28 April 2014. Web. March 2015.

3.5.3.2 *The Natural Gas Expansion/ Cost Act, 1991*

The initial expansion reports filed under *The Natural Gas Planning Act* indicated that "the extension of natural gas service in some areas of the State may not be economically feasible with traditional funding methods."[80] In response, state lawmakers passed *The Natural Gas Expansion/ Cost Act*, which authorized "the creation of an expansion fund for each natural gas local distribution company to be administered under the North Carolina Utilities Commission."[81]

This Act enables the Commission, following a hearing, to order LDCs to create "a special natural gas expansion fund" to be supervised and administered by the Commission. The legislation implementing the expansion fund included two specific and one non-specific funding sources:

- Expansion surcharges applied to the bills of all customers of the local distribution company;
- Refunds received – from gas and transportation service suppliers – by local distribution companies as a result of decisions made by the Federal Energy Regulatory Commission, the federal government's regulatory body in the United States (comparable to the National Energy Board); and,
- Other funding sources approved by the North Carolina Utilities Commission.

However despite these three options, only supplier refunds and the interest associated with those refunds have been used so far. Changes to U.S. federal legislation and regulation in the years since *The Natural Gas Expansion/ Cost Act* may limit its applicability today.[82]

3.5.3.3 *The Clean Water and Natural Gas Critical Needs Bond Act,1998*

By 1998, the North Carolina General Assembly found that "While the 1991 legislation has been successful in providing some natural gas service to previously unserved areas of the State, that legislation has not been sufficient to facilitate the extension of service that is necessary and in the public interest, and there are still counties with no gas service or virtually no gas service."[83]

The Clean Water and Natural Gas Critical Needs Bond Act authorized the issuance of $200 million USD in North Carolina State general obligation bonds "to provide grants, loans, or other financing to natural gas local distribution companies, persons seeking natural gas distribution franchises, State or local government agencies, or other entities for construction of natural gas facilities."[84] Section 5 of the Act outlined what the funding could be used for, including (but not limited to) the costs of:

- Pipelines;
- Compressors;
- Interests in real property; and,
- Related equipment for the delivery of natural gas.

3.5.4 Tools Used

All three pieces of legislation noted above have been used. Overall, nearly $510 million USD has been invested to expand the availability of natural gas to North Carolina's unserved and underserved

[80] Quoted from the preamble of *The Natural Gas Expansion/ Cost Act, 1991*.

[81] Ibid.

[82] In the context of the legislation, "suppliers" meant interstate natural gas pipelines and equivalent entities that were subject to rate regulation. The North Carolina legislation predates the implementation of subsequent reforms (e.g., 1992 Energy Policy Act). Today most gas is either sold under market-based rate authority or in a newer rate-making environment where refunds occur far less frequently.

[83] Quoted from *The Clean Water and Natural Gas Critical Needs Bond Act, 1998*.

[84] Ibid. Section 2(b).

areas. Of this total amount, $200 million USD was provided by natural gas bonds and $115 million USD by LDC expansion funds.[85] The remaining $195 million USD was provided primarily by LDC investors. Frequent and detailed biennial reports showed lawmakers and regulators where state, LDC and investor funds were being spent on expansion projects.

3.5.5 Regulatory Issues

The North Carolina Utilities Commission administers the use of expansion funds and natural gas bonds according to the same criteria. Both sources of funding are prescribed by their respective legislation to be used only for the "infeasible portion" of an expansion project. If at any time the proposed project becomes feasible, the Commission may require the expansion funds or bond funding to be returned. The economically infeasible portion of a project is defined as:

> "In determining economic feasibility, the Commission shall employ the net present value method of analysis on a project specific basis. Only those projects with a negative net present value shall be determined to be economically infeasible for the company to construct."[86]

In calculating the net present value, the Commission uses a discount rate approximating the utility cost of capital. Additionally, in determining whether funds can be used, the Commission is required to consider:

- The scope of a proposed project, including the number of unserved counties and the number of anticipated customers that would be served; and,
- The total cost of the project.

3.5.6 Outcomes

Despite North Carolina's relatively southern U.S. geography, which suggests that heating loads are not large, the expansion of its natural gas distribution system over the past 25 years has been a priority for policymakers. As of 2014, 96 out of 100 counties in North Carolina are being served by a gas LDC. The remaining 4 counties without an LDC franchise servicing them are all located in North Carolina's mountainous west. Even there, one LDC is currently exploring ways to expand.[87]

Since 1991, $114.6 million USD of expansion funds have been used by three LDCs.[88] The table below provides a brief description of what these projects looked like.

[85] NCUC, 2012 and 2014.

[86] Quoted from *The Natural Gas Expansion/ Cost Act, 1991*.

[87] Frontier is "exploring ways to cost effectively expand into Allegheny County to serve the town of Sparta." NCUC, 2014. Pg. 2.

[88] Note that a former LDC – the North Carolina Natural Gas Corporation ("NCNG") – was acquired by Piedmont.

Figure 9: Projects Funded By the Use of Expansion Funds[89]

Project	LDC	Expansion Funds/ Total Project Cost (USD)	Project Details	Customers Served
Alexander County Project	PSNC	$4.3M/ $6.2M	Completed February 2000. Included the installation of 24.9 miles of 6-inch steel transmission main.	23 residential 53 commercial 2 industrial
Bertie and Martin Counties Project	NCNG	$10.3M/ $12.6M	Completed December 1999. Included 39 miles of 12-inch transmission main.	122 residential 93 commercial
Columbus County Project	NCNG	$3.4M/ $5.6M	Completed June 2002. Included 21.2 miles of 6-inch transmission main.	54 residential 39 commercial 4 industrial
Haywood County Project	PSNC	$4.1M/ $7.2M	Completed January 1998. Included 7.6 miles of 6-inch transmission main.	303 residential 306 commercial 11 industrial
Mount Olive to Jacksonville Project	NCNG	$16.6M/ $24.0M	Completed September 1999. Included 58 miles of transmission pipeline.	997 residential 308 commercial 13 industrial (including military installations)
Madison, Jackson and Swain Counties Project	PSNC	$28.4M/ $31.4M	Three phases, completed in 2001, 2002 and 2004.	167 residential 210 commercial 10 industrial
McDowell County Project	PSNC	$7.8M/ $13.7M	Completed December 1998. Included 22.2 miles of transmission pipeline and 22.8 miles of distribution main.	205 residential 195 commercial 8 industrial
Mayland Project	Piedmont	$38.5M/ $41.4M	Completed September 2001.	558 residential 402 commercial 11 industrial
Franklin County Project	PSNC	$1.1M/ $3.7M	Completed December 2006. Included 4.4 miles of high-pressure distribution main.	1,299 residential 210 commercial 9 industrial

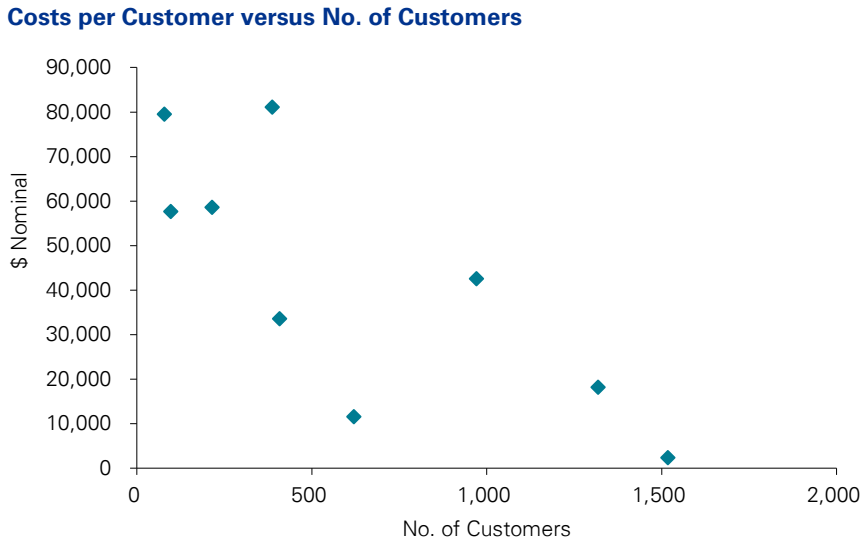
[89] Table compiled using data from 2012 NCUC biennial report.

The Exhibit below shows costs per customer served for each of the projects. Costs are divided into both those covered by the expansion fund and those covered by traditional funding. The data show that there was a wide range of costs per customer for the projects funded. Some of the differences will reflect the timing of implementation, since the data cover the period 1998 to 2006. Hence, costs will be influenced by inflation over the period. However, these differences should be small relative to the overall differences observed.

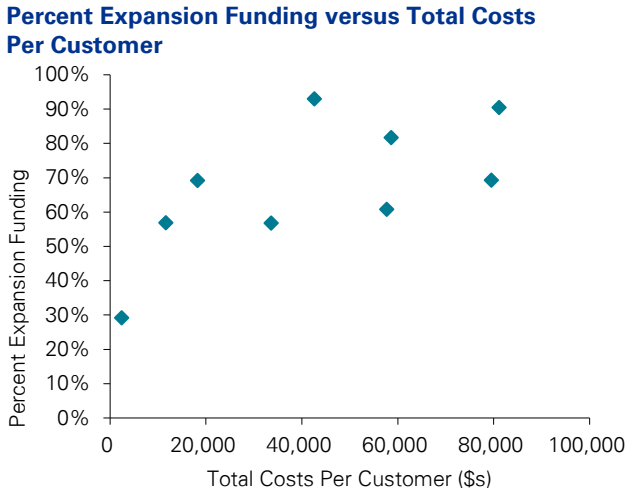
Total Cost Per Customer Connection ($s)

	Expansion Fund	Traditional Funding	Total	% Expansion
Alexander	55,100	24,400	79,500	69%
Bertie and Martin	47,900	10,700	58,600	82%
Columbus	35,100	22,700	57,700	61%
Haywood	6,600	5,000	11,600	57%
Mount Olive	12,600	5,600	18,200	69%
Madison	73,400	7,800	81,100	91%
McDowell	19,100	14,500	33,600	57%
Mayland	39,600	3,000	42,600	93%
Franklin	700	1,700	2,400	29%
Combined	**20,400**	**5,600**	**26,000**	**78%**

The graph below plots costs per customer against the number of customers for the projects. This graphic shows that projects with more customers tend to have lower costs per customer, although there is a wide dispersion in the points observed.



The graph below shows, for each project, the percentage of total costs covered by expansion funds, versus the total costs per customer. This graph shows that, as might be expected, higher per capita project costs have been associated with a higher proportion of expansion funding.



By 2005, all $200 million USD in natural gas bonds had been spent on 3 projects. However one of those projects – the Piedmont EasternNC Project – accounted for $188.3 million USD in bond funds. At a total project cost of $205.7 million USD, this also represented the largest expansion project in state history. It serves approximately 5,000 residential, 1,500 commercial and 10 institutional or industrial customers. (These figures imply a cost of about $31,600 per customer.)

3.6 New Brunswick

3.6.1 Case Study Overview

This case study examines New Brunswick's efforts to stimulate construction of a new province-wide natural gas distribution system, where none had previously been in place.

3.6.2 The Problem

In 1999, the development of the Sable Island natural gas fields off the coast of Nova Scotia made widespread natural gas distribution in New Brunswick a realistic possibility for the first time. The subsequent construction of a pipeline from Nova Scotia to Massachusetts – the Maritimes and Northeast Pipeline ("M&NP") – would traverse New Brunswick, presenting the opportunity to build lateral transmission lines to communities deep into the province, including the Northeast and Northwest. The province began to revise its natural gas policy formally in 1998 and solicited bidders to distribute natural gas and amended its *Gas Distribution Act* in 1999. The MN&P pipeline became operational in 2000.

At that time, New Brunswick had no existing gas distribution facilities and half of the province's approximately 756,600 people lived in rural areas.[90] Residential, commercial and industrial energy use was a mix of electricity, wood and refined petroleum. Diversifying energy supply was a policy priority of New Brunswick's provincial government, as the local economy was and is dependent on a large, energy-intensive and resource-based manufacturing sector.[91] Natural gas presented the

[90] Very limited local production and distribution in Moncton had ceased operations in 1991. *Source:* New Brunswick. Legislative Assembly. Select Committee on Energy. "Introduction." *First Report of the Select Committee on Energy: Natural Gas for New Brunswick*. Legislative Assembly, November 1998. Web. March 2015.

[91] New Brunswick. Natural Resources and Energy. Energy Policy Working Group. "White Paper." *New Brunswick Energy Policy*. Natural Resources and Energy, 2000. Web. March 2015.

opportunity for a more efficient, cleaner-burning and competitively-priced fuel source. Policymakers emphasized the potential of natural gas to fuel electricity generation. Environmental benefits were important, too, since the burning of oil, diesel and coal in industrial activity and power generation had reduced air quality in the province.[92]

The primary problem facing the province was not *whether* to expand gas distribution services into unserved areas but *how* to expand. Building a new province-wide natural gas distribution system, where none had previously been in place, would require a substantial upfront investment and considerable risk with respect to customer adoption. A government white paper on energy policy in 2000 highlighted:

> "In New Brunswick, a challenge exists for development of natural gas infrastructure in that potential loads required to economically justify pipeline construction are concentrated in only a few locations. The population in the province is relatively low (756,600), with 52% living in rural areas. Approximately 1/3 of the population live in close proximity to the mainline and Saint John lateral."[93]

To address these challenges, government and regulatory decision-makers had to decide the length of time a new entrant should be permitted favourable treatment to compete for new customers, achieve profitability and transition to being regulated under a traditional cost-of-service regime.

Figure 10: Energy Use in New Brunswick – Percentage Breakdown By End-Use Sector, 1998

Energy Use in New Brunswick, 1998[94]

Fuel Source	Residential	Commercial	Industrial
Electricity	43	50	35
Wood	27	3	36
Refined Petroleum	30	47	29
Subtotal	100	100	100

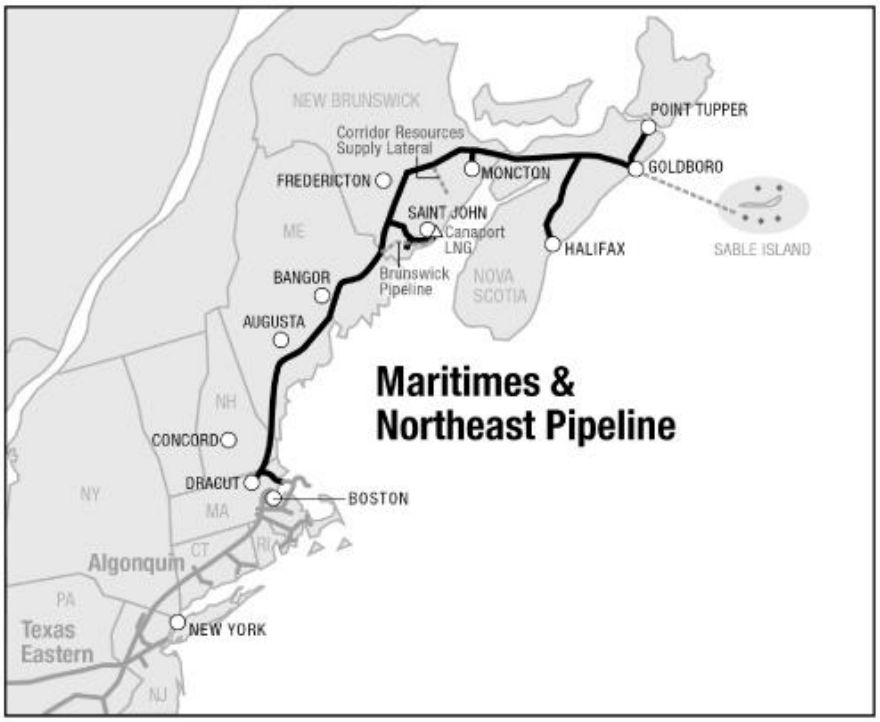
Source: Select Committee on Energy, Natural Gas for New Brunswick

[92] Select Committee on Energy, 1998. "Environmental Benefits of Natural Gas."

[93] Natural Resources and Energy, 2000. Pg. 34.

[94] Select Committee, 1998. "Energy Use in New Brunswick."

Figure 11: Location of Sable Island and Maritimes & Northeast Pipeline



Source: U.S. Securities and Exchange Commission

3.6.3 Proposed Solutions

To develop, on a greenfield basis, a completely new natural gas distribution system with service across the province required a number of policy decisions and initiatives. The Legislative Assembly of New Brunswick appointed a Select Committee on Energy ("Select Committee") that held a broad consultation, including a set of public hearings. In its final report, the Select Committee proposed, among other things, that:

- The provincial government should proceed to a formal Request For Proposals ("RFP") process to solicit bidders for a new gas distribution franchise;
- Province-wide access to natural gas distribution services should be a key criterion in evaluating proposals;
- The government should evaluate bidders' overall business plans and their ability to finance the business over the long term;
- The provincial government should avoid a broad policy of subsidies and incentives, with two exceptions:
  - The provincial government should "aggressively seek" financial support from the federal government to extend gas availability in the province; and,
  - The provincial government should provide a contribution in aid of construction to enable lateral construction into Northeastern and Northwestern New Brunswick if markets in those areas were inadequate to meet economic threshold tests; and
- All consumption of natural gas in the province should be regulated under a broad definition of gas distribution and be under provincial jurisdiction.

With respect to the necessity to regulate natural gas in the province, the Select Committee advised:

> "The committee recommends the [Public Utilities Board[95] ("Board")] be given flexibility in the methods it uses to determine a distribution company's charges to consumers. The Board should also have authority over such matters as revenue cycle services, supplier of last resort, load balancing, and the possible use of incentives in regulation."[96]

3.6.4 Tools Used

The Gas Distribution Act, 1999 separated gas distribution (i.e., the local distribution system) from gas sales (i.e., marketers). This separation was intended to promote competition in the retail market for the natural gas commodity and to limit "undue influence on the market" by a single distribution utility.[97] Policymakers had decided that a single general franchise agreement, rather than the use of multiple franchises, to serve all of New Brunswick would best accomplish the objective of uniform distribution rates and customer penetration by reducing "cherry picking" for distribution territories in densely-populated areas.[98] To promote lateral expansions from the MN&P, legislation allowed for the awarding of single end use franchises. These franchises were to be awarded by the Board and intended solely for a single industrial facility.[99] The province also retained the right to award local producer franchises for specific geographical areas involved in producing natural gas in New Brunswick.[100]

In 1999, Enbridge Gas New Brunswick ("EGNB") won the Province's RFP to develop, design, construct, finance, operate, manage and maintain the proposed province-wide natural gas utility. EGNB was awarded a general franchise to service the entire province until 2020. Its initial projections were to serve 70,000 customers in 23 communities by the end of its franchise agreement.

On June 23, 2000, the Board issued its decision on EGNB's application for approval of its rates and tariffs.[101] The Board used a number of tools to provide EGNB with flexibility to expand into New Brunswick, and each of these topics are discussed in more detail in the next section:

- Streamlined regulatory processes;
- Regulatory flexibility during the initial development period, including with respect to its length of time;
- A market-based approach to rates;
- Rate riders during the development period;
- Postponement of cost of service studies; and,

[95] Also referred to at the time as the Board of Commissioners of Public Utilities and is now the New Brunswick Energy and Utilities Board.

[96] Select Committee, 1998. "Executive Summary."

[97] Ibid.

[98] Natural Resources and Energy, 2000. Pg. 32-34.

[99] Single use franchises were subsequently only granted to large industrial companies in the Saint John area. *Source:* Enbridge Gas New Brunswick. "Independent Natural Gas Distribution Systems: In New Brunswick" *About Us.* (Corporate Website). EGNB, 2014. Web. March 2015.

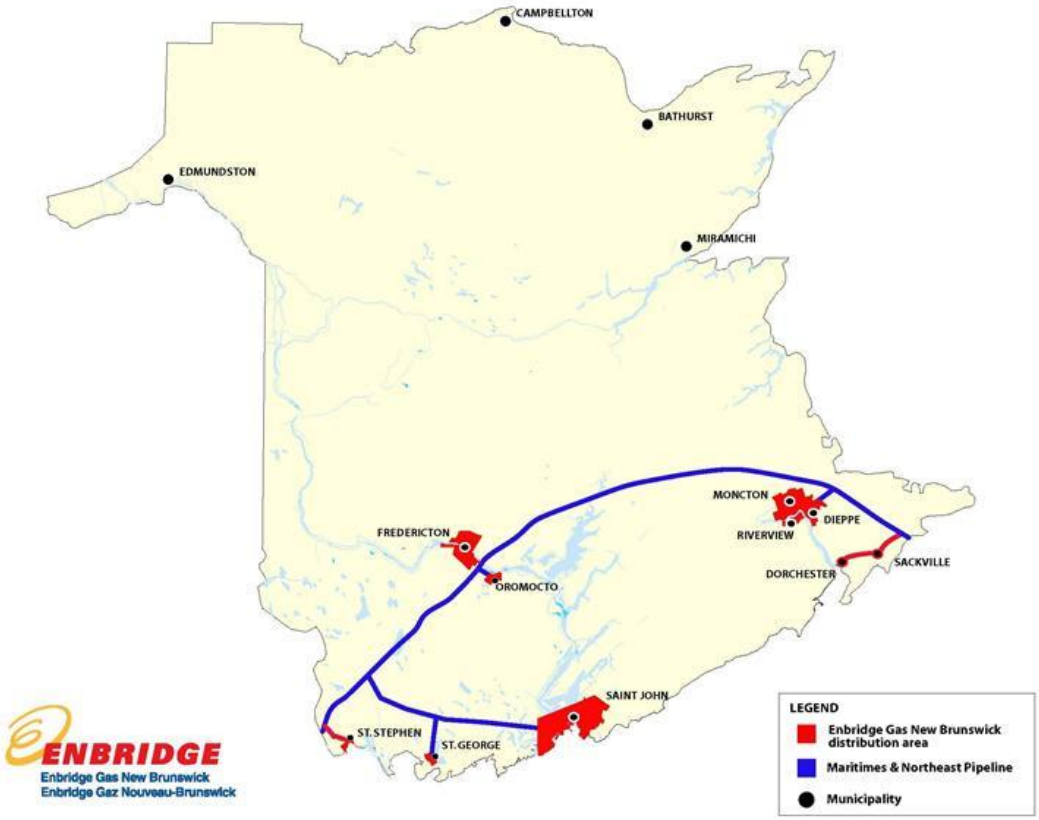
[100] Today, Potash Corporation of Saskatchewan Inc., located in Sussex, New Brunswick, is listed on the New Brunswick Energy and Utilities Board website as the sole Local Gas Producer Franchise Holder.

[101] New Brunswick. Board of Commissioners of Public Utilities. "In the Matter of an Application by Enbridge Gas New Brunswick Inc. for Approval of its Rates and Tariffs." *Decision.* Board of Commissioners of Public Utilities, 23 June 2000. Web. March 2015.

- Establishment of a deferral account amortized over the time between the development period and the end of EGNB's general franchise agreement.

As part of the general franchise agreement awarded by New Brunswick, EGNB expected its capital structure would be organized with a 50:50 debt to equity ratio. For rate setting purposes, the agreement between the Province and EGNB originally provided for a deemed cost of debt that would be equal to the 10-year rate on a Government of Canada bond plus 2.5 percent. However, in its June 23, 2000 decision, the Board ruled that the cost of debt would be limited to the borrowing rate of EGBN's parent company, Enbridge Inc., plus 1 percent.[102] A return on equity of 13 percent was established for the development period.[103] Following EGNB's rate hearing, and there being no objections from intervenors, the Board found that it would use EGNB's actual debt to equity ratio rather than a target ratio – but with an equity amount not to exceed 50 percent.

Figure 12: Enbridge Gas New Brunswick Service Areas



Source: Enbridge Gas New Brunswick, 2013 Annual Report

3.6.5 Regulatory Issues

3.6.5.1 Streamlined Regulatory Process

EGNB filed its rates application on December 31, 1999 and the Board's decision was issued on June 23, 2000. In several places in that decision, the Board acknowledged that "the use of traditional regulatory methods may not be appropriate in the early years of developing the industry."[104]

[102] Ibid. Pg. 25.

[103] Any earnings above the permitted rate of return were to be applied directly to paying down the deferral account.

[104] Board of Commissioners of Public Utilities, 2000. Pg. 5.

Examples of traditional regulatory processes where the Board said it had been, or would be, flexible include:

- The Board asked parties to provide necessary information as quickly as possible to speed up decision-making;
- The Board established a committee process to resolve issues outside of the formal regulatory process to speed up decision-making and to reduce cost; and,
- The Board recognized that full public hearings on all rate changes could "add excessively" to the costs of regulation.[105]

The Board also said that the regulatory framework described in its June 23, 2000 decision – which is outlined in the other sub-sections below – would provide "the proper balance between minimizing regulatory oversight and protecting the public interest."[106]

3.6.5.2 Development Period

Transitioning from a greenfield situation to a developed natural gas distribution system involved a number of risks. The price of natural gas fluctuated. There would be competition from existing players, such as fuel oil distributors, who would seek to retain their customers. Significant losses were expected in the initial years of development due to start-up costs. Therefore EGNB argued before the Board that to respond to these potential issues it required flexibility for an extended period of time. The period of time between the start of development and when the utility could be regulated on a cost-of-service basis as a mature utility was deemed to be the development period. To the Board, a mature utility implied one that could be expected to recover its full costs of service on an ongoing basis. EGNB estimated this would take 8 years.

In response, the Board agreed that a development period was appropriate but it did not agree to the initial 8-year request.[107] Instead the Board set a five-year deadline of December 31, 2005, after which the burden of proof would be on EGNB to justify an extension. The Board's June 23, 2000 decision notes that there was "considerable discussion" about how the end of the development period should be determined. Samples of the criteria to be considered at a later time, in consultation with EGNB, were:

- Customer attachments;
- Rate of return on equity;
- Ability to forecast accurately;
- Volumes of gas flowing; and,
- Economic environment.

EGNB first applied to the Board in October 2004 to extend the development period from December 31, 2005, to December 31, 2010. In support of its application, EGNB cited lower levels of customer conversion and throughput than originally forecast, as well as higher per-unit costs. The Board granted this application and extended the development period to 2010.

In 2008, in advance of the expiry of the extended deadline in 2010, the Board scheduled a hearing to address the issue of the development period. The purpose of the hearing, which was a public proceeding, was to establish criteria for evaluating when the development period should end. In a December 1, 2009 decision, the Board found that while issues like the ones listed above are important considerations, they do not provide a basis by which to determine whether a *developing*

[105] Ibid.

[106] Ibid.

[107] Ibid. Pg. 8.

utility can be treated as a *mature* utility. Rather the Board devised a two-part test to distinguish between development and maturity:[108]

- Can the utility's revenues recover its full costs on an annual basis?; and,
- Are those revenues sustainable?

The first part of the test requires a comparison of revenues to costs – if revenues are equal to or greater than costs, the first part of the test is satisfied. The second part of the test requires a determination of whether or not revenues will continue to be equal to or greater than costs going forward. In determining sustainability, the Board further explained:

> "With respect to the appropriate period of time, the Board believes that use of a forecast period of two years is reasonable. The Board finds that the rates that could be charged on a sustainable basis are to be determined by using the approved rate setting method in force at the time of performing the test."[109]

In the Board's 2009 decision, it directed EGNB to file evidence by January 2010 on:

- The utility's cost of service;
- Proposed customer classes;
- Proposed rate design;
- Possible impacts of having different rate setting methods for different customer classes; and,
- A 10-year forecast identifying:
  - Number of customers for each class;
  - Throughput for each class;
  - Rates EGNB expects to charge;
  - Costs for each major expense category; and,
  - All other relevant information.[110]

Between the Board's 2009 decision and the present, the legislative and regulatory context in which EGNB operated changed, particularly with respect to how the deferral account (discussed in *Section 3.6.5.6: Establishment of a Deferral Account* below) is accounted for in setting rates. As a result, the Board ordered EGNB to file a new application by June 1, 2015 to determine the expiry of the development period.

3.6.5.3 Market-Based Approach to Rates

The market-based approach to rates proposed by EGNB, and subsequently approved by the Board, worked by setting targets for the all-in delivered price of gas vis-à-vis competing fuel sources (e.g., 30 percent below fuel oil costs in the residential market for those customers that had previously used fuel oil). The purpose of this approach, which would be applied on a "postage stamp" basis, was to incentivize customer conversion. Targets were set separately for each customer class, based on customers' avoided cost of either electricity or fuel oil and on assumed efficiencies for conversion of fuel or electricity to heat. While targets could be adjusted yearly to respond to market conditions, EGNB could not charge its customers any *more* than the targets established for a given year.

[108] New Brunswick. Energy and Utilities Board. "In the Matter of a Review of Issues Related to the Development Period for Enbridge Gas New Brunswick Limited Partnership." *Decision.* EUB, 1 December 2009. Web. March 2015.

[109] Ibid. Pg. 5.

[110] Energy and Utilities Board, 2009. Pg. 8.

A challenge with the market-based rate structure is that it meant that the rates that could be charged were very dependent on the commodity cost differential between natural gas and fuel oil. Natural gas prices increased dramatically in the early years of the development period. As a consequence, the all-in delivered cost of natural gas, particularly for residential consumers, was constrained by the 30 percent target savings required vis-à-vis fuel oil. This limited the amount that could be paid toward distribution services, since natural gas commodity costs still had to be recovered within the overall rate structure. The result of adverse commodity price movements was an increase in the distribution costs accumulating in deferral accounts.

In recent years, even with the decline in natural gas commodity costs, prices to residential consumers have continued to be constrained by the target price. Residential consumers therefore did not appear to benefit from lower gas commodity costs. Rather, the decline reduced amounts that were transferred to deferral accounts or that were borne by other customer classes. Distribution tariffs collected from residential consumers have continued to be below those that should be charged based on a full cost of service study, taking into account an appropriate allocation of costs among individual customer classes. Other customer classes have paid more than their share of the utility's costs, resulting in significant cross-subsidization among classes. This is observed through revenue to cost ratios that differ significantly from 1.0.[111] This has recently resulted in some large customers, notably Atlantic Wallboard Limited ("Atlantic Wallboard"), a subsidiary of J.D. Irving Ltd., seeking to exit the system. In response to a May 2014 increase to its distribution rates, Atlantic Wallboard, EGNB's largest customer, announced it would replace gas supplied by EGNB's system with compressed natural gas supplied by truck, which is not prohibited under New Brunswick's rules. The company claims it can save one million dollars a year with the change.[112]

Delays in market penetration may also have been the result of decisions on market structure. As noted above, the province implemented an open-access retail market as part of the new industry structure. The province envisaged that multiple retailers would compete for commodity supply and for related services, such as the sale of new gas appliances and furnaces. EGNB was therefore limited to the "default" supply of natural gas commodity and rules limited its ability to provide services that might be construed as providing unfair competition to retail energy suppliers. It can be argued that these constraints limited EGNB's ability to promote natural gas conversion.

3.6.5.4 Rate Riders During the Development Period

The Board approved the potential use of rate riders during the development period. This was meant to provide further flexibility to incentivize customer conversion. Rate riders were intended to be negative and used as necessary to provide further price reductions to one or more rate classes if required to respond to changing market conditions. Any shortfalls associated with the use of rate riders would be added to the deferral account. In 2014, in response to the changes in how the deferral account was accounted for in rate setting, EGNB requested and the Board approved the discontinuation of rate riders.

3.6.5.5 Postponed Cost of Service Studies

The Board granted EGNB's request to delay filing cost of service studies (revenue-to-cost ratios) until closer to the end of the development period. EGNB argued, and the Board agreed, that they would be of limited practical value at the beginning of greenfield development.

[111] Enbridge Gas New Brunswick. "Section 1.0 Application." *Review of 2013 Regulatory Financial Statements/ 2015 Rate Application*. Enbridge Gas New Brunswick, 27 June 2014. Web. March 2015. Pg. 4.

[112] K100 News. "Enbridge loses big customer." K100.ca. 26 May 2014. Web. March 2015.

3.6.5.6 Establishment of a Deferral Account

In recognition that EGNB's costs would be greater than revenues during the early years of the development period, the Board ruled that these costs could be deferred for recovery in the future. EGNB had originally proposed a 40-year amortization period and the use of two deferral accounts[113]:

- A Pricing Deferral Account ("PDA");
  - Including the deficiency caused by the Target Rates being established at a level that did not recover the full cost of service; and,
  - Including the deficiency resulting from the Actual Rates being lower than the Target Rates after Rate Riders had been used during the year; and,
- A Forecast Discrepancies Account ("FDDA").
  - Including the differences between actual and forecast revenues and cost of service that did not take into account any rate reduction that EGNB had to make to the Target Rates during the year which had to be captured in the PDA.

However the Board denied these requests. There was "no justification" for separating the deferral account "particularly for regulatory purposes". Instead the Board directed EGNB to establish one deferral account to record differences between Board-approved revenue requirements and the actual revenue EGNB received. The Board also expressed concern that, with respect to the amortization timeline, "such a long period of amortization will not necessarily be in the best interests of consumers."[114] The Board ruled instead that the deferral account would be required to be cleared by the end of EGNB's general franchise agreement in 2020.

Through the deferral account, costs that could not be recovered from consumers in the early periods, given the need to keep rates at or below target levels, would be deferred until future years for recovery then. The deferral account recognized the reality that EGNB's total annual Revenue Requirement, based on cost of service principles, was greater than the actual revenues that could be raised from consumers in the early years. This reflects the fact that, while in the development period, the company had made large investments in new physical plant but still had a limited number of customers from whom to collect the associated costs. Amounts transferred to the deferral account were allowed to accrue interest at a rate equal to the utility's deemed cost of capital. This was to ensure that EGNB would be compensated for the delay in receipt of associated revenues.

As noted above, as a result of lower levels of customer conversion, less throughput and higher per-unit costs than originally forecast, EGNB applied to the Board in October 2004 to extend both the development period and the amortization period of the deferral account. EGNB argued extending the deferral account amortization timeline from the end of the franchise agreement in 2020 to the year 2040 was required because:

> "It has become practically impossible for EGNB, without violating essential precepts of EGNB's rate/ business model, to recover the Deferral Account before the end of the term of the initial General Franchise Agreement."[115]

EGNB argued that in order to pay down the deferral account by 2020 it would require the utility to charge rates in excess of the market-based approach, thereby making the challenges facing the utility even worse. The Board ruled in favour of EGNB's request. In its decision, the Board noted the

[113] Information summarized from the Board's June 23, 2000 decision. Pg. 29.

[114] Ibid. Pg. 31-32.

[115] Enbridge Gas New Brunswick. *Application to Extend the Development Period and the Deferral Account Recovery Period*. EGNB, 8 October 2004. Web. March 2015.

discrepancy between what EGNB had originally forecasted as the peak amount of the deferral account ($13 million) and the forecasted peak at that time, which was $132.9 million.[116]

3.6.6 Outcomes

Today EGNB has approximately 12,000 customers in 10 New Brunswick communities, but its distribution system was built to serve a total of 30,000 homes and businesses.[117] The company's investment totalled more than $400 million and included construction of approximately 800 kilometres of distribution pipeline.[118] However EGNB's original proposal estimated that the utility could reach 70,000 consumers in 23 communities by the end of its franchise agreement in 2020. Hence, distribution build-out and market penetration have been much lower than were originally forecast.

Fuel-switching was slow to start in New Brunswick, and the specific causal factors have been debated in the years since. Contributing factors that have been cited include:

- The prevalence of many sparsely-populated communities, which increased the time and cost required to build out the distribution system and meant that fewer customers were passed by the system;
- The presence of existing home heating systems, such as electric baseboard, which increased customers' costs for conversion;
- Customer adoption projections that did not materialize;
- The structure of franchise agreements;
- Market-based rate structures;
- EGNB's build-out plans; and,
- Lack of effective regulatory and legislative oversight.[119]

From the perspective of the utility, a consequential decision was made early in New Brunswick's attempts to provide natural gas distribution. The Select Committee proposed, and changes to *The Natural Gas Act* included, the segregation of franchise agreements into three types:

- **General Franchise Agreement** – a franchise to distribute gas throughout New Brunswick;
- **Single End Use Franchise** – a franchise granted to a specific industrial facility; and,
- **Local Gas Producer Franchise** -- a franchise granted to a local gas producer.

In its 2011 submission to the New Brunswick Energy Commission, EGNB argued:

> "The New Brunswick natural gas distribution system operates under highly unusual conditions with the existence of single end use franchises that allow several large industrial users, representing more than 80 percent of the natural gas consumed in the province, to entirely bypass the system. Virtually all natural gas distribution systems in North America have been developed without single end use franchises. Consequently, these large users have never contributed to the development of the

[116] New Brunswick. Board of Commissioners of Public Utilities. "In the Matter of an Application dated October 8, 2004 to Request Extension of the Development Period and the Deferral Account Recovery Period." *Decision*. Board of Commissioners of Public Utilities, 21 January 2005. Web. March 2015.

[117] Enbridge Inc. *Annual Report*. Enbridge, 2013. Web. March 2015; and Enbridge Gas New Brunswick. "Natural Gas: A Strategic Piece of the Energy Puzzle." *Submission to the New Brunswick Energy Commission*. EGNB, 2011. Web. March 2015.

[118] Ibid.

[119] Atlantica Centre for Energy. "A Clean Break: Resetting the Natural Gas." *Distribution System in New Brunswick: Economic Development & the Public Interest*. Atlantica Centre for Energy, 3 June 2011. Web. March 2015.

> distribution system which has had a profound effect on how the system has developed to date."[120]

The original rationale for this market structure, as explained in a year 2000 New Brunswick Department of Natural Resources and Energy white paper:

> "The objective is to encourage large industrial customers to act as anchor loads in securing laterals and serves to satisfy the Province's desire to use the Maritimes and Northeast Pipeline lateral policy for as long as it is in effect. The single end use franchise fee was set at $50,000 annually, indexed to the consumer price index. This amount was determined as sufficiently large to ensure that small and medium-sized consumers would find value in being served by the distribution company while not being so high as to negatively impact the likelihood that large customers would become anchor loads to the laterals. In support of developing a safe and effective natural gas industry in New Brunswick, the Province will direct all franchise fees to help defray expenses of the Board, particularly for costs associated with pipeline safety."[121]

From the government's perspective, the issue of high distribution rates and low customer adoption was attributable to the continued use of market-based rate targets instead of the cost-of-service structure of mature markets. The unintended consequence, according to the Province's 2011 Energy Blueprint was that "the benefits of current and projected future low gas commodity prices are not being passed onto the consumer."[122]

As a response, the Government of New Brunswick tabled legislation in 2011 to change the way EGNB's rates were regulated, which in turn had the effect of disqualifying EGNB from using rate-regulated accounting.[123] EGNB was no longer allowed to build recovery of certain deferred costs into its rates going forward. This change resulted in EGNB writing off $262 million worth of assets. The company initiated legal proceedings against the Province for damages in breach of its contract. These proceedings continue to the present time.

3.6.7 Observations

Experiences with Enbridge Gas New Brunswick show the challenges of building a completely new distribution system on a greenfield basis. For example:

- EGNB's initial financial projections were built on the assumption that revenue shortfalls in the early years, relative to the utility's Revenue Requirement under traditional cost of service methods, could be deferred for recovery in later years. When circumstances changed such that shortfalls grew relative to forecast, this resulted in a rapid growth in deferral accounts to the point where they could no longer be easily recovered.
- Capital expansion costs proved to be higher than initially forecast. This was partly because of challenges associated with the local topography. Capital cost increases put additional pressure on the relative competitive position of natural gas service versus alternative, incumbent fuels and had a negative effect on the utility's financial position.
- The market-based rate structure resulted in large losses in the early franchise years and, in later years, the perception that savings from low gas commodity prices were not being passed onto consumers, which created a negative public perception toward natural gas fuel-switching.

[120] EGNB, 2011. Pg. 6.

[121] Natural Resources and Energy, 2000. Pg. 30.

[122] New Brunswick. Department of Energy. *The New Brunswick Energy Blueprint*. Department of Energy, October 2011. Web. March 2015. Pg. 26.

[123] Enbridge Inc., 2013. Pg. 77.

- Multiple franchises allowed industrial customers to by-pass EGNB's system. These customers could have been used as anchor loads, able to contribute to the development of the distribution system. An anchor load could have stabilized the financial performance of the utility service provider and potentially reduced the quantum of costs subject to deferral.

4 Observations

Based on our review of experiences with natural gas distribution system expansion in six other North American jurisdictions – Alaska, Connecticut, Maine, New York, North Carolina and New Brunswick – we provide a number of observations as outlined below. These observations may assist the Board in its consideration, as per its letter of February 18, 2015, regarding regulatory flexibility pertaining to proposed system expansion projects.

4.1 Summary Findings

- Although the extension of natural gas service to rural, remote or sparsely-populated unserved or underserved areas was a policy priority in all six case studies, no jurisdiction we evaluated was prepared to deviate significantly from the practice of using an economic test – based on a net present value calculation or similar metric – for determining whether a proposed expansion project should be approved. Policymakers and regulators were therefore challenged by the need to mitigate the upfront capital cost of expanding service, to encourage customer conversions and to maintain a rate structure that reflected well-established cost allocation and rate-design principles.
- We did not observe an explicit preference in the jurisdictions examined for inviting new entrants, creating new service territories or using municipally-based systems to address a lack of service in rural areas. In Alaska and Maine, new entrants competed alongside incumbents and were awarded franchise areas based on the merit of their respective proposals. In Connecticut, New York and North Carolina, the tools and approaches used to encourage the extension of natural gas service either favoured or were directed at incumbents. This may reflect the economies of scale typically associated with network monopolies such as natural gas distribution, even when service is being expanded into unserved areas.
- While broader public policy goals were important to local decision-makers in all of the jurisdictions we examined, decision-makers were generally not willing to broadly socialize the costs associated with extending service to areas that did not pass the economic test over the existing natural gas distribution grid and existing natural gas distribution customers. The tools and approaches used in each of the case studies we examined implicitly recognized that customers have access to alternative fuels. As such, the overall system cost, on a bundled basis, needed to remain competitive with alternative energies.
- There was an emphasis across jurisdictions on identifying and prioritizing industrial, commercial or institutional anchor loads. These large-scale users of natural gas, with consistent and predictable consumption, served as the basis for further retail-oriented expansion in a given area. Anchor customers often are in a position to make long-term commitments to natural gas service, see significant savings from conversion early and can help to defray a large portion of the expansion costs.
- With the exception of North Carolina, where certain refunds/ monies were made available to natural gas distributors from the upstream transportation sector, none of the jurisdictions we examined were willing to impose a surcharge or subsidy on the commodity cost of natural gas to fund system expansions. This is consistent with the evolution of rate regulation such that commodity costs are generally a straight pass through to customers without mark-up, and distribution system costs are determined on a stand-alone basis.
- Regulatory commissions have approved expansion programs in response to executive or legislative mandates, requests from existing franchised utilities or from potential new entrants or on their own initiative. To facilitate expansion efforts, regulators experimented with time-limited, project-specific innovations that demonstrated flexibility with respect to (i) relaxed criteria for approving expansion; (ii) inclusion of future construction financing through temporary surcharges; (iii) extended development periods to achieve profitability; and, (iv) new entrants willing to accept reduced rates of return on equity.

- A move to more transparent reporting was a feature of the policy frameworks in Connecticut, New York and North Carolina. The policymakers or regulators asked for periodic reporting on the number of requests received from potential customers in unserved or underserved areas (e.g., anchor loads, rural communities). This allowed policy makers to review progress toward intended goals and aided in modifying new approaches during the early stages of expansion programs.
- Examples of government assistance and the levels of public funding, if applicable, varied from jurisdiction to jurisdiction and over time. Some jurisdictions were willing to use the government's ability to borrow at lower rates in order to help finance expansion projects, thereby reducing utilities' weighted average cost of capital. In turn, a requirement for lower returns improves outcomes under existing economic tests associated with new service expansions. Other examples of government support included direct on-lending of funds raised through public sources and indirect grants funded outside of target development areas.
- Extending gas distribution systems into unserved or underserved areas has a risk profile that is greater than the risk of the existing system, on average. Extensions potentially span multiple years and rate-setting cycles. Project risks include (i) lower than forecast customer conversions; (ii) under-recovery of the revenue requirement associated with the cost of service, including the return on and of capital, and the potential stranding of assets and of regulatory deferral accounts; (iii) capital cost overruns; (iv) policy risk; and, (v) regulatory risk.
- With the exception of the major greenfield development in New Brunswick, we did not observe an extensive use of deferral and variance accounts to postpone the recovery of costs associated with natural gas system expansions. As noted in our section on New Brunswick, reliance on deferral accounts can create significant financial challenges when actual results vary from forecast.

Overview of Jurisdictional Review of Natural Gas Distribution System Expansions

Jurisdiction	Starting conditions	Enabling legislation or policy support	New entrant integral to system expansion efforts	Regulatory flexibility around traditional economic tests	Other notable features
United States					
Alaska	• Very few customers outside of downtown Fairbanks with access to natural gas.	• Interior Energy Plan	• Yes, the creation of a new municipally-owned LDC – Interior Alaska Natural Gas Utility.	• Regulator's decision based upon competing proposals to supply same area.	• LNG used to supply remote, underserved area.
Connecticut	• 216,000 customers on-main but not converted. • 89,000 off-main but considered feasible.	• Comprehensive Energy Strategy	• No, program relied on incumbent utilities.	• Proposed extension of payback period used in hurdle rate tests; alternative rate riders; flexibility in calculating extension costs.	• Proposal to require LDCs to submit annual expansion plans tracking multiple factors.
Maine	• Only one out of twenty households use natural gas for space heating.	• Long-standing policy favouring competition. • Non-exclusive gas franchise territories. • In 2012, legislation authorized state bond financing for expansion projects.	• Yes, approval of Summit Natural Gas of Maine to service 17 communities in central Kennebec Valley.	• Approval of utility-specific 10-year rate proposal, including CIAC charges rolled into rates and reduced ROE.	• "Second utility" status allows new entrants to serve alongside incumbents.
New York	• One million households without gas located within existing service territories.	• New York Energy Highway Blueprint • PSC Technical Conference to review natural gas policies.	• No, program relied on incumbent utilities.	• Use of 10-year development period (instead of five years) enabled proposal to satisfy economic test.	• Several utilities in New York State. Public Service Commission regulates 19 LDCs.
North Carolina	• In 1989, 38 counties out of 100 with no or minimal gas service. • 20 of the 38 counties in unfranchised territories.	• Natural Gas Planning Act, 1989 • Natural Gas Expansion/ Cost Act, 1991 • Clean Water and Natural Gas Critical Needs Bond Act, 1998	• No, program relied on incumbent utilities.	• Expansion funds and natural gas bonds used only for economically infeasible (i.e., negative net present value) portions of expansion projects.	• $510 million USD invested to expand gas distribution system: $200M from natural gas bonds; $115M from LDC expansion funds; $195M primarily from LDC investors.

Overview of Jurisdictional Review of Natural Gas Distribution System Expansions

Jurisdiction	Starting conditions	Enabling legislation or policy support	New entrant integral to system expansion efforts	Regulatory flexibility around traditional economic tests	Other notable features
Canada					
New Brunswick	• Greenfield situation. • No existing natural gas distribution system. • Construction of the MN&P pipeline.	• Select Committee recommendations • Government RFP to award franchise • Gas Distribution Act, 1999	• Yes, Enbridge Gas New Brunswick received General Franchise, subject to Single End Use and Local Gas Producer Franchises.	• Extended development period; market-based rate; deferral account for unrecovered revenue requirement.	• Subsequent legislative changes made to original franchise agreement resulting in protracted legal dispute.

Overview of Expansion Results

Jurisdiction	Utility	Customers added to date	Original projections	Type/ amount of government assistance	Total Project Cost
Alaska	• Interior Gas Utility	• 0 • Expected Q3 of 2016	• 1,403 by 2018 • 13,336 by 2022	• $150 million in loans for expanding local distribution system	• $360 million for total Interior Energy Plan
Connecticut	• Various	• Not available	• ~300,000 by 2020	• Proposals aimed at accelerating customer conversions with on-bill financing	• ~$1.44 billion to serve all off-main customers
Maine	• Summit Natural Gas of Maine	• 1,500 in Kennebec Valley • 1,500 in CFY[1]	• 52,000 potential in Kennebec Valley • 8,000 by 2018 in CFY[1]	• Not applicable	• $350 million for Kennebec Valley Project • $72.5 million for CFY[1] Project
New York	• New York State Electric & Gas	• Not available	• 1,200 (potential) by 2017	• Not applicable	• $9 million
North Carolina	• Various	• 5,612 customers[2] • 6,719 customers[3]	• Not available	• $200 million in natural gas bonds	• $510 million total: $200M from natural gas bonds; $115M from LDC expansion funds; $195M primarily from LDC investors
New Brunswick	• Enbridge Gas New Brunswick	• 12,000 customers • 10 communities	• 70,000 by 2020 • 23 communities	• Not applicable	• EGNB investment to date of $400+ million

[1] Cumberland, Falmouth and Yarmouth, Maine
[2] Includes residential, commercial and industrial customers from LDC expansion funds (as of December 2011)
[3] Includes residential, commercial and industrial customers from natural gas bonds (as of December 2011)

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Appendix 1 Other Jurisdictions

This section provides an overview of policies in other jurisdictions with respect to the expansion of natural gas distribution systems. Some of these policies are already in place, while others are under consideration.

Canada

Alberta

There are more than 50 rural gas co-ops in Alberta. These co-ops formed throughout the 1960s and 1970s in response to the lack of distribution services in rural areas.[124] In 1973, the provincial government created the Rural Gas Program, which allowed rural gas co-ops to form exclusive franchise areas. The program also included government assistance in the form of grants for extending gas lines to rural farms and households. This assistance, which continues today as the Rural Gas Grant Program, is intended to partially offset the costs of construction for extending new service. Eligible rural utilities – co-ops, municipal or First Nations – can apply for funding under a formula. As of 2013, 75 percent of costs above the threshold of $6,000 per residence or farm is eligible for support. Where costs exceed $20,000, anything above that threshold is ineligible for the grant. Today, the Federation of Alberta Gas Co-ops Ltd. is responsible for administering the Rural Gas Grant Program, while the provincial government remains the source of funding.

Saskatchewan

From 1982 to 1991, Saskatchewan extended natural gas distribution services to rural communities under the Rural Gas Distribution Program, which provided government assistance for the installation of gas lines. The Saskatchewan Association of Rural Municipalities is currently lobbying the provincial government to reintroduce the program. [125] Today, SaskEnergy – the province's gas LDC, a provincial Crown corporation – reaches 93 percent of Saskatchewan residential, farm, commercial and industrial customers. Service reaches all but the most northern and remote communities.[126] While SaskEnergy management has explored future expansion to some of these communities using LNG, these plans are still in the preliminary stages.[127]

United States

Delaware

Delaware's *2009-14 Energy Plan* included the policy goal of facilitating the expansion of natural gas transmission and distribution. However, given Delaware's small geographic size, state policies are primarily aimed at infilling underserved areas, as opposed to reaching remote, rural or sparsely-populated unserved areas.

Indiana

In Indiana, utility extension projects into rural areas are eligible for rate adjustments, or trackers, called Transmission, Distribution and Storage System Improvement Charges ("TDSIC"). The Indiana Utility Regulatory Commission reviews 7-year infrastructure improvement plans filed by utilities

[124] Background information in this section is primarily derived from the Federation of Alberta Gas Co-ops Ltd. *Source*: Federation of Alberta Gas Co-ops Ltd. "Federation History." *Who We Are*. Federation of Alberta Gas Co-ops Ltd., 2015. Web. March 2015; and Federation of Alberta Gas Co-ops Ltd. "Rural Gas Grant Program." *Public Info*. Federation of Alberta Gas Co-ops Ltd., 2015. Web. March 2015.

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seeking to use this rate mechanism. If approved, TDSICs may be used to finance rural expansion projects subject to a variety of conditions, such as (i) rate increases limited to once every 6 months; (ii) rate increases limited to no more than 2 percent of total annual retail revenues; and (iii) utilities can recover 80 percent of costs as incurred, with the remainder deferred until the next base rate case.

Michigan

Michigan has well-developed production, transmission and distribution infrastructure that reaches most of the state population, including the Upper Peninsula, through 10 LDCs. While new legislation was before the Michigan legislature in 2014 to encourage additional residential propane-to-gas conversions – and estimates are as high as 200,000 potential new gas customers – state initiatives are primarily related to in-filling underserved areas as opposed to reaching remote, rural or sparsely-populated unserved areas.

Minnesota

Instead of requiring upfront payment for the uneconomic portions of expansion projects, Minnesota allows utilities to apply "New Area Surcharges" to all customer bills within the expansion area. These surcharges last for a flexible, project-specific period of time (e.g., until all uneconomic costs are recovered) and/ or for a fixed period of time (e.g., as long as 20 years in some cases).

Mississippi

Mississippi is a significant regional hub for natural gas infrastructure and is seeking to leverage its gas distribution system to encourage economic growth. One LDC (Atmos Energy Corp.) has been granted approval to charge all of its existing customers a "Supplemental Growth Rider" to finance the uneconomic portions of extensions to industrial anchor loads.

Nebraska

Nebraska passed legislation in 2012 allowing utilities to apply a "Rural Infrastructure Surcharge" to customers within an expansion area and, if necessary, apply the surcharge to a broader set of utility customers.

New Jersey

The 2011 New Jersey Energy Master Plan included the policy goal of expanding natural gas distribution services to unserved areas – primarily in Southern New Jersey. However, interstate transmission pipelines and the role of natural gas in electricity generation are bigger priorities for state policymakers. New Jersey already has one of the highest concentrations of natural gas use in the U.S., according to the plan, with 70 percent of residents using natural gas for home heating.

Ohio

In 2014, Ohio lawmakers passed a bill permitting natural gas companies to apply infrastructure development riders to recover costs of extending gas distribution services to economic development projects. Eligible economic development projects included commercial, industrial and manufacturing facilities, as well as projects in areas where adequate natural gas infrastructure was not available. These riders can be applied to all customers of the natural gas utility, as approved by the Public Utilities Commission of Ohio.

Appendix 2 New York Public Service Commission Discussion Questions

In advance of its January 9, 2013, technical conference on natural gas expansion, the New York State Public Service Commission issued the following list of questions to participants for further discussion. These questions originally appeared as an appendix to the order instituting the proceeding, dated November 30, 2012, and are presented here in the same way.

ISSUES TO BE CONSIDERED AT THE TECHNICAL CONFERENCE

Barriers to Extension and Expansion of Natural Gas Facilities

1. Please explain your understanding (and for utilities, your implementation) of Commission regulations and the Natural Gas Expansion Policy including your views on whether they encourage or deter expansion of the natural gas delivery system in New York State. Do you feel that the Commission regulations and Policy should be modified and if so, how?

2. Regarding the Commission's regulations of the natural gas delivery system and the system itself, do you believe that the interests of utility shareholders, ratepayers, and the State as a whole are aligned? Please explain.

3. Are there provisions of current policies or regulations that appropriately incentivize the expansion of the natural gas delivery system in New York State? Are these sufficient? If not, please suggest alternatives.

4. Identify current barriers inhibiting conversion to natural gas usage from other heating fuels – other than the cost of replacing heating equipment. Please explain how the barrier inhibits conversion and provide suggestions for reducing or eliminating the barrier – including the cost of replacing heating equipment.

5. Please identify the outreach and education efforts currently employed by the utility for the purposes of gauging interest in natural gas service and/ or soliciting new customers in areas where interest in the possibility of obtaining service has been expressed. Are the efforts sufficient? How can they be improved? Would expanded or improved outreach and education programs increase conversion to natural gas by customers who reside within the 100 feet zone of existing utility infrastructure (and, accordingly would not pay for the extension)? How can the utility identify, communicate and engage with such customers? When an individual customer requests service, please describe the utility's efforts to communicate with or solicit other customers in the neighborhood/ area.

6. Please identify the typical flow of communication and information between the utility and a customer requesting service that would require extension of a gas main sufficient to require a surcharge. Please provide any examples of written communication.

7. What issues should be given consideration prior to expansion of the natural gas delivery system? Should such considerations include protections for a group or groups of customers? If so, what should be and what types of protections should be considered?

8. Are there existing utility specific pilot programs focused on new approaches to line extensions or new franchise expansions of the natural gas delivery system? If so, please describe the pilot program. If not, could such a pilot program be beneficial and, how would it be designed?

Rate and Ratepayer Considerations

9. The Commission's regulations (§230.2[f]) provide that "each corporation may, in its tariff schedules, extend such obligation [to provide certain main and service line extensions without cost to the customer], to the extent the provision of additional facilities without charge is cost-justified." Identify whether the utility ever provides residential customers with more than 100 feet of gas main or service line without surcharge. Please explain why and under what circumstances or, if never, why not. Is the utility aware of any geographic areas in its service territory where potential cost justified extensions of greater than 100 feet are currently un-served? If not, has the utility ever attempted to ascertain or develop such information? What should be the appropriate length of main and/or service provided without surcharge? Please explain.

10. Does the utility provide programs that could assist low income customers or those on a fixed income to overcome the barriers to conversion to natural gas?

11. Are there potential funding mechanisms for expansion of the natural gas delivery system other than through utility rates or direct customer payments (surcharges, CIACs or other)?

12. Are existing natural gas efficiency programs adequate and optimal to serve the expansion of customers within 100 feet of existing utility infrastructure? If not, what changes, including possibly the level of funding, could be made to improve the existing efficiency programs? Would efficiency programs targeted to conversion customers result in increased energy savings, and if so, how?

13. Do Revenue Decoupling Mechanisms (RDMs) impact expansion of the natural gas delivery system?

Economic Development

14. Does the utility have any information or estimates concerning the existence of commercial or industrial customers who may add and/ or retain jobs if they could switch their process or heating fuel to natural gas? If so, how many jobs might be added or retained?

15. Are there specific industries in the State that would benefit from an expanded natural gas delivery system? Please describe.

Public/ Private Partnerships

16. Are there potential partnerships between various entities involved in the energy and heating markets in New York State that could facilitate expansion of the natural gas delivery system? If so, please provide examples and whether your organization would be willing to take part in such a partnership. Who would be best suited for encouraging and developing such partnerships? What role should the public sector play?

17. Are there programs currently administered by utilities or federal, state or local agencies that assist customers with heating fuel conversions? Are there roles that other agencies, such as the New York State Energy Research and Development Authority (NYSERDA), should play in expansion of the natural gas delivery system? Should the Energy Efficiency Portfolio Standard (EEPS) programs be expanded or modified to encourage conversions to natural gas before end-of-life replacements?

18. Are there opportunities to coordinate natural gas delivery system expansion projects with other available resources, such as economic development, energy efficiency, or environmental protection? Please provide specific examples, if possible.

Environmental Impact

19. Are there changes that could be made to the environmental impact review process involved in granting or expanding gas franchise areas that could improve or streamline the process?

20. Please identify, if any, areas of the State where provision of natural gas delivery service is unrealistic because of environmental constraints, construction permitting requirements or other factors and explain why service to such areas is believed to be unrealistic. Are there any areas of the State that require special consideration regarding expansion of the natural gas system?

Planning

21. Please explain your utility's natural gas delivery system expansion planning process including any large-scale and or long-term plans that are in place or are being considered.

Appendix 3 National Regulatory Research Institute Discussion Questions

Ken Costello's 2013 policy paper for the National Regulatory Research Institute entitled "Line Extensions for Natural Gas: Regulatory Considerations" was one of the most widely-cited sources during the course of our research. The paper concludes with a list of questions state utility commissions can ask about gas-line extensions. That list is presented here for further consideration.

QUESTIONS STATE UTILITY COMMISSIONS CAN ASK ABOUT GAS-LINE EXTENSIONS

1. What are the benefits and costs of line extensions from the perspectives of (a) the utility, (b) existing customers, (c) new customers, and (d) society at large (e.g., local economy, accounting for environmental benefits)? If they differ, what implication does this have for policy?

2. When should a utility extend its lines? What are the necessary conditions? What is efficient and economical service expansion?

- When prospective customers indicate their commitments to immediate demand?
- Before or ahead of known (i.e., firm, committed) demand but in potentially high-growth areas?
- If the latter, how should the utility recover any current or future revenue deficiencies?

3. What is the proper balance of risk and reward for the utility and its customers?

4. Should regulators distinguish between main lines in underdeveloped and undeveloped (e.g., rural locations without previous gas service) areas? If so, what are the implications for policy?

5. Who should pay for lines?

- How much should new customers pay?
- Existing customers?
- Utility shareholders, government taxpayers?
- What is a fair sharing of the costs?

6. How can a commission ensure a utility that it will recover all of its prudent costs for investments in line extensions?

7. Can subsidization of new customers ever be justified?

- What do we mean by subsidization in this context?
- Is this situation similar to the federal government subsidizing rural electric co-ops to expand electric service to areas that otherwise would not be served because of the unprofitability to investor-owned utilities?

8. How should the utility recover their costs from new customers?

- Through an existing ratemaking mechanism?
- Through some other mechanism (e.g., special surcharge)?

9. Should the utility recover any incremental costs from existing customers?

- Should existing customers be always held harmless when a utility extends service to new customers?
- If not, under what conditions?

10. Over what period should a utility recover the costs for line extensions that pass an economic test?

11. Should utilities offer "no cost" extension lines to new customers? If so, who should pay for them?

12. How should utilities structure customer contributions?

- What is their rationale?
- How large should they be?
- Over what timeframe should utilities recover them (e.g., one-time up-front, amortized over five years)?
- Should they include refunds? If so, what are the criteria for refunds?
- How can utilities design up-front customer contributions so as not to discourage fuel switching to gas that is economical?
- Could customer contributions place utilities at a competitive disadvantage with other fuels?
- Under what conditions, if any, should regulators include facilities paid for by customer contributions in rate base?

13. Should regulators approve line-extension projects that may not be economically feasible using traditional criteria, like NPV and IRR?

14. What incentives and disincentives does a utility have to invest in new lines?

- What explains any distorted incentives?
- What can regulators do to eliminate them?

15. What are the line-extension policies of different gas utilities in your state?

- Do utilities have similar policies, or do they differ?
- What are the positive and negative features of each?

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Impact of Natural Gas Distribution Systems Expansion in Ontario

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March 2016

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Executive Summary

in January 2016, the Ontario Energy Board decided to establish a generic hearing to deal with issues arising from Union Gas Limited's Community Expansion Application (EB-2015-0179).

The Canadian Propane Association (CPA) engaged Gas Processing Management Inc. (GPMi) to evaluate Union's application and consider the impacts of potential natural gas distribution expansion in Ontario.

This report deals primarily with two issues. First is a discussion of various fuel costs for residential consumers in Ontario. By utilizing auto propane prices instead of residential propane prices, Union has overstated propane prices and potential fuel cost savings for switching from propane to natural gas. GPMi shows that the expected payout period for a switch from propane to natural gas will likely exceed 7 years. It is unlikely that customers will choose to make such a switch in the foreseeable future and therefore Union's connection forecasts are overly optimistic.

The second issue is a discussion of the economic harm to other fuel suppliers, including propane distributors in Ontario, as well as the overall economic impacts that result from expansions of natural gas distribution systems. The propane distribution industry generates significant economic value and jobs in Ontario. That value and those jobs are destroyed when natural gas utilities use cross-subsidization to finance uneconomic projects to expand their distribution systems to areas already economically served by alternate fuels. There would be economic value added if the existing systems were to be replaced by fair competition on a level playing field and if the new investments were economic. In the case where proposed projects are far from being economic on any realistic measure, the playing field is far from level. Consequently, utility shareholders win while utility customers and the overall economy lose.

Disclaimer

This report has been prepared by Gas Processing Management Inc. (GPMi) for the sole benefit of Canadian Propane Association with certain conditions relating to third party distribution. This report or any part of it shall not be provided to third parties without the express written consent of GPMi. This report may be provided to the Ontario Energy Board as part of the Ontario Energy Board Generic Proceeding – Natural Gas Community Expansion (EB-2016-0004). Any third party in possession of the report may not rely upon its conclusions without the written consent of GPMi.

GPMi conducted the analysis herein utilizing reasonable professional skill, expertise, diligence and care consistent with normal industry practice. All results are based on information available at the time the analysis was conducted. Changes in factors upon which the analysis is based could affect the results. Forecasts are inherently uncertain and GPMi accepts no liability with respect to the client's or any other third party's conclusions or decisions which are based on the analysis or forecasts herein.

Some of the information on which this analysis is based has been provided by others. GPMi has utilized such information without verification unless specifically noted otherwise. GPMi accepts no liability for errors or inaccuracies in information provided by others.

Data Sources

For the analyses in this report, GPMi has utilized public data from a variety of sources including the National Energy Board (NEB), Natural Resources Canada (NRCan), Statistics Canada, the U.S. Energy Information Administration and other sources.

Nomenclature

Terms and acronyms utilized in the natural gas liquids industry are often confusing. The context of the discussion frequently determines which terms are used. For, example, the terms "LP Gas" or "LPG" are often used in international markets and may refer to ethane, propane, butanes or mixtures of these products. In North America, the term "Natural Gas Liquid(s)", or "NGL", is often used and similarly, may refer to ethane, propane, butanes or mixtures of these products. All these terms may be used in this report and, while an attempt has been made to be consistent in their utilization, the author regrets any confusion that may arise. Also, please refer to the Glossary of Terms and Abbreviations.

Glossary of Terms and Abbreviations

AECO – The AECO "C" spot price is an Alberta natural gas trading price benchmark normally for natural gas on the TransCanada Alberta system.

cpg – cents per gallon; propane in the U.S. is often priced in cpg; always in U.S. currency

GJ – gigajoule; one billion (10^9) joules; a measure of heating value of hydrocarbon materials; a cubic metre of liquid propane contains 25.377 GJ; natural gas in Canada is often priced in $/GJ

Henry Hub - a natural gas distribution hub in Erath, Louisiana. The pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX) and the OTC swaps traded on the Intercontinental Exchange (ICE).

kbbl – thousand barrels

kbpd – thousand barrels per day

LNG – Liquefied Natural Gas

LPG or LP Gas – Liquefied Petroleum Gas; usually propane, butane and mixtures thereof; an acronym often used in international markets

m^3 – cubic metre

MB – Mont Belvieu, Texas. Encompasses a large concentration of NGL gathering, storage, fractionation, distribution and export facilities.

MMBtu – million Btu; natural gas in the U.S. is often priced in $/MMBtu

NGL – Natural Gas Liquids; ethane, propane, butanes or mixtures thereof; an acronym often used in North America

Rich gas – natural gas that contains relatively high levels of entrained NGL

Spec – specification products, e.g., spec propane, that meets minimum quality specifications

USGC – U.S. Gulf Coast

WTI – West Texas Intermediate; a grade of crude oil used as a benchmark in crude oil pricing

I Introduction

In July 2015, Union Gas Limited (Union) filed an application with the Ontario Energy Board (OEB) seeking approval of its proposed Community Expansion Program to expand natural gas service to specified rural and remote communities in Ontario[1]. Union proposed changes to how expansion projects are typically funded. Union sought to change the financial viability tests established by the OEB for natural gas distribution system expansion. The change would result in existing Union customers paying a portion of the costs of expansion to new communities. In December 2015, the OEB held a Technical Conference and in January 2016, the OEB ordered that the Union application be put on hold and a "generic hearing" be held.

The Canadian Propane Association (CPA) engaged Gas Processing Management Inc. (GPMi) to evaluate Union's application and consider the impacts of potential natural gas distribution expansion in Ontario.

Section II of this report discusses comparison of fuel costs for residential consumers in Ontario.

Section III discusses the economic harm to other fuel suppliers, including the propane distributors in Ontario, as well as the overall economic impacts that result from expansions of natural gas distribution systems.

Section IV provides a summary of key conclusions and final comments.

[1] EB-2015-0179 – Union Gas Limited – Expansion of Natural Gas Distribution, filed July 23, 2015

II Fuel Cost Comparison

In its pre-filed evidence, Union presents a chart (Figure 1) with a 9 year history of the Estimated Annual Cost Energy of various fuels.[2] The chart illustrates a large gap between the annual cost of natural gas and the other fuels used by typical residential consumers in Ontario. Union suggests that in recent years the cost of other energy sources has increased while the cost of natural gas has declined "primarily as a result of abundant, lower-priced supplies located closer to Ontario becoming available." Presumably, they are referring to development of the Marcellus and Utica plays in the U.S.

In the next figure in the pre-filed evidence[3], Union uses their calculated 2015 fuel cost savings numbers to project 10 years of cumulative cost comparisons for a typical residential consumer. That figure shows that even with a relatively large up front conversion cost of $6,500, a simple "undiscounted" payback occurs at about 3.75 years for a conversion from other fuels to natural gas. In IR Responses, Union suggests that customers are reluctant to convert with payback periods longer than four years[4] and that a payback period in the 7 – 10 year range would mean that few customers would convert[5].

In response to an IR from the CPA, Union confirmed that the prices used for propane in their analysis were for auto propane, not residential propane[6]. Residential propane markets have very different characteristics than auto propane markets. Auto propane prices are not the same as residential propane prices and therefore, using auto propane prices to compare residential heating costs will give incorrect results.

Numerous factors affect retail pricing for various fuels. The propane distribution business in Ontario is competitive with a number of distributors competing on the basis of service and price for a more or less fixed number of customers. There is no public reporting of residential propane prices. However, in spite of the lack of price transparency, the market can be considered to be efficient because residential customers can easily change suppliers. This forces the distributors to compete on a variety of levels by providing different service plans, price and term incentives, etc. Many residential fuel customers prefer this more flexible type of market as opposed to the "one-size-fits-all" big utility cost-of-service approach for natural gas and electricity.

[2] Ibid., Exhibit A, Tab 1, Figure 1, at page 9 of 46

[3] Ibid., Figure 2, page 10 of 46

[4] Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B.CCC.7 pages 1 & 2

[5] Ibid., CPA.11 (e) page 3 of 3

[6] Ibid., CPA.2 page 1 of 1

In recent years, residential propane prices in Southern Ontario have been significantly below auto propane prices. In order to more correctly assess the comparative heating costs, several CPA members have provided actual residential pricing data to GPMi[7]. Utilizing actual residential propane prices makes a material difference to Union's conversion forecasts.

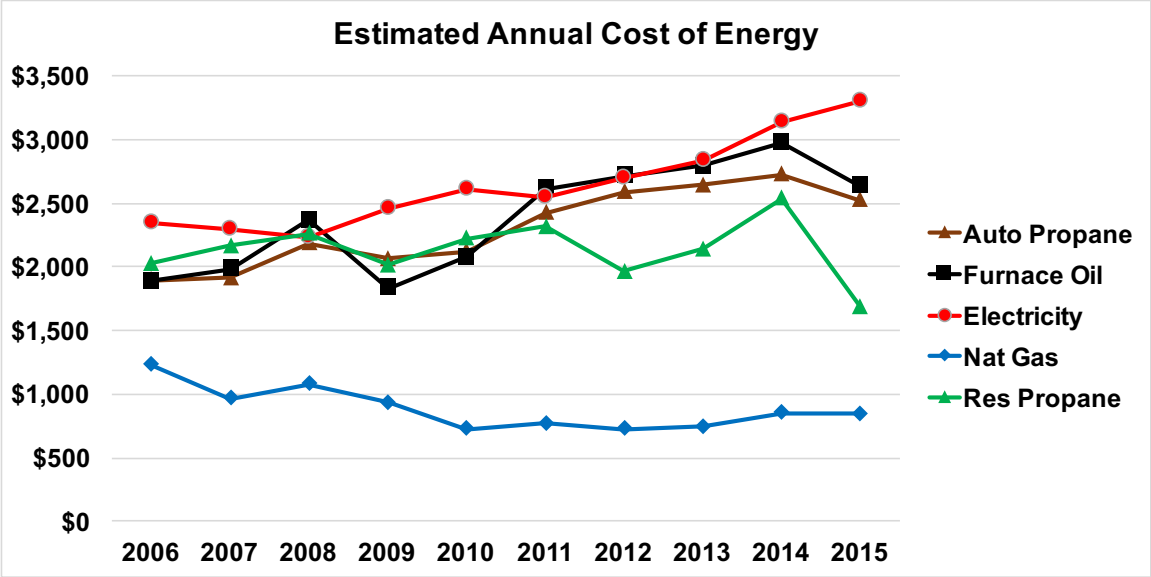

Figure 1 - Estimated Annual Cost of Energy

In Figures 1 and 2, GPMi has re-plotted Union's charts with the addition of a residential propane line in green. Several points can be taken from the charts. Prior to 2011, there was minimal difference between fuel costs based on auto propane prices and costs based on residential propane prices. However, since 2012, residential propane prices have been significantly lower than auto propane prices. Therefore, the current actual cost saving is not as large as suggested in Union's evidence. Furthermore, relatively lower propane prices, and a lower cost differential, can be expected to persist for the foreseeable future (see discussion below).

If the fuel cost savings are not as large, then as shown in the Cumulative Residential Energy Cost chart (Figure 2), the slope of the residential propane line is significantly lower. Based on residential propane prices, the crossover or breakeven point moves to around 7 years. In another IR response[8], Union indicated that if the full cost of its proposed expansion projects were to be recovered as an Aid-to-Construction (CIAC) then each customer would be

[7] The prices that propane distributors charge for residential service are proprietary, confidential and commercially sensitive. The data have been provided to GPMi in confidence and will not be divulged. The analysis presented herein is based on averages of the data provided.

[8] Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B.CPA.6

required to pay $16,470 to connect. In that case, the breakeven point moves to about 18 years.

With a long payback period and an expectation of relatively low propane and furnace oil prices for the foreseeable future, GPMi expects that few customers will choose to convert to natural gas service.

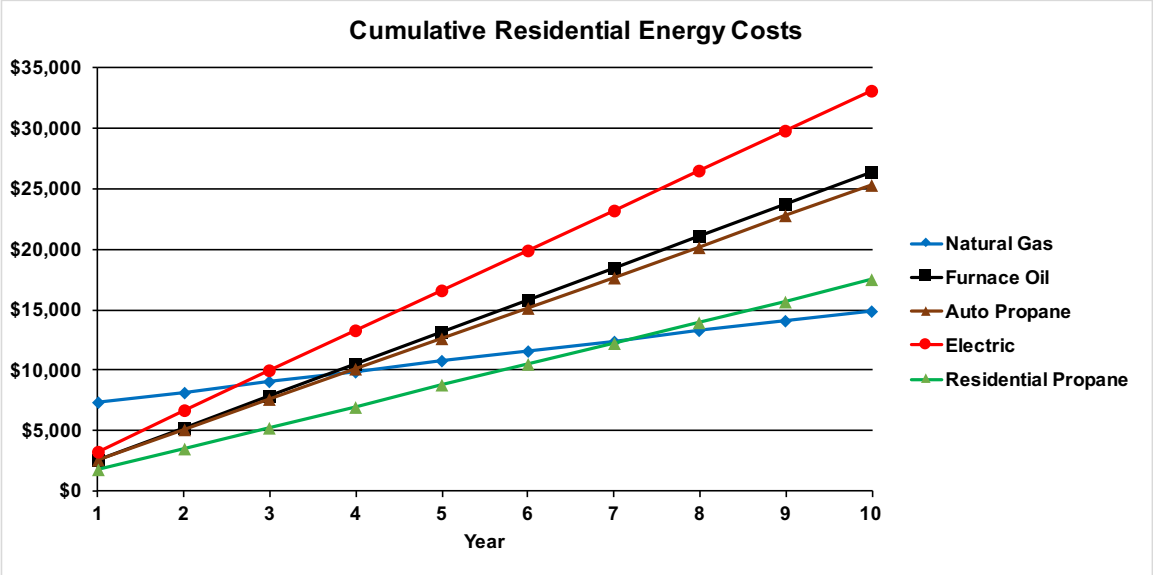

Figure 2 - Cumulative Residential Energy Costs

Relative Fuel Prices

Propane and natural gas prices have both fallen in recent years but in relative terms, propane has fallen more than natural gas. In the current low price environment, consumers should expect the current fuel cost differential to be more representative of the foreseeable future.

Wholesale propane prices are a function of both natural gas prices (feedstock cost) and crude oil prices (co-product cost). The development of horizontal drilling and multi-stage fracturing technologies has dramatically changed the hydrocarbon supply/demand picture in North America. In the 2008 to 2012 period the prices of hydrocarbon liquids, including natural gas liquids such as propane, were relatively high compared to natural gas[9]. Consequently, natural gas producers throughout North America targeted "rich" gas plays to capture the higher prices. This led to a glutted market and very low natural gas and propane prices[10].

[9] In industry parlance, the Oil/Gas Ratio was very high.

[10] The evidence for this statement is that prior to 2009, the U.S. was a net importer of LPG, but since 2012, the U.S. has become the world's largest LPG exporter on the basis of very cheap propane. U.S. propane export volumes are currently in the 700,000 bpd range which is more than 3 times total Canadian production of propane.

The following chart shows the ratio of Sarnia wholesale propane prices to Union's delivered gas prices[11]. The rise from 2008 through 2012 illustrates the higher liquids prices in that period and the decline since 2012 illustrates that propane prices have fallen much more than natural gas prices, relatively speaking. Commodity prices can be volatile and difficult to predict. However, given the very large supplies of hydrocarbons available in North America, it is unlikely that propane prices can be expected to rise materially versus natural gas prices for the foreseeable future[12].

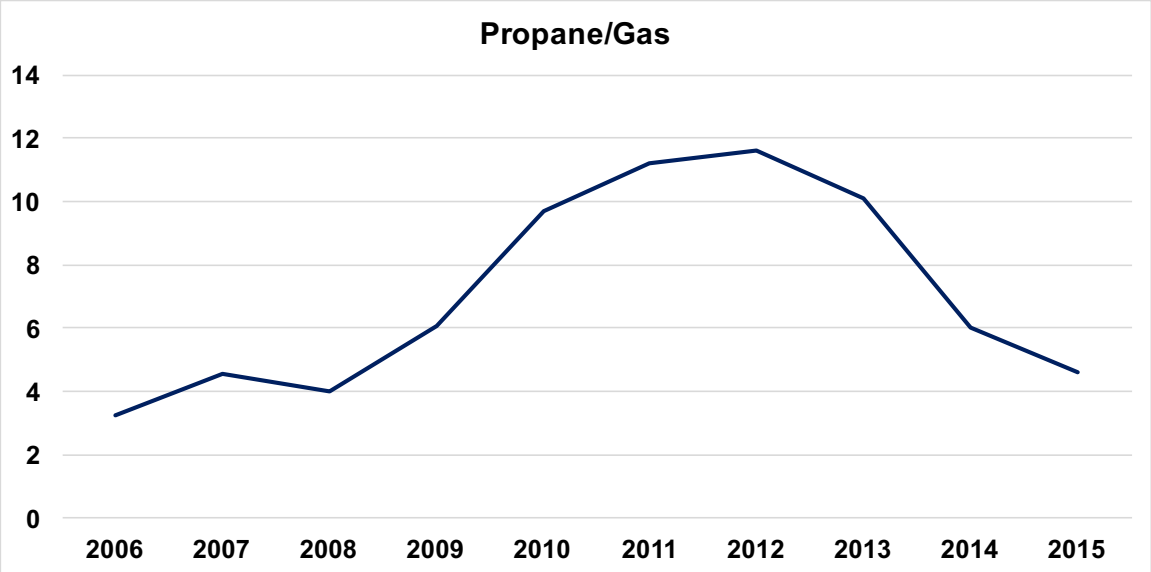

Figure 3 - Propane/Gas Price Ratio

In today's price environment, GPMi believes that there is not enough of a saving to justify switching away from propane to natural gas. If gas service were available for a consumer currently utilizing another fuel source, then the logical thing to do would be to wait to see how future prices unfold. If the other fuel prices rise relative to gas, then switch. If not, then don't do anything. That consumer has a free option that has been paid for by the other utility rate payers. The bottom line is that few customers will convert at least for the next several years.

Propane Penetration Rates

In the same IR response where Union confirmed that they used auto propane prices for their analysis, Union suggests that any auto vs residential price difference "…would not be material enough to cause a change in Union's proposal, given that the current penetration of propane equipment underlying

[11] Union price data from OEB Q3 2015 report. Sarnia propane price data from GPMi.

[12] A similar argument can be made for heating oil prices which are closely related to crude oil prices.

Union's proposal is only 15%..."[13]. The 15% figure appears to be from Union's 2011 Market Share Study[14]. Union also provides a summary of heating system penetration rates for five areas[15]. The reported propane penetration rates are Milverton - 30%, Prince Township - 14%, Lambton Shores - 53%, Kincardine Area - 21% and Kincardine Ripley Area - 20%. Additional data indicates greater than 40% for commercial consumers in the Kincardine area.

Assuming the survey data is representative, average residential penetration in the five areas is approximately 28% and commercial penetration is above 40%. GPMi believes that the penetration rate for propane heating systems is significant and for the reasons outlined above, very few of those customers are likely to convert to natural gas over the next several years. Consequently, Union's conversion, revenue and economic estimates are likely overly optimistic.

[13] Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B.CPA.2

[14] Ibid., Exhibit B.SEC.9, page 6

[15] Ibid., Exhibit B.South Bruce.6

III Economic Harm to the Propane Industry

Magnitude of Ontario Propane Industry

The Canadian propane industry has direct and indirect impacts on the Canadian economy. Direct impacts include purchases of propane for fuel and other uses as well as expenditures on items such as salaries and investments in construction and capitalized goods and services. Indirect impacts are the effect the direct expenditures have on other companies who increase their output to satisfy the increased demand for goods and services provided by the direct impacts. In addition, indirect impacts occur when consumer spending changes due to increased income resulting from salaries paid to workers supplying the direct and indirect goods and services.

GPMi has estimated the direct value of the propane industry in all the provinces of Canada based on calculations of the value of propane consumed in Canada plus the value of exports. The retail component is the largest contributor to the propane value chain in Canada at approximately 64%. This is the portion of value above the wholesale value of propane. The largest component of the retail value is the downstream handling and transportation of propane to final consumers.

Economic multipliers are often used to estimate the full economic impact of the contribution of a specific industry to the economy as a whole. For example, in the United States, the Propane Education & Research Council (PERC) has estimated that each dollar of direct expenditure and investment in the propane industry translates into an additional 1.54 dollars of activity giving a gross output multiplier of 2.54 for the economy. Economic multipliers are also used to estimate the impact on the number of jobs in an industry. Various multipliers, ranging from 1.5 to 3.0, are estimated for each component of the propane value chain.

GPMi estimates that the direct economic value of the retail propane business in Ontario was $532 million[16] in 2015. The total economic impact, after considering the influence of multipliers on different sections of the industry, was $1,285 million[17]. Auto propane demand is roughly 10% of the propane market in Ontario. Residential and commercial demand is approximately 40%. The remaining 50% is spread among agricultural, mining, manufacturing, petrochemical and construction demands.

The Canadian propane industry contributes to government revenues through taxes and royalties. The estimates above do not include income and other business taxes since they are often company and location specific. Therefore, the total tax contribution by the propane industry will be somewhat higher than this estimate.

[16] Transportation & Handling = $342 million, Retail Margin = $40 million and Retail Taxes = $149 million

[17] Transportation & Handling = $869 million, Retail Margin = $102 million and Retail Taxes = $314 million

Propane Industry Employment

Information regarding employment levels in the propane industry in Canada is limited. Statistics Canada provides some data regarding employment in various sectors of the economy. GPMi has utilized this information along with an assessment of the proportion of the propane industry to the total petroleum industry to estimate total direct employment in the propane industry in Canada. The employment breakdown by sector for Ontario in 2015 is shown below along with a brief description of the employment categories:

- Service stations/Distribution Facilities – 377
  - Comprises employees in companies primarily engaged in retailing motor fuels. It includes head office and administrative staff.
- Oil and gas extraction – 16
  - Comprises employees in companies primarily engaged in operating oil and gas production operations, both field and head office staff. This category includes staff working in natural gas and NGL processing facilities.
- Petroleum product manufacturing – 186
  - Comprises employees in companies primarily engaged in refining crude petroleum.
- Petroleum product merchant services – 410
  - Comprises employees in companies primarily engaged in wholesaling, retailing and delivery (excluding service stations) of refined petroleum products including liquefied petroleum gases. This category includes employees involved in the transportation of LPGs.
- Support activities for oil and gas extraction – 232
  - Comprises employees in companies primarily engaged in providing support services for the extraction of oil and gas.

Direct employment in the Ontario propane industry is estimated to be 1,220 persons in 2015. GPMi estimates an overall employment multiplier of 2.45. Therefore, total direct and indirect employment in the propane industry in Ontario is approximately 2,990 jobs in 2015. The Petroleum Human Resources Council of Canada[18] indicates an indirect multiplier for the petroleum industry of between 3 and 5 which would imply total direct and indirect employment in the propane industry in the 3,660 to 6,100 range. The Council also expects a growth in total direct employment in the petroleum industry of between 64% and 77% above current levels over the next decade. Using similar ratios would imply that direct employment in the propane industry in Ontario could grow to between 2,000 and 2,160 by 2022.

[18] The Decade Ahead: Labour Market Outlook to 2022 for Canada's Oil & Gas Industry, May 2013

The factors creating a relatively robust outlook for the propane industry include growth of supply from rich gas developments to feed LNG demand as well as growth of demand due to competitive prices compared to alternate fuels.

Economic Harm

In IR responses, Union provides a copy of a study by ICF International (ICF) which was completed for the Canadian Gas Association[19]. The ICF study discusses the economic benefits of switching to natural gas for space and water heating. ICF points out that "The primary driver of overall economic benefits is the re-spending of customer fuel cost savings, which is calculated by comparing fuel price forecasts. However, it is important to consider all macro- economic implications, as natural gas conversions will lower domestic consumption of some other fuels, and hence have negative economic impacts in some areas."[20] GPMi concurs with ICF on this issue. However, when it comes to actually applying this principal in their analysis, GPMi contends that ICF assumes too low an impact to the propane business especially for the type and location of expansion proposed by Union. As discussed below, the customer fuel cost savings are more than offset by losses of existing customers if they are forced to finance uneconomic expansions. In addition, the added rate base ensures that utility shareholder returns continue to be paid by the existing and new customers in these situations.

ICF argues[21] that the substitution of natural gas for other fuels won't have a large impact (they assume 15% of original costs) because those other fuels will continue to be produced and will be sold into other markets. They also assume that any job losses will be offset by increased transportation costs and jobs to deliver those fuels to alternate markets. That argument may have some validity in a national scale but on a local scale, especially in an area like Southern Ontario, it is demonstrably not true.

In the case of Southern Ontario, there really are no other markets for the other fuel distributors to pursue. All markets that are within a reasonable distance from the proposed project areas are already adequately served with fuel supplies. So, for the fuel suppliers in the areas Union is targeting, the losses they see when consumers convert are permanent losses. They cannot be replaced. As pointed out above, the retail component is the largest economic contributor to the propane value chain in Canada in general and Ontario in particular. The losses are real and substantial.

A related impact that is often overlooked in this type of situation is the indirect damage or unintended consequences of the expansion. For example, if

[19] Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B, CCC.5, "Economic and Emissions Benefits of Expanding Natural Gas Distribution Pipelines to Canadian Consumers", ICF International, November 2015

[20] Ibid., page 6

[21] Ibid., Appendix pages A-7 & A-8

expansion of natural gas distribution displaces propane in a community, then the propane service for surrounding communities is also affected. The cost to serve those nearby communities goes up because the propane distributor has to recover the same costs from a smaller volume. Propane trucks drive more or less the same distance to distribute a smaller volume. The end result is that the nearby customer pays more to receive propane. If the distribution to a particular area is marginally economic to begin with, then there is the very real possibility that those nearby customers would lose propane service altogether[22]. The economic loses are more than the direct losses described above. There is an economic loss multiplier effect that must also be taken into account.

The original statement that ICF makes is correct. You must take into account the impacts on other fuel supplies. The argument that the other fuels would be sold elsewhere is really a two-way street. The same thing can be said of natural gas. If it is not sold to residential consumers, then it will be sold into another market. You cannot claim full benefits for one and only partial losses for the other. If there is no alternative market for the displaced fuel and the cost of the fuel replaced is greater than the new fuel, then the economic loss is greater than the gain. However, this does not mean that there are no economic gains from substituting a lower cost fuel for a higher cost one or that consumers should not seek to lower their fuel costs. It depends on how the substitution is financed.

ICF and Union argue that the construction of new gas distribution systems provides a large benefit because of the large amount of money spent and construction jobs created. But Union's proposed projects are really just replacing an existing system, which by definition is a maintenance cost and which does not stimulate new production. This is an example of the "Broken Window Fallacy"[23]. An economy doesn't grow by deliberate destruction of existing systems because the investment required to replace those destroyed systems could be used to purchase other truly incremental goods and services. An economy does grow if the existing systems are replaced by fair competition on a level playing field and if the new investments are economic. In this case, the playing field is far from level and the proposed projects are far from being economic on any realistic measure. Propane and heating oil suppliers compete in a free market with other energy suppliers and with each other, and they do not have monopoly power over their customers. They do not have the luxury of large rate bases with guaranteed returns or large existing customer bases who can be forced to cross subsidize new expansions through higher rates. They do not have the ability or means to artificially underprice their service.

[22] Furthermore, if those nearby customers are unfortunate enough to live in a rural area on the Canadian Shield where it is very expensive to lay small diameter pipe, then they face the prospect of very high fuel costs or of losing all fuel service.

[23] Breaking windows does provide work for glaziers but the overall economy loses because the cost to replace the windows reduces the window owner's disposable income which could have been spent on truly incremental goods and services.

An economy also doesn't grow by subsidizing uneconomic projects, which by definition are any projects with a Profitability Index (PI) of less than 1. Nevertheless, there are situations where the desire for intangible benefits may drive a decision to invest in a project with a profitability index of less than 1. It is difficult to determine an absolute limit for these situations because the value intangible benefits are often based on judgment. However, projects with a profitability index less than 0.8 or 0.9 are clearly destructive in an economic sense.

Natural Gas Distribution Systems Expansion

The decision to expand natural gas service turns not on the relative cost of the natural gas itself but upon whether the delivery charges imposed by the utility over a number of years will recover the costs of the infrastructure built to deliver it. In some form or another, this analysis is done by every utility contemplating an expansion and by the regulator that supervises the utility.

Natural gas utilities certainly have the ability to expand their natural gas systems to suburban and rural areas where there are currently propane, heating oil and electricity customers. But they do so when anticipated revenues from the service cover the anticipated costs, including a profit for shareholders. Like any business, if it is cost effective for them and their shareholders to expand, then they should do so. However, when it is not cost effective to do something, they should not be petitioning government to sanction taxpayers or captive customers to foot the bill for an uneconomic investment. Natural gas utilities making expansion proposals that require cross-subsidization are not putting their shareholders' capital at risk[24]. When a utility asks for authorization to surcharge the utility's existing captive customers in order to fund the uneconomic expansion, the utility is really asking to transfer what should be its shareholder risk to its existing and future captive customers.

Economic efficiency usually requires that those receiving a service should pay for it. This is a principle grounded in fairness to all classes of energy consumers so that one class does not subsidize another. This principle is also based on allocating resources efficiently. If new customers of natural gas are subsidized by existing customers of natural gas, new customers receive their service at prices less than the cost of providing it. The incorrect price signals lead to an over allocation of resources when compared to free market competition because the product is underpriced. The result is that society's resources are allocated in a suboptimal manner. This happens when resources are deployed for projects that are uneconomic.

A further issue that is often overlooked in the debate over expanding natural gas distribution systems is the "Do Nothing" option. If the proposed expansion is uneconomic (i.e., PI < 1), then not expanding means that existing

[24] In fact, Union claims that it should not be exposed to financial risk in Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B.CPA.11 (b)

utility customers' disposable income is not decreased because they are not forced to pay a surcharge or subsidy. Furthermore, the existing rate base and existing customer charges will decline[25] with the result that the existing utility customers' disposable incomes will increase. Utility shareholders will not lose. They simply will not receive monopoly returns and will be forced to seek other, presumably economic, investments for their capital.

In summary, subsidizing uneconomic natural gas systems expansions has several negative consequences, including:

- Masking the real costs of expansion
- Overbuilding facilities and inefficient investment
- Artificially increasing demand for the service
- Unfairly burdening existing customers that receive minimal benefit
- Amounts to subsidies for utility shareholders
- Permits utilities to leverage their monopoly franchises, and captive customers, against other market competitors
- Creates below-market rates that unfairly compete with other energy suppliers, and
- Stifles free-market competition among energy suppliers.

Green House Gas (GHG) Emissions

In an IR response[26], Union suggests that propane produces more emissions than natural gas. GPMi submits that there is much more to the emissions story than Union suggests. Propane shares the clean emissions profile of natural gas. Propane is cleaner than fuel oil and much cleaner than electricity generated with either coal or natural gas. Natural gas system extensions that rely upon possible emissions gains to justify imposing facility expansion costs upon existing captive natural gas customers cannot be justified where propane is available as an alternative. On a full-fuel-cycle basis, both propane and natural gas are much more desirable than electricity generated from fossil fuels from both an efficiency and emissions point of view. Unlike propane, natural gas is a potent greenhouse gas if it leaks into the atmosphere. Propane and natural gas are chemically similar, and they share similar emissions profiles in terms of both pollutants (NOx, SOx, CO, mercury, and particulate matter) and greenhouse gases (CO2). Natural gas (methane) generates fewer greenhouse gas emissions per unit of energy consumed than propane. From a greenhouse gas perspective, however, the two commodities differ markedly in that natural gas emitted into the atmosphere in its raw form is a potent greenhouse gas—at least twenty-five times as potent as CO2. In contrast, propane in its raw form is not a greenhouse gas due to its short lifetime in the atmosphere. Natural gas and

[25] Due to ongoing depreciation of the existing rate base.

[26] Community Expansion Interrogatory Responses, 2015-12-9, Exhibit B.CPA.4

propane can fuel the same customer applications and they both do so in a relatively environmentally benign fashion.

The Propane Education and Research Council (PERC) has completed a thorough analysis of GHG emissions from propane and other fuels in the most common applications including residential space and water heating as well as a variety of transportation and other applications[27]. The analysis uses up to date data regarding energy consumption rates, emissions factors, and equipment efficiencies to estimate greenhouse gas emissions associated with the use of various energy options in a range of residential and commercial, on-road, off-road and agriculture applications. Actual life-cycle emissions levels depend on the nature and efficiency of the end-use application and therefore must be estimated on an application-specific basis.

PERC reports that when comparing systems for space heating, the difference in GHG emission reductions between natural gas and propane is less than 1%. For water heating the difference is about 14%[28]. The PERC study shows that there isn't a material incremental benefit, from a GHG emissions perspective, of choosing natural gas over propane when switching from either furnace oil or electricity. In fact, switching every furnace oil and electricity consumer to propane would get better than 90% of the GHG emission reductions for only the in home conversion costs. In other words, none of the many millions of dollars that would be required to expand natural gas distribution systems would need to be spent. GPMi submits that converting to propane would be a much more effective use of Ontario's economic resources.

Direct Harm to the Propane Industry

GPMi estimates that roughly 80% of the propane business in Ontario is in areas where natural gas utilities could consider expanding if the economic criteria suggested by Union in their Community Expansion Application were to be approved. It would take a number of years for expansions to occur and for the full impact of those expansions to be realized.

If such expansions are undertaken, they will remain uneconomic for the reasons outlined above. However, due to the volatility of energy prices, at some point in the future, the free option to convert[29] will be in the money, even if only briefly, and a number of customers will exercise their option. GPMi assumes that up to 50% of existing propane residential and commercial consumers would eventually convert along with some agricultural, manufacturing and construction customers. As a result, up to 25% of the economic value associated with the

[27] Propane Reduces Greenhouse Gas Emissions: A Comparative Analysis, Propane Education & Research Council, 2009

[28] It should be noted that the PERC report is for U.S. locations which are somewhat warmer and therefore have lower overall fuel consumption. Also, water heating is about 23% of the total load in the PERC study but will be somewhat lower in Canada. Those issues don't make a material difference to the comparisons.

[29] As described in the discussion of Relative Fuel Prices in Section II

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propane business in Ontario will eventually be lost. This translates into $133 million of direct economic value (2015 dollars) and $321 million of total direct and indirect economic value that will eventually be lost.

In terms of jobs, GPMi assumes approximately 40% of jobs in petroleum product merchant services (164), 20% of jobs in service stations/distribution facilities (75) and 20% of jobs in petroleum product manufacturing (37) for a total of 276 jobs would be lost.

The harm will be concentrated in the residential and commercial propane distribution business in Ontario and will undermine the viability of that business over the long term. As described previously, these losses are permanent.

IV Conclusions

Propane is a competitive fuel in Ontario. However, Union has argued that there is a potential cost saving to be realized by customers who convert to natural gas service. GPMi has demonstrated that Union's estimates of cost savings are too high. The pay back period for converting is greater than 7 years and consequently few customers will convert, especially in the early years after natural gas service is made available. Union's proposed expansions are not economically feasible even with Union's overly optimistic assumptions. Union's ratepayers and not its shareholders will bear the cost of these uneconomic projects.

If natural gas systems are expanded, the potential new customers are given a free option (financed by existing customers) to convert when prices are favourable. Few conversions will occur initially but sooner or later favourable conditions will arise and customers will begin to convert. From that point on, GPMi estimates that up to 25% of the economic value and jobs generated by the propane industry will be permanently lost.

Propane distributors operate in open and competitive markets. Natural gas utilities in Ontario do not. The cross-subsidization used by utilities to underpin expansions of their natural gas systems undermines the long term viability of the residential and commercial propane distribution business in Ontario.

Propane has numerous advantages for residential and commercial customers including:

- Propane does not require multi-million dollar infrastructure that must be paid for by consumers over decades.
- Propane does not require complex decisions by regulators as to who should pay for new energy infrastructure.
- Propane infrastructure is funded by the propane industry, not by new or existing ratepayers.
- Propane infrastructure does not require a multi-decade (essentially forever) commitment by ratepayers and regulators.
- Propane is produced and delivered in fully competitive markets that do not require the investment of regulatory resources.
- Propane has comparable GHG emissions to natural gas.
- Propane customers can switch to other sources of energy at any time without requiring other energy consumers to pay for infrastructure that was built for them.

All of these advantages are lost when uneconomic gas distribution expansions are allowed to proceed.

Appendix

Curriculum Vitae – Gerald Goobie, P.Eng.

An oil and gas professional with 28 years of commercial operations, business development and natural gas, natural gas liquids (NGL) and crude oil marketing as well as 7 years of technical engineering experience

CAREER SYNOPSIS

Currently Principal, Gas Processing Management Inc., providing natural gas processing, NGL and petrochemical feedstock consulting services.

8.5 years Managing Consultant, Purvin & Gertz, Inc. providing NGL, natural gas and crude oil consulting services.

24 years various commercial, operational and technical engineering positions

EDUCATION

Master of Business Administration, Finance Major, 1988
University of Calgary

Master of Science, Chemical Engineering, 1981
University of New Brunswick

Bachelor of Science, Chemistry, 1976
Memorial University of Newfoundland

Registered Professional Engineer in Alberta

REPRESENTATIVE MAJOR PROJECT EXPERIENCE

- **REGULATORY PROCEEDINGS –**

  Provided Canadian Propane Supply and Demand Outlooks for two long term propane export applications to the National Energy Board of Canada.

  Provided an evaluation of Bakken area NGL supply and Western Canadian ethane demand in support of an ethane pipeline which delivers specification ethane to Alberta from North Dakota.

Provided expert advice regarding natural gas supply issues, economic efficiency and plant operating issues related to a proposed "sidestreaming" project in Central Alberta. Further work included analysis of proposed changes to the TransCanada PipeLines intra-Alberta system to accommodate producers' access to NGLs in the common stream.

For the 2007/2008 Alberta Energy and Utilities Board omnibus NGL Inquiry, provided expert evidence regarding the Alberta NGL Extraction Convention, reviews of sidestreaming and co-streaming projects and an evaluation of the NGTL North Central Corridor natural gas pipeline project.

- **PROPANE MARKET STUDIES –** Provided a series of in depth evaluations of the Canadian propane market for the Canadian Propane Association.
- **PETROCHEMICAL FEEDSTOCK REVIEW –** Provided a comprehensive review of Western Canadian petrochemical feedstocks for the Government of Alberta including conventional gas based feedstocks as well as upgrader offgas and synthesis gas supplies.
- **WATERBORNE NGL EXPORT TERMINAL REVIEW –** Provided a comprehensive review of North American NGL export terminals including capacities, expansion plans and opportunities as well as supply and export availability for a large international NGL trading company. Provided a similar analysis for a large Asian NGL supplier focused on Western Canadian supply availability for a proposed west coast NGL export terminal project.
- **FACILITY AUDIT –** For an international petrochemical company managed a major joint venture audit of a fractionation and storage facility. The audit included an analysis of storage gains and losses, product allocation procedures, development of a new allocation program and a determination of required facility metering upgrades.
- **SUPPLY, DEMAND AND PRICING –** Solely responsible for Canadian natural gas and NGL supply, demand and pricing outlooks. Member of team responsible for North American crude oil supply, demand and pricing outlooks.
- **OILFIELD SERVICES REVIEW** – For an international client provided a market overview of the oilfield services business in Western Canada including an outlook for nitrogen demand.
- **CONSTRUCTION REVIEW –** Performed an independent engineer due diligence review of a pipeline construction project for a major bank which provided project financing.

- **INSURANCE VALUATION –** Provided replacement cost valuations of several large sour gas processing facilities in Western Canada including gas sweetening, and gas compression.
- **ROYALTY POLICY -** Performed an analysis of the Alberta Natural Gas and NGL Royalty system and its impact on ethane prices in Alberta. Provided assistance to the Alberta Department of Energy to create and implement the Incremental Ethane Extraction Program (IEEP) to encourage development of incremental sources of petrochemical feedstocks in the province. The engagement included development of a detailed Western Canadian ethane supply and demand forecast for the Ethane Consumption Baseline (ECB) which is used to determine eligibility of ethane production projects for an ethane royalty credit under the IEEP policy.
- **VALUE ADD** - Performed several economic value added analyses of Canadian ethane, propane and butane markets.
- **NATURAL GAS PIPELINE ANALYSES -** Performed several analyses of natural gas markets and flow forecasts for major natural gas pipeline systems in North America.
- **NATURAL GAS PIPELINE ANALYSES –** for a large natural gas export pipeline owner provided an evaluation and outlook for commercial viability of the pipeline.
- **GAS MARKETING/GAS PROCESSING –** Negotiated numerous natural gas transportation, processing and sale agreements with producers, shippers and processors in Western Canada. Was responsible for processing agreements in British Columbia, Alberta and Saskatchewan as well as transportation contracts on the Westcoast (Spectra), NGTL, TransCanada and ATCO Pipelines systems.
- **NGL PRODUCT SALE RENEGOTIATIONS –** Was responsible for renegotiation of existing propane plus and ethane sale arrangements at several straddle plants including changes to price, term and volume.
- **NGL EXTRACTION PLANT DUE DILIGENCE –** for a Canadian Midstream consortium provided due diligence assistance related to the potential acquisition of a group of NGL straddle plants. Assistance included an analysis of natural gas feedstock supply and NGL and ethane product sales agreements.
- **NGL BUSINESS DUE DILIGENCE –** for a Canadian Midstream company provided due diligence assistance related to the potential acquisition of an integrated North American NGL production and marketing business. Assistance included an analysis of natural gas feedstock supply, facility operating agreements, NGL and ethane

product sales agreements, storage agreements and financial analysis of the business.

- **NGL BUSINESS DIVESTMENT –** for a Canadian Midstream company provided assistance related to the disposition of an integrated North American NGL production, fractionation, storage and marketing business. Assistance included an analysis of North American natural gas markets, natural gas feedstock supply and NGL Markets.
- **DIVESTMENTS -** For an international petrochemical company, provided a commercial evaluation of an underground natural gas and NGL storage facility in Canada, as well as a market study of North American natural gas and NGL underground storage.
- **DIVESTMENTS –** For a major international producer, provided assistance in the divestment of a minority interest in an operated intra-Alberta straddle plant. This task included development confidential information, organizing a data room, analyzing bids and managing regulatory filings. Further work included assistance in the divestment of a minority interest in an operated intra-Alberta ethane pipeline. This task included development of a confidential information memorandum and organizing a data room.
- **ARCTIC GAS –** for several industry participants, performed various analyses of the impacts of Mackenzie and Alaska gas on North American natural gas and NGL supply, demand and markets.
- **LITIGATION –** Provided expert testimony in a Business Interruption insurance claim dispute.
- **LITIGATION –** For a major Canadian midstream operator provided expert testimony in a gas supply contractual dispute.
- **DILUENT OUTLOOK –** For a Canadian Midstream company provided strategy development assistance regarding the development of a condensate diluent supply business for heavy oil markets in Western Canada.
- **COMMERCIAL ADVICE:**
  - For an international client, assisted in the negotiation of long term NGL purchase contracts.
  - For an integrated oil company, performed an economic evaluation of its Canadian NGL business
  - For a government department, provided an evaluation of current and future ethane supply and demand in Western Canada

- For an international producer, provided commercial advice regarding the potential divestment of a minority share in a straddle plant
- Provided several analyses of ethane supply costs from existing and potential deepcut projects at gas plants in Western Canada
- Provided a review of value for olefinic NGL production from a proposed bitumen upgrader
- Provided an analysis of LNG imports and LPG pricing into Eastern Canada
- Provided an analysis of feedstock economics for an Eastern Canadian petrochemical producer
- For an international chemical company, provided advice on the acquisition of a crude oil blending terminal in Alberta
- For a large gas aggregator, provided advice on contract terms for a straddle plant processing agreement
- For an international integrated oil company, provided an analysis of transfer pricing among divisions

• **CONFERENCE PRESENTATIONS** – Mr. Goobie is a frequent speaker at numerous crude oil, natural gas, midstream and petrochemical conferences.

FORM A

Proceeding: EB-2016-0004

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Gerald Goobie. I live at Calgary, in the province of Alberta .

2. I have been engaged by or on behalf of The Canadian Propane association to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: March 3, 2016

Signature

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

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AFFIDAVIT OF ANDREA LABELLE
(sworn March 3, 2016)

I, Andrea Labelle, of the City of Ottawa, Province of Ontario, MAKE OATH AND SAY:

1. I am the Executive Director of the Canadian Propane Association, an industry association which represents the propane industry. As such, I have knowledge of the matters to which I hereinafter depose. Where my knowledge is based on information and belief, I state the source of my belief and verily believe it to be true.

2. In connection with this proceeding, I obtained estimates of the cost of converting household appliances from propane to natural gas from two heating and air conditioning companies. I verily believe them to be true. Attached as **Exhibit "A"** is a copy of the estimate from Brian Cowan's Heating & Air Conditioning Services. Attached as **Exhibit "B"** is a copy of the estimate from Coad Plumbing, Heating & Air.

3. I have reviewed the affidavit of Gary Highfield, Director of Propane, Parkland Fuel Corporation ("**Parkland**"), an Intervenor in these proceedings. The portions of Mr. Highfield's affidavit relating to existing competition for fuel in rural Ontario and impacts to Parkland of subsidized natural gas expansion are true for Parkland and are generally true for other propane industry participants in Ontario.

SWORN BEFORE ME at the City of Toronto,
this 3rd day of March, 2016.

A Commissioner for taking Affidavits *(or as may be)*

Andrea Labelle

This is Exhibit "A" referred to in the affidavit of

.....ANDREA LABELLE.....

sworn before me this 3rd day of March, 2016

A Commissioner, etc.

Brian Cowan's
Heating &
Air Conditioning Services

Box 139, Sparta, ON N0L 2H0
Phone: 519-775-2679
Fax: 519-775-2840

Propane to Natural Gas Conversion cost Feb. 25, 2016

Forced Air Furnaces & Hot Water Boilers

Total **$650.00 - $850.00** plus applicable taxes

* Conversion kits may not be available from the manufacturer, thus a complete replacement would be required

Domestic Tank Water Heaters

Cost to remove and install a new N.G. unit would be **$1695.00 - $2300.00**

Water heaters cannot be field converted
Rental of Water heater may be considered.

Other household appliances

Clothes dryers, Fireplace's, Kitchen range etc.

NG conversion Kit cost (if available)
Labour to perform the conversion (2.0 hrs avg.)

Per appliance,

Total **$475.00 - $700.00**

Brian Cowan,
Brian Cowan Heating and Air Conditioning

This is Exhibit "B" referred to in the affidavit of

.....ANDREA LABELLE.....

sworn before me this 3rd day of March, 2016

A Commissioner, etc.

519-633-4256
www.coadheating.com
43993 Talbot Line, St. Thomas, ON N5P 3S7

COAD
PLUMBING HEATING AIR

PREMIER
LENNOX

Cost of converting an average home in Southwestern Ontario from Propane to Natural Gas

The following prices stated below are typical expenses of the conversion of household's appliance's from Propane to Natural Gas.

A) High and Mid Efficiency Forced Air Furnaces & Hot Water Boilers

NG conversion Kit cost (if available)	$350.00 - $450.00
Labour to perform the conversion (3 hrs avg.)	$375.00 - $450.00
Total	**$725.00 - $900.00**

*Note,
i) In some cases conversion kits may not be available from the manufacturer.
ii) Older appliances (+15 yrs.) would be recommended to be replaced.

B) Domestic Tank less and Tank type Water Heaters

Very seldom these types of appliances can be converted from Propane to N.G.
A total replacement would have to be performed.

Typical replacement cost would be **$1800.00 - $2200.00**

*Note,
Rental of Water heater may be an option.

C) Gas fired Fireplace's

NG conversion Kit cost (if available)	$350.00 - $450.00
Labour to perform the conversion (2.0 hrs avg.)	$200.00 - $300.00
Total	**$550.00 - $750.00**

*Note,
i) In some cases conversion kits may not be available from the manufacturer.
ii) Older appliances (+15 yrs.) would be recommended to be replaced.

Cont.....

519-633-4256
www.coadheating.com
43993 Talbot Line, St. Thomas, ON N5P 3S7

COAD
PLUMBING HEATING AIR

PREMIER DEALER
LENNOX

D) Kitchen Ranges, Stove Tops and Stand-alone Ovens

NG conversion Kit cost (if available)	$350.00 - $450.00
Labour to perform the conversion (2.0 hrs avg.)	$200.00 - $300.00
Total	**$550.00 - $750.00**

*Note,
i) In some cases conversion kits may not be available from the manufacturer.
ii) Older appliances (+15 yrs.) would be recommended to be replaced.

E) Domestic Clothes Dryers

NG conversion Kit cost (if available)	$350.00 - $450.00
Labour to perform the conversion (2.0 hrs avg.)	$200.00 - $300.00
Total	**$550.00 - $750.00**

*Note,
i) In some cases conversion kits may not be available from the manufacturer.
ii) Older appliances (+15 yrs.) would be recommended to be replaced.

Savings could be achieved if more than one appliance gets converted at the same residence on the same day.

Regards,
Steve Coad

President,
Coad Plumbing, Heating & Air