EXPANSION OF NATURAL GAS DISTRIBUTION IN SOUTHERN BRUCE COUNTY

THE BUSINESS CASE

October 6, 2014

J. Mark Rodger
Co-Chair, Energy Markets Group
Borden Ladner Gervais LLP
416-367-6190
mrodger@blg.com
Scotia Plaza, 40 King St W
Toronto ON, Canada M5H 3Y4
T

Prepared by:

Borden Ladner Gervais

Henley International Inc.
Elenchus Research Associates Inc.
Innovative Research Inc.

Table of Contents

Executive Summary

The municipalities of Arran-Elderslie, Kincardine and Huron-Kinloss (the "Municipalities" or "South Bruce") do not have access to natural gas distribution. This is a serious disadvantage for residents and businesses in these communities. Over the past two years the Municipalities have received two proposals to solve this problem. The two options are very different and reflect very different costs, risk profiles and end user rates for natural gas distribution services. One proposal is from Union Gas Limited ("UNION") and the other proposal is from Northern Cross Energy Ltd. ("NORTHERN").

The purpose of this report is to assess the technical and economic feasibility of both proposals in light of existing Ontario regulatory requirements and recent customer survey and load forecast (demand) information. The report describes the central considerations and risks associated with both options and identifies critical areas where further information is required in order for the Municipalities to make an informed decision on the preferred course of action to bring natural gas distribution to the area.

A key conclusion made in this report is that financial assistance and/or changes to existing regulatory requirements are likely needed from both the Province of Ontario and the Government of Canada.

For the first time in one document, this report brings together and provides an assessment of the various critical considerations that the Municipalities must evaluate and manage in determining whether natural gas distribution is a viable option for their area. The report can also be seen as a roadmap for the next steps that should be taken to further the due diligence review surrounding this entire initiative.

In March of 2012 UNION provided a proposal to supply natural gas to South Bruce. The proposal recommended the extension of UNION's facilities from the north via a connection to its existing system near Dornoch and from the south via a connection at Wingham.

UNION estimated the demand for natural gas in the area by means of a survey of the customer groups (residential, commercial and industrial) and its experience with similar extensions in other areas. It estimated that the total demand for natural gas would be approximately 30 million cubic meters annually with about half of this accounted for by industrial demand, 30% by residential demand and 20% by commercial demand.

Given existing regulatory requirements, the rates to be charged by UNION for this proposed system expansion would have to be the same rates it charges to other customers in its southwestern region. To avoid cross subsidization by other consumers incremental costs must be met through what is referred to as "contributions in-aid of construction" (that is, a cash payment from the Municipalities to UNION). UNION estimates that the capital expenditures for the project would be close to $97 million and that the resultant required contribution in aid-of-construction paid by the Municipalities would be just under $86 million (based on forecast 2012 costs).

As noted, this amount would have to be paid by the Municipalities and/or possibly other levels of government. Independent analysis of the UNION proposal prepared by AMEC/EFG consultants indicated that it was technically feasible and confirmed that that capital expenditure estimate was reasonable but could be subject to up to a 20% error. It also concluded that while the proposal was feasible it was not practical because of the high capital cost relative to the customer base and the resultant high landed cost of natural gas.

NORTHERN has recommended a different approach which would involve the formation of a new, stand-alone gas distributor owned by the Municipalities. Under this approach the cost of the project would be passed on to consumers. The demand estimates used by NORTHERN were based on those used by UNION with modifications made by NORTHERN in the areas of demand by grain driers and industrial demand and the inclusion of the Township of Ashfield-Colborne-Wawanosh. Overall NORTHERN's total demand was some 25% higher than UNION's due to differences in the two areas just mentioned.

The development of the new natural gas delivery system would consist of three phases with total capital expenditures amounting to $70.2 million, substantially less than the UNION proposal. This phased approach follows for the flexibility to connect high-demand industrial and commercial customers early on to maximize load in the primary stages of the project's development. Financial projections using these estimates along with other assumptions showed that rates charged to consumers would be substantially higher than those charged by UNION or NRG, another natural gas distribution company of similar size and location to that being proposed for South Bruce. Notwithstanding these rates consumers could realize savings over existing costs using alternative fuels such as electricity, oil or propane.

However, the NORTHERN option involves a number of risks which require further analysis and review to better understand the extent of these risks. First is the risk related to the demand forecasts. An update of the demand projections was prepared by Innovative Research Group and Elenchus which show significant differences from the forecasts used by UNION and NORTHERN. The actual conversion behavior of consumers when confronted with conversion costs and actual natural gas rates could be different than anticipated. Secondly, the technical features of the NORTHERN proposed system require additional in-depth independent analysis given the information available at this time. A preliminary technical risk review undertaken by DR Quinn and Associates Inc. identified a number of areas requiring closer examination. This is not to suggest that the technical features of the NORTHERN proposal are less developed than Union's but rather that there was not sufficient time to undertake a thorough analysis of them. Thirdly, the capital expenditure estimate provided by UNION is dated and requires an update and that provided by NORTHERN requires independent verification. Even so both estimates are subject to error.

These risks could be mitigated by the provision of funds or other assistance by other levels of government. For example, the Province of Ontario has indicated its commitment to the expansion of the natural gas distribution network in the province.

This report is the result of a collaborative approach taken between the Municipality of Kincardine, the Municipality of Arran-Elderslie, the Township of Huron-Kinloss and its external legal and consulting team comprising Borden Ladner Gervais LLP, Henley International Inc., Innovative Research Inc., Elenchus Inc. and DR Quinn & Associates Inc.

This report follows privileged legal advice provided by Borden Ladner Gervais LLP to the municipalities in February, 2014 relating to various legal, shareholder, corporate governance, and regulatory approval considerations that must be considered in establishing a jointly-owned natural gas distribution utility.

Recommendations

- The Municipalities should meet with senior provincial and federal government officials to determine what scope of assistance may be available and on what terms. Issues to be discussed includes both financial assistance and changes to existing regulatory requirements.

- With respect to the Province of Ontario specifically, the Municipalities should meet with the Premier's Office and Ministry of Energy to determine the applicability of recently articulated government policy around extending natural gas services to South Bruce.

- The Municipalities should begin discussions with Ontario Energy Board and TSSA officials to brief them on this report and to review and discuss the required regulatory approvals needed to implement the options under consideration..

- The Municipalities should continue their stakeholdering activities with the general public including all key customer groups and affected First Nations and Metis communities.

- UNION should be requested to update the cost estimates associated with its proposal. UNION should also be requested to re-evaluate its 2012 proposal in the context of current Ontario policy concerning extending natural gas services.

- NORTHERN should be requested to provide additional detailed cost and technical information so that the Municipalities can conduct further due diligence on the NORTHERN proposal. This may require that the Municipalities finalize and enter into the cost sharing agreement with NORTHERN based upon the draft agreement circulated by Borden Ladner Gervais in April, 2014.

- As part of the Municipalities ongoing due diligence review, consideration should be given to exploring potential public-private partnerships and/or contracting with third party service providers who would be capable of operating a natural gas distribution utility should the stand-alone option be selected as the preferred option.

Chapter 1: The Strategic Context

1.1 The Problem

The region of Bruce County comprising Kincardine, Huron-Kinloss and Arran-Elderslie (which will be called South Bruce in this report) is one of the few areas of Southern Ontario which does not have access to natural gas. Exhibits 1 and 2 show the areas serviced by UNION and Enbridge Inc. Notwithstanding the fact that natural gas is produced and stored just south of the region and natural gas pipelines from Western Canada pass by in close proximity towards the major population centres in Southern Ontario, the region remains an island, as shown as the white region on Lake Huron in Exhibit 1, not included in the southwestern Ontario natural gas network. This has had important economic consequences for the region. In the residential sector space and water heating costs are much higher than in other areas of the province reducing income available for expenditures in other areas and generally lowering the living standard of households in the area. In the commercial and industrial sectors it has raised operating costs creating a competitive disadvantage to doing business in the region.

Exhibit 1
UNION Gas Southwest Ontario Service Area

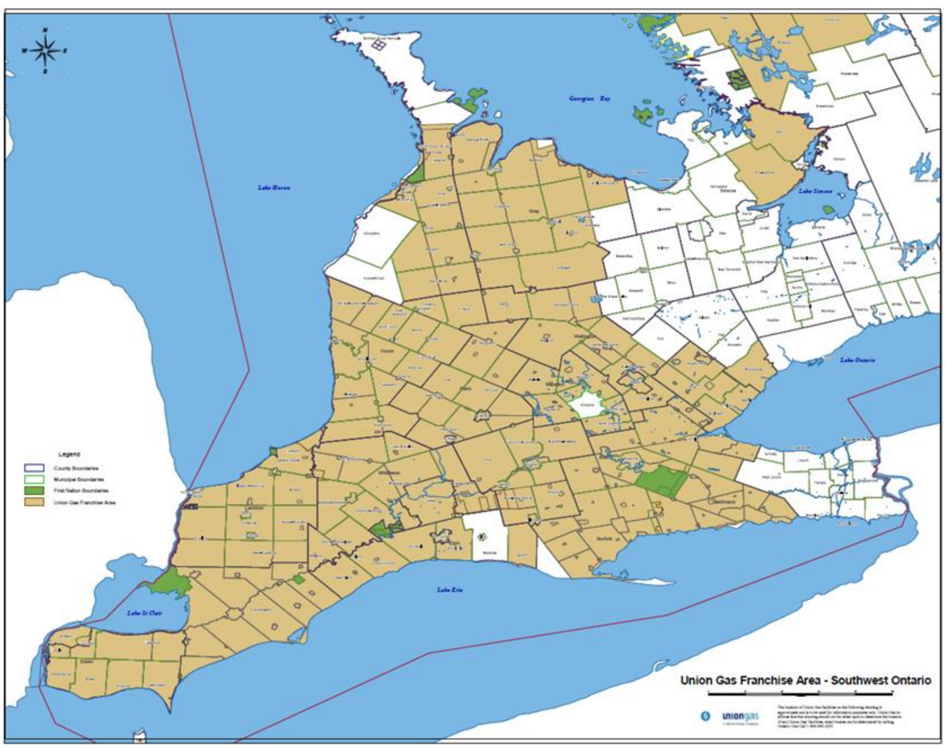
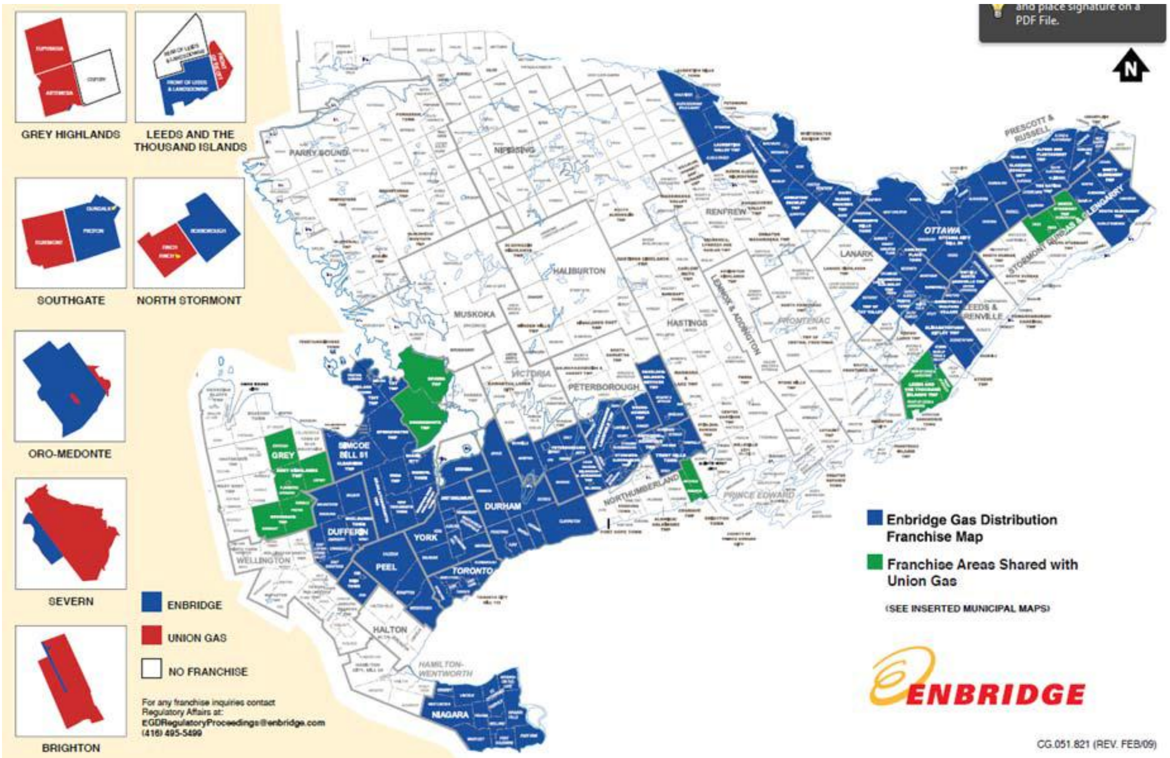


Exhibit 2
Enbridge Ontario Service Area

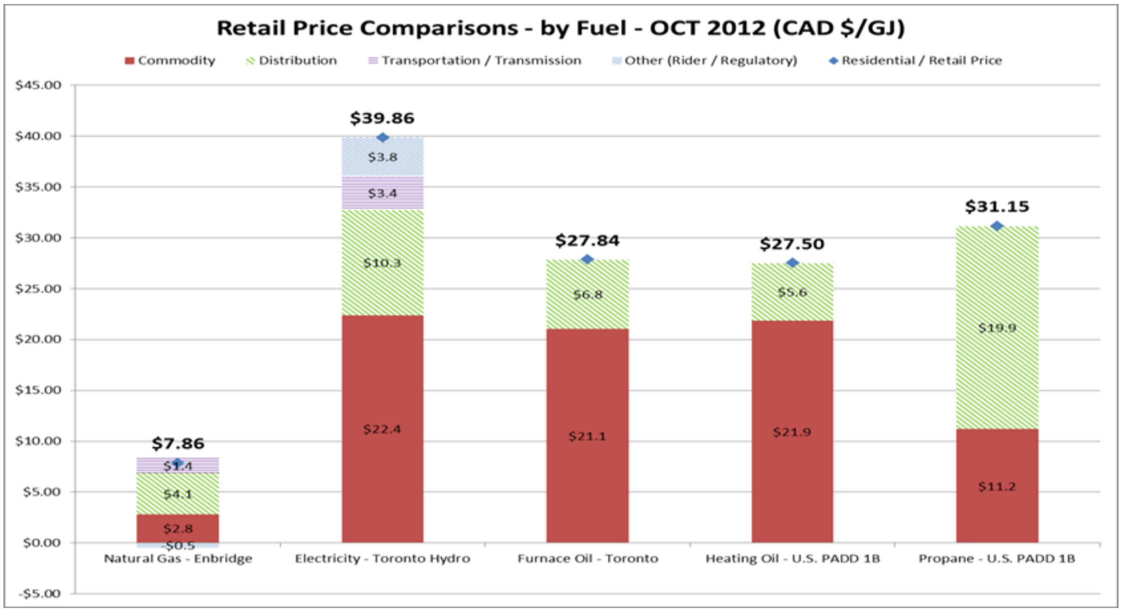


The size of the cost differential between natural gas and other fuel sources is not a minor issue. Exhibit 3 illustrates the differences in cost of alternative fuels both in Ontario and the Central Atlantic district of the U. S. prepared by the Ministry of Energy of Ontario. The comparison in Ontario is for Toronto but the results would be applicable to the Bruce County area as well. In each case the cost of alternative fuels is a multiple of the cost of natural gas with the largest difference in most cases due to the difference in the commodity cost of the fuel. In the case of propane delivery cost differences are also significant. It is evident that an expansion of the natural gas network into the area would eliminate a major disadvantage faced by area residents and allow commercial and industrial operations to compete on an equal footing to competitors in other parts of Canada and the U.S.

The issue of comparative costs will be revisited throughout the report.

Exhibit 3

Comparison of Fuel Costs



Source: Ministry of Energy Ontario, 2012.

1.2 South Bruce Requirements

The very high costs of heating using alternative sources of energy provides considerable room for the entry of a new natural gas supplier even at higher rates than in other parts of Ontario. Exhibit 4 illustrates the comparative costs of heating an average residential house using alternative fuels at current prices for these fuels. These represent the benchmarks that natural gas must meet in order to gain acceptance by consumers in the marketplace. The costs are calculated by taking the average annual residential consumption of natural gas as estimated by UNION and determining the energy equivalent required for each of the alternative fuels. This amount times the current prices of these alternatives gives an estimate of annual costs using these fuels. The chart shows that heating oil is the most expensive followed by electricity and propane. We will return to these estimates later in the report when the natural gas options are considered.

Similarly, the introduction of natural gas in the commercial and industrial sectors must meet the competitive tests of these markets. These will vary depending upon the nature of the commercial or industrial activity in each case and their specific energy requirements. In the case of the commercial market segment we again use UNION's estimates of the average annual consumption of natural gas by commercial customers but in this case UNION provides estimates for each of small, medium and large commercial entities, based on natural gas usage. Using current prices for alternative fuels yields the estimates shown in Exhibit 5.

Exhibit 4

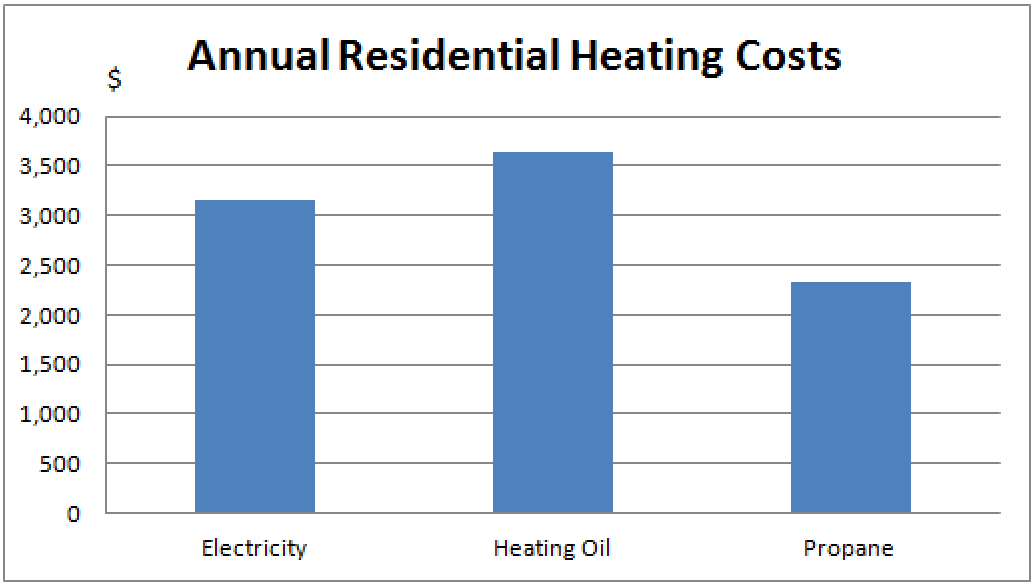
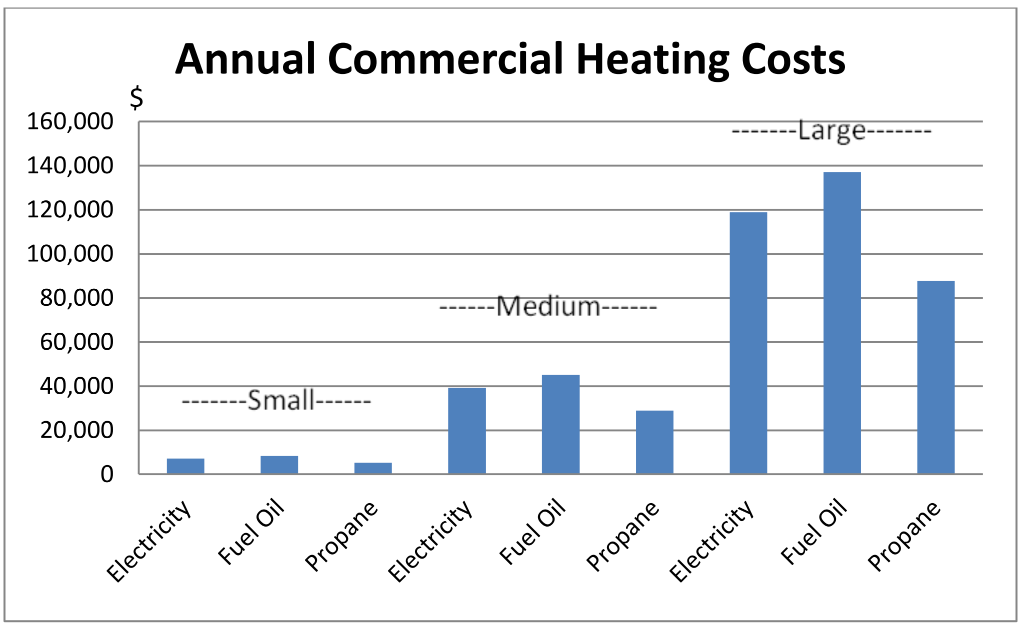


Exhibit 5



Any proposal to provide natural gas to the South Bruce area must be capable of meeting the market test of competitive fuels on terms that are acceptable to the sponsoring municipalities.

1.3 Assumptions, Constraints

This report considers two options for the provision of natural gas service to South Bruce. The first is a proposal by UNION to extend its system of natural gas transmission and distribution to include South Bruce. The second is a proposal by Northern Cross Energy (NORTHERN) for a stand-alone distribution company that would connect to its existing gathering and distribution system in Huron County. There are a number of critical assumptions that are fundamental to an economic assessment of these options, two of which dominate in importance: capital expenditures and projected demand for natural gas.

The geographical area under consideration is extensive involving over 500 square kilometers. The capital costs will include the costs of contractors, materials, engineering, right-of-way and other ancillary services for the installation of over 110 kilometers of gas mains and related distribution lines and equipment. The capital costs per unit of gas delivered are high compared to denser populations and will have a major bearing on the overall delivery costs (and ultimately whether the overall initiative is viable and sustainable). The capital cost assumptions made in the economic analysis here are those provided by each of the proponents. As we shall see there is a significant difference between two.

In the case of demand for natural gas the essential issue is the likely conversion of customers to natural gas from the fuel sources they are currently using. Potential natural gas customers face uncertainties both with respect to the future price of natural gas and the conversion cost from the existing energy source to natural gas. This varies significantly from one energy source to another. These costs can be a major impediment to conversion if the consumer faces the full conversion cost up front. It can be softened if the cost is distributed over time through an acceptable financing arrangement.

Conversion intentions of residential and commercial customers were estimated via a scientifically developed survey. The survey results were the basis for the development of demand forecasts. In the case of potential industrial customers they are sufficiently few in numbers that they were approached directly to assess the conditions under which they would switch at least some of their operations from existing energy sources to natural gas.

The demand projections obtained from this process are subsequently used as assumptions for the purpose of the economic analysis. Comparisons are also made to previous attempts at projecting the demand for natural gas in the area.

Several constraints are also critical to the analysis. First, the municipalities supporting the project must be capable of sourcing the financial capital that will be necessary to launch the new natural gas utility at acceptable rates. In an era of municipal financial stress this is not a minor consideration. Secondly, the project requires continued co-operation of these municipalities throughout at least the early years of operation of the project. The co-operation to date has been exemplary but councils can change and new information can create new concerns.

Another important concern is UNION’s capacity to deliver the required volumes at the identified connection points to the UNION system. The need for additional capital spending to relieve capacity constraints could be a significant impediment. Finally, there are a number of other assumptions such as operating costs, inflation, property taxes etc. that are a normal component of an economic evaluation.

Chapter 2: Option Review

2.1 Screening Criteria

The following broad criteria constitute the first level of screening of the options to be considered followed by a more detailed economic evaluation.

a) **Implementation Speed:** a priority will be given to options that can be put in place with little delay.

b) **Potential for Customer Cost Reduction**: only those options that can make a meaningful reduction in consumer energy costs will be considered.

c) **Municipal Financial Capacity**: options that require substantial municipal financial support will be considered to be not practical.

d) **UNION Gas Supply Capacity**: options must be capable of integration into the UNION network without creating major supply bottlenecks.

e) **Manageability:** must be within the capacity of the municipalities to manage ongoing operations.

f) **Risk Parameters:** options must be within acceptable levels of risk.

The review of options against these criteria is undertaken prior to the development of detailed option characteristics. The objective is to ensure that they pass feasibility and acceptability test at this high level before more in depth consideration is considered.

2.2 Option Description

This section will provide a high level outline of the major features of the two options under consideration. A more detailed examination of each is contained in later sections of the report.

2.2.1 The UNION Proposal

The March 2012 UNION report proposed an expansion of its existing system that would connect municipalities in the region at two connection points. The municipalities of Chesley, Paisley, Tiverton, Kincardine, Point Clarke and Inverhuron (North) would be connected to the UNION system near Dornoch and the municipalities of Ripley and Lucknow (South) at Wingham. In addition five industrial sites would also be connected. The North and South systems in the UNION proposal would not be interconnected.

Detailed projections of demand were prepared based on a survey undertaken by Ipsos-Reid which was intended to assess the potential of conversion of residential and commercial customers. Industrial customers were contacted individually to determine both their willingness to convert to natural gas and estimates of likely demand volumes. Demand projections for residential and commercial customers were based on the conversion estimates derived from the survey and UNION's experience with actual conversions in other areas and average consumption levels for typical residential and commercial customers.

An overall strong positive response was determined from the survey. Approximately 66% of households indicated they would convert to natural gas for their space and water heating needs and over 80% of commercial respondents planned to do so. Generally speaking about 80% of these said they would convert within two years.

Multiplying the conversion forecasts by average annual consumption levels provides a forecast of demand for natural gas by each of the customer classes. To this must be added the projected annual consumption levels of the industrial sector. The results showed that industrial demand would account for about half of total demand followed by residential at 30% and commercial at 20%.

The proposed UNION supply system consists of two natural gas transmission mains connected to the UNION network at Dornoch and Wingham and related distribution mains. The northern line is just under 80 km in length and connects Chesley, Paisley, Inverhuron, Tiverton, Kincardine and Point Clark. The southern line is just over 30 km in length and connects Lucknow and Ripley to UNION at Wingham. Lateral natural gas pipelines connect industrials along each of these lines.

Estimated capital expenditures for the northern line amount to $76 million and for the southern line to $21 million for a total construction cost of $97 million. This is split almost equally between natural gas distribution and transmission lines. Within the existing OEB regulatory framework, which will be discussed later in the report, UNION estimates that its share of these capital expenditures would be just over $10 million with the remaining $86 million to be paid directly by the municipalities in the form of Contributions-in-Aid-of-Construction (CIAC) payment to UNION.

UNION also raised the possibility that the system could be phased in over time. Recognizing the role played by industrial demand volumes it was suggested that industrial customers might be connected first followed by the municipalities. It provided a breakdown of capital expenditures related to industrials only to permit analysis of this alternative.

2.2.2 The Northern Cross Energy Proposal

NORTHERN has produced natural gas in Huron County since 1988 and currently delivers gas to the UNION system. It operates five natural gas production pools, 50 km of gathering and transmission pipelines as well as related gas compression and processing facilities. Its operation base is located southeast of Kincardine.

NORTHERN proposes to implement its development in three phases. The first phase would consist of an expansion of NORTHERN's existing pipelines to connect the municipalities of

Lucknow, Ripley and Point Clarke to the UNION system at Wingham. The second phase would connect the municipalities of Chesley, Paisley and Tiverton, as well as some industrial loads to the UNION system at Dornoch. Completion of distribution facilities in Ripley would also be accomplished in this phase. The third phase would link phases 1 and 2 at Kincardine, connecting the remaining municipalities.

The NORTHERN system would consist of over 200 km of natural gas mains in total and with related distribution lines and equipment the total capital cost is set at $70.2 million. NORTHERN projects the first phase could be in operation by as early as September 2015 serving Lucknow and Ripley and five of the six grain drier loads included in commercial demand. Phase 2 is projected to be in operation by September 2016 serving the northern municipalities and approximately half the projected industrial load. The final phase would enter into service in September of 2017 serving the remaining projected loads. It is proposed that the municipalities would acquire the distribution pipelines and compression stations from NORTHERN (in whole or in part), with NORTHERN maintaining ownership of the storage sites. The new gas distribution company would pay NORTHERN for gas storage.[1] There remain a number of legal, regulatory, technical, and financial issues that require further discussion and resolution requiring the NORTHERN proposal. In section 3.2.2 and Appendix C - we include preliminary technical analysis of the NORTHERN proposal prepared by DR Quinn & Associates Ltd.

The projected demand in the NORTHERN proposal is based largely on the UNION demand forecast, although NORTHERN's projected demand levels are higher than the UNION forecast volumes for all customer classes. Total demand is some 25% higher than UNION with the largest differences occurring in commercial and industrial. In the case of the commercial customer class NORTHERN makes specific allowance for the inclusion of six grain drying operations which account for about 30 % of commercial demand. Industrial demand is based on the identification of specific industrial customers and estimating their demand levels. .

Since the NORTHERN proposal calls for the creation and establishment of a new stand-alone, natural gas distribution utility (unlike the UNION proposal which is an extension of its existing system), it provides estimates for various operating costs and provides an estimate of the delivered price by customer class. These are illustrated in Exhibit 6.

Exhibit 6

NCE Estimated Rates ($/M3)	
Residential	0.46
Commercial	0.32
Industrial	0.27

[1] Appendix G contains a description of the important role of natural gas storage in Ontario.

These rates are not intended to reflect the OEB regulatory application and approval process that would be required to actually establish rates which customers would pay for the stand-alone case, but rather to illustrate the allocation of costs as estimated by NORTHERN. These rates include the cost of gas which NORTHERN estimates at $0.18/M3. It is NORTHERN's view that these rates would be indicative of those faced by consumers under its proposal.

2.3 Preliminary Screening

Earlier criteria were identified that would provide a high-level screening to eliminate an option that failed to meet minimum requirements for consideration. The two options presented above are next reviewed against these criteria.

Criteria	UNION Gas Proposal	Northern Cross Proposal
Implementation speed	Proposal designed to be started subject to detailed engineering and cost analysis and regulatory processes.	To be phased in over three years. First phase starts asap and the third in service by 2017. Staging provides flexibility.
Cost reduction for Customers	Since it is an extension of the existing system rates would be UNION's existing southwest region rates. These represent a large reduction in consumer costs.	NORTHERN provided estimates of customer rates based on estimated costs. These rates suggest a significant cost reduction for consumers. The option requires an analysis of costs and rates within the OEB's regulatory framework at the next stage of review.
Municipal Financial Capacity	The OEB regulatory process prevents the charging of unique rates to meet the financial needs of the option. Instead it identifies a required capital contribution by municipalities. The estimated amount would appear to be impractical without additional sources of revenue. This will be examined later in the review but could be an impediment to implementation of this option. Consistency with criterion requires	Since it is a stand-alone option it will generate its own set of rates for each customer class. Whether these rates are feasible or not will be considered later in the review.

Criteria	UNION Gas Proposal	Northern Cross Proposal
	further examination.	
Meets UNION Gas Supply Capacity	Consistency with UNION capacity included as part of the analysis.	NORTHERN's proposed supply system is said to be consistent with UNION capacity without the need for elimination of upstream bottlenecks. Independent analysis of the option will be needed to confirm this.
Manageability	This proposed system would be part of the UNION network and managed by UNION	The proposal is not specific on the structure of the entity that would manage the distribution company
Management & ownership options will be examined later in the review.		
Acceptable Risks	The proposal did not include a risk analysis. This will be done later in this review.	The proposal did not include a risk analysis. This will be done later in this review.

In summary, at this time there does not appear to be anything in either of the two proposals that might be identified as a fatal flaw that would prevent either from being given more thorough consideration (particularly in the context of existing Province of Ontario policy - see Appendices D, E and F for further details).

Chapter 3: Option Analysis

3.1 Demand Forecast

3.1.1 UNION Demand Forecast

As indicated in the option review above, UNION undertook a survey of residential and commercial customers to assess their likelihood of converting to natural gas in the event that that energy source became available. The responses were the basis for the estimation of conversion rates and ultimately the demand for natural gas. Exhibit 7 summarizes the results of the responses in the residential sector.

Exhibit 7

Residential Survey Responses (%) Space Heating					
	Oil Forced Air	Electric Forced Air	Propane	Electric Baseboard	Boiler
	(n = 39)	**(n = 53)**	**(n = 60)**	**(n = 65)**	**(n = 10)**
Penetration	13	18	20	22	3
Likely to be replaced in 2 years	36	28	20	34	20
Likely to convert to natural gas	69	68	83	52	50
Overall likely to convert	152/227 = 67%				

Source: UNION

Overall about two thirds of the respondents indicated they would switch to natural gas. Similar responses were obtained to questions dealing with water heaters and other appliances. Based on its experience with surveys in other areas UNION then discounted these planned conversions by 20% to arrive at its estimate of projected conversions. A similar procedure was followed using responses in the commercial sector, including the same discount rate.

Based on these results and those obtained for the commercial sector UNION prepared a time profile of conversion numbers for the residential and commercial customer classes. The results are summarized in Exhibit 8. Almost 80% of those who said they would convert indicated that they would do so within 2 years and over 90% within 5 years.

Exhibit 8

Summary of UNION Conversions (cumulative)			
	Year 1	Year 5	Year 10
North			
Residential	2,184	3,752	3,927
Commercial	253	363	373
South			
Residential	99	273	323
Commercial	60	98	103
Total			
Residential	2,283	4,025	4,250
Commercial	313	461	476

Source: UNION Gas Ltd.

With the profile of conversions established UNION then converted these numbers into demands for natural gas using annual averages for each customer class which it obtained from its experience in similar markets. The demand projections are summarized in Exhibit 9.

Exhibit 9

Summary of UNION Demand Forecast (M3)			
	Year 1	Year 5	Year 10
North			
Residential	2,369,640	8,141,840	8,521,590
Commercial	1,458,241	4,184,519	4,299,795
South			
Residential	107,415	592,410	700,910
Commercial	345,828	1,129,705	1,187,343
Total			
Residential	2,477,055	8,734,250	9,222,500
Commercial	1,804,069	5,314,224	5,487,138
Industrial	15,931,980	15,931,980	15,931,980
Total Demand	20,213,104	29,980,454	30,641,618

Source: UNION

The industrial volumes are assumed to come on in the first year of operation and at their forecast values. The residential and commercial sectors, however, are phased in over time. When all conversions are complete industrial volumes are over half the total volumes projected.

3.1.2 NORTHERN's Demand Forecast

The NORTHERN demand forecast is based on the UNION projections. However, there is no time profile for conversions and volumes are higher for each customer class than UNION. Exhibit 10 shows NORTHERN's demand projections and compares them with UNION for each customer class.

Exhibit 10

NORTHERN Demand Projections			
	Customers	**Volume (M3)**	**UNION (M3)**
Residential	4,513	10,233,740	9,222,500
Commercial	504	8,140,370	5,487,138
Industrial	5	19,884,070	15,931,980
Total Demand		**38,248,180**	**30,641,618**

In the case of commercial demand the difference is largely due to NORTHERN's inclusion of a separate estimate for a class of customers referred to as grain dryers. The six customers in this class account for some 30% of total commercial demand. The industrial class consists of five customers. No details were provided on the process used to estimate these demands.

3.1.3 Innovative Research Customer Surveys

Innovative Research Group Inc. (INNOVATIVE) was retained by Borden Ladner Gervais LLP on behalf of the Municipalities of Kincardine, Huron-Kinloss and Arran-Elderslie to design and execute a survey to ascertain demand estimates for natural gas conversion among select residents and business establishment.

The goal of this research by INNOVATIVE is to assess the market potential for natural gas line connections among both residential homeowners and small-medium sized business establishments within a predetermined service area in the following three municipalities:

- Kincardine;
- Arran-Elderslie; and
- Huron-Kinloss

Survey results have been used to provide the required primary market potential data to complete the load forecast model which is required for the proponent’s business case and subsequent Ontario Energy Board filings.

Key Findings

Overall, a plurality of residential property owners and a majority of business establishments in the study area say they are likely to convert their home or space heating to natural gas when it is made available.

When it comes to water heating, residential property owners are less likely to say they would convert when compared to home heating. However, approximately the same number of businesses would convert their water heating as would convert their space heating.

The key decision to convert appears to come down to conversion cost. The higher the conversion cost, the less interest in conversion among both residential property owners and businesses. This appears to outweigh benefits on longer term fuel cost savings.

Residential Findings

- 45% of respondents would likely or definitely convert home heating to natural gas if it were made available in their community. In terms of home heating, 24% of respondents currently have electric baseboard heating, 19% have propane forced air, 11% have oil forced air, 10% have electric forced air and 8% have boiler systems.

- In terms of residential water heaters, 36% of respondents say they would likely or definitely convert to natural gas if made available. Currently, most area water heaters are fueled by electricity (80%), while 12% use propane and 6% use oil.

The residential survey results are summarized in Exhibit 11.

Exhibit 11

Residential Home Heating Conversion by Community				
	Kincardine (n=342)	**Huron-Kinloss** (n=233)	**Arran-Elderslie (n=178)**	**Total (n=753)**
Household Sample Distribution	45%	31%	24%	100%
Home Heating Conversion				
Likely to Convert to NG	**36%**	**42%**	**64%**	**45%**
Would Depend	**16%**	**21%**	**15%**	**18%**
Unlikely to Convert to NG	**46%**	**34%**	**20%**	**36%**
Don't know	**2%**	**3%**	**1%**	**2%**
Occupancy Type				
Year Round	83%	68%	98%	82%
Seasonal (mostly summer)	11%	27%	1%	14%
Seasonal (throughout the year)	5%	5%	2%	4%
Type of Home Heating System				
Propane Forced Air	19%	19%	21%	19%
Oil Forced Air	7%	10%	20%	11%
Electric Forced Air	16%	5%	6%	10%
Electric Baseboard	28%	25%	12%	24%
Boiler	8%	7%	10%	8%
Other	16%	24%	21%	19%
Age of Home Heating System				
5 years or less	29%	28%	35%	30%
6 to 10 years	19%	24%	18%	20%
11 to 15 years	11%	13%	13%	12%
16 years or older	39%	32%	30%	35%

Business Findings

- Among business decision makers, 61% say they would likely or definitely convert space heating to natural gas if it were available. Currently, most area small-medium sized businesses use propane forced air (24%), followed by oil forced air and boiler systems (both 20%), and electric baseboard heating (15%).
- 62% would likely or definitely convert their water heating to natural gas. Most business water heaters are fueled by electricity (63%), followed by 24% propane and 6% oil.

The commercial survey results are summarized in Exhibit 12.

Exhibit 12

Business Heating Conversion by Community				
	Kincardine (n=69)	Huron-Kinloss (n=28)	Arran-Elderslie (n=36)	Total (n=134)
Sample Distribution	52%	21%	27%	100%
Conversion to Natural Gas				
Likely to Convert to NG	**54%**	**48%**	**83%**	**61%**
Would Depend	**25%**	**24%**	**0%**	**18%**
Unlikely to Convert to NG	**21%**	**28%**	**17%**	**21%**
Don't know	**0%**	**0%**	**0%**	**0%**
Age of business heating system				
10 years or less	51%	33%	58%	49%
11 years or older	46%	63%	42%	49%
Don't know	3%	3%	0%	2%
Type of system				
Propane Forced Air	28%	10%	29%	24%
Oil Forced Air	13%	21%	33%	20%
Electric Forced Air	6%	0%	4%	4%
Electric Baseboard	17%	19%	8%	15%
Boiler	19%	24%	18%	20%

A detailed report on the full results of the Innovative survey can be found in Appendix A.

These results found by INNOVATIVE vary in important respects from those reported by Ipsos-Reid in the survey undertaken as part of the Union proposal. Exhibit 13 compares the results for the residential heating. The likely-to-convert responses were higher across all fuel types in the Ipsos-Reid than in the later survey. The overall response is some 20 points lower than the Ipsos-Reid results. However, Union subsequently reduced its conversion estimates by 20% across the board based on experience elsewhere in arriving at its estimates of expected customer attachments. This places the attachments estimates in the same range as INNOVATIVE where no such discount was applied.

Exhibit 13

	Comparison of Survey Results		
	Residential Heating		
	Likely To Convert (%)		
	Ipsos-Reid	Innovative	
Oil forced air	69	46	
Propane	83	77	
Electricity forced air	68	40	
Electricity baseboard	52	30	
Boiler	50	45	
Other	-	31	
Total Sector	66	45	

The commercial survey results were also lower but the overall difference was less than in the case of residential respondents. The fuel categories are different in each survey which makes comparisons difficult or impossible for some fuel categories. In each case the share of forced air furnaces accounted for by propane was approximately 50%. The results are compared in Exhibit 14.

Exhibit 14

	Comparison of Survey Results		
	Commercial Heating		
	Likely To Convert (%)		
	Ipsos-Reid	Innovative	
Forced air furnace	78	78	
Boiler	87	54	
Electic baseboard	-	15	
Other	74	38	
Total Sector	73	61	

The survey results reflect various uncertainties such as conversion costs, the price of competing fuels as well as customer characteristics at the time of the survey such as the age of the existing heating equipment. Over time the experience of other regions of Ontario indicates that natural gas eventually takes the lion's share of the home heating market. Exhibit 15 compares the fuel penetration rates in South Bruce with that for Ontario as a whole.

Exhibit 15

	Residential Penetration Rates (%)		
	South Bruce	Ontario	
Propane	21	2	
Electricity	37	14	
Oil	12	5	
Natural gas	0	76	
Other	30	3	
	100	100	

The lower likely to convert numbers are evident in the demand forecasts prepared by Elenchus.

3.1.4 Elenchus Demand Forecast

Elenchus Research Associates Inc. (Elenchus) was retained by Borden Ladner Gervais LLP on behalf of the Municipalities to prepare a forecast of the potential natural gas demand for the business case for the expansion of natural gas distribution in Southern Bruce County, comprising three municipalities:

- Kincardine;
- Arran-Elderslie; and
- Huron-Kinloss

The forecast includes customers in three potential customer classes: industrial; commercial and residential. This breakdown of customer classes reflects the way in which regulated natural gas utilities typically structure customer classes for rate-setting purposes. For purposes of the business case it is anticipated that the Ontario Energy Board would approve a rate structure that relies on these three rate classes.

Potential Industrial Customers

Six potential natural gas customers were identified by the municipalities that would meet the definition of an industrial customer. Each of these customers would be expected to require in excess of 1,000 10^3 m^3 (one million cubic meters) of natural gas annually. Given the importance of these large volume customers to the economic feasibility of developing a natural gas distribution system for Southern Bruce County, each of these customers was contacted to discuss their potential natural gas usage and their interest in receiving natural gas service. Their existing energy loads were reviewed along with a discussion of any potential additional future requirements.

It should be noted that while the discussions included an indication of the interest in receiving natural gas service, the meetings did not result in a firm commitment to contract for a specific quantity of natural gas. At the time of the discussions, there was no indication of the rates that would be charged for natural gas service or any potential contribution in aid of construction that might be required. As such, potential customers were not in a position to commit to service going forward. In addition, future economic factors could impact their energy requirements and the corresponding potential usage. This would in turn impact the actual volumes that potential customers would require and therefore the volumes for which customers would be willing to commit.

A summary of the results for the industrial group is provided in Exhibit 16.

Exhibit 16

Total Potential Industrial Demand

	Annual Volume 10 3 m3	Existing Fuel Type	Interest in Natural Gas service
Commercial Alcohols	17,260	Compressed Natural Gas	Yes
Canadian Agra	12,500	None	Yes
OPG	1,400	Propane	Yes
Medical Marijuana Greenhouse	1,400	None	Yes
Bruce Power	0	Steam	No
Paisley Brick	1,000	None	Maybe
Total Industrial	33,560		

Potential Commercial Customer Demand

The commercial customer class includes all non-residential customers other than those identified as potential industrial customers. These are broken down into two sub classes, one of which was contacted directly by Elenchus (the MUSH sector) and the second covered as part of the survey undertaken by INNOVATIVE.

The MUSH sector is defined as including municipalities, universities (colleges), schools and hospitals. The potential end-users in this sector in the proposed natural gas service areas were identified and contacted. The potential natural gas usage for each site was determined and totalled. For the municipal sites, most facilities are currently using propane and could be easily converted to natural gas. Similarly, the schools are using propane and primed for natural gas conversion. The hospital in Kincardine uses diesel oil and the hospital in Chesley uses propane. It is anticipated that subject to competitive natural gas prices and available capital budgets for conversion costs, all of the potential customers in this MUSH would convert to natural gas when available. Total estimated MUSH demand is 1,393,000 M3 per year.

The estimate of demand for the rest of the commercial sector was based on the INNOVATIVE survey results. The percentage of businesses that are "likely to convert to natural gas" varies with business's existing heating system. These differences are likely to relate primarily to the cost of converting from the business's existing system to natural gas. Hence, the highest willingness to convert is from propane and oil forced air to natural gas (85% and 81%, respectively), which involve relatively low of conversion costs, and the lowest willingness to convert is from electricity baseboard and forced air (37% and 20%, respectively) which are relatively expensive. Other factors affecting the willingness to convert would include the age of the business's existing equipment and the relative energy cost.

The percentage of businesses that would be likely to convert is 57.4% and an additional 13.8% would be in the "it would depend" category. Hence, the combined total indicates that roughly 65% of businesses can be considered to be potential natural gas customers. Given the margin for error identified by INNOVATIVE for the business survey, it would seem reasonable to expect something in the range of 60% to 70% of businesses to be willing to convert, with the actual number converting depending on factors such as the actual delivered cost of natural gas, financial assistance that is available for conversion costs, etc.

The survey conducted for Union Gas three years ago (August 2011) indicated that 81% of business respondents stated that they are likely to convert their space and/or water heating systems to natural gas, with 73% likely to convert only their space heating systems (implying 8% would convert only their water heating systems). These figures are somewhat higher than the corresponding results of the more current INNOVATIVE survey. The difference between the surveys exceed the margin for error slightly which suggests that they may be other factors involved in the survey design or in circumstances that have altered the views of natural gas within the business community over the past three years.

It is generally recognized that the actual number of customers that connect to a new natural gas distribution system when it becomes available tends be lower than the number that express interest in a survey that does not require a financial commitment. For this reason, Union discounted the results of its survey by 20% as the basis for its volume forecast; hence, their forecast assumed that 65% of businesses would connect to the distribution system.

For the same reason, the percentage of respondents that stated that they are "likely to convert to natural gas" for heating was used as the total number of conversions. In other words, our discount factor corresponded to the number of customers that would use natural gas for water heating only.

It can further be expected that some proportion of the respondents that said their decision to convert "would depend" on other factors would end up choosing natural gas if it becomes available. In the absence of other information, we have assumed that the proportion of this subset of potential customers that would ultimately connect to the distribution system would be the same proportion of all businesses surveyed that indicated they were "likely to convert to natural gas" (i.e., 57.4%).

Taking all of the factors described above into account, it was assumed for purposes of the demand forecast that 65.4% of business customers would convert to natural gas within five years. Furthermore, it was assumed that 50% of those customers would convert in the first year with an additional 30% converting in the second year. The remaining 20% of the total would connect over the next four years (i.e., 5% of the total each year).

The volumetric forecast was derived using an assumed annual volume per business customer of 11.5 10^3 m^3. It was also assumed that in the first year of connection the each new customer would use, on average, one-half of the normal annual volume since they would be connected for only half of the initial year, on average.

Exhibit 17 presents the demand forecast by year for the business segment of the commercial customer class.

Exhibit 17

Forecast of Commercial (Business) Customer Demand

	Conversions %	Customers Converted	Cumulative Customers	Volume (10*3 M3)
Year 1	50%	174	174	1,003
Year 2	30%	104	278	2,608
Year 3	5%	17	296	3,310
Year 4	5%	17	313	3,510
Year 5	5%	17	331	3,711
Year 6	5%	17	348	3,911
Thereafter	0%	0	348	4,012

Potential Residential Customer Demand based on the Innovated Residential Survey

The INNOVATIVE survey results indicate that the percentage of residential respondents that said they are "likely to convert to natural gas" varies with existing home heating system. These differences are likely to relate primarily to the cost of converting from the home's existing system to natural gas. Hence, the highest willingness to convert is from propane forced air to natural gas (77%), which involves a relatively low of conversion costs, and the lowest willingness to convert is from electricity baseboard (30%) which is relatively expensive. Other factors affecting the willingness to convert would include the age of the home's existing equipment and the relative energy cost at the time conversion is being considered. In general, the willingness of residential customers to convert is lower than the willingness of businesses to convert, presumably because the potential annual energy cost savings are generally lower for residential customers and the up-front capital investment may be harder to finance.

The percentage of residential consumers that would be likely to convert is 37.9% and an additional 13.6% would be in the "it would depend" category. Hence, the combined total indicates that roughly 43% of residential consumers can be considered to be potential natural gas customers. Given the margin for error identified by INNOVATIVE for the business survey, it would seem reasonable to expect something in the range of 40% to 45% of residential consumers to be willing to convert, with the actual number converting depending on factors such as the actual delivered cost of natural gas, financial assistance that is available for conversion costs, etc.

The survey conducted for Union Gas three years ago (August 2011) indicated that 66% of residential respondents stated that they are likely to convert their space and/or water heating systems to natural gas. These figures are significantly higher than the corresponding results of the more current INNOVATIVE survey, with the difference between the surveys exceeding the margin for error which suggests that they are other factors involved in the survey design or in circumstances that have altered the views of natural gas within the residential consumer community over the past three years.

As noted in the discussion of the demand forecast for commercial customers, It is generally recognized that the actual number of customers that connect to a new natural gas distribution system when it becomes available tends be lower than the number that express interest in a survey that does not require a financial commitment. For this reason, Union discounted the results of its survey by 20% as the basis for its volume forecast; hence, their forecast assumed that 53% of residential consumers would connect to the distribution system.

For the same reason, we used the percentage of respondents that stated that they are "likely to convert to natural gas" for heating as the total number of conversions. In other words, our discount factor corresponded to the number of customers that would use natural gas for water heating only.

It can further be expected that some proportion of the respondents that said their decision to convert "would depend" on other factors would end up choosing natural gas if it becomes available. In the absence of other information, we have assumed that the proportion of this subset of potential customers that would ultimately connect to the distribution system would be the same proportion of all businesses surveyed that indicated they were "likely to convert to natural gas" (i.e., 37.9%).

Taking all of the factors described above into account, it was assumed for purposes of the demand forecast that 43% of residential consumers would convert to natural gas within five years. Furthermore, it was assumed that 50% of those customers would convert in the first year with an additional 30% converting in the second year. The remaining 20% of the total would connect over the next four years (i.e., 5% of the total each year).

The volumetric forecast was derived using an assumed annual volume per residential customer of 2,170 m^3. It was also assumed that in the first year of connection the each new customer would use, on average, one-half of the normal annual volume since they would be connected for only half of the initial year, on average.

Exhibit 18 presents the demand forecast by year for the residential customer class.

Exhibit 18

<u>Forecast of Residential Customer Demand</u>

	Conversions %	Customers Converted	Cumulative Customers	Volume (10*3 M3)
Year 1	50%	1804	1804	1,957
Year 2	30%	1082	2886	5,088
Year 3	5%	180	3066	6,458
Year 4	5%	180	3247	6,850
Year 5	5%	180	3427	7,241
Year 6	5%	180	3607	7,632
Thereafter	0%	0	3607	7,828

<u>Summary of Demand by Class and Total Natural Gas Demand</u>

Exhibit 19 presents the volumetric demand by customer class by year and the forecast of total volumetric demand.

Exhibit 19

Volumetric Forecast of Natural Gas Demand

Total Load Forecast (10*3 M3)	Industrial	Residential	Commercial	MUSH Sector	Total Volume
Year 1	13,424	1,957	1,003	557	16,941
Year 2	26,848	5,088	2,608	1,114	35,658
Year 3	33,560	6,458	3,310	1,393	44,721
Year 4	33,560	6,850	3,510	1,393	45,313
Year 5	33,560	7,241	3,711	1,393	45,905
Year 6	33,560	7,632	3,911	1,393	46,497
Thereafter	33,560	7,828	4,012	1,393	46,793

The full Elenchus report is provided in Appendix B.

3.1.5 Summary of Demand Forecasts

The most recent market analysis allows us to summarize changes in the projections of market demand since the original UNION proposal in 2012. Exhibit 20 summarizes the projections that have been prepared to date.

Exhibit 20

	Comparison of Year 5 Demand Forecasts (000 M3)			
	UNION	NORTHERN	AMEC/EFG	Elenchus
Residential	8,681	10,224	9,532	7,241
Commercial	6,017	8,140	5,788	5,104
Industrial	15,932	19,884	21,485	33,560
Total	30,630	38,248	36,805	45,905

Both the commercial and institutional (MUSH) sectors are shown in the commercial customer class prepared by Elenchus. The latest Elenchus estimates provide projections that are 17% lower than UNION and almost 30 % lower than NORTHERN for the residential sector. The commercial sector is 15% lower than UNION and 35% lower than NORTHERN. The largest difference, however, is the Elenchus estimate of industrial demand which is more than double the UNION forecast and almost 70% higher than the NORTHERN projection. While industrial demand was about half of total demand in the UNION forecast, it is over 70% in the Elenchus forecast. The group AMEC/EFG is an independent consultant which reviewed the UNION proposal. Its conclusions on the technical feasibility of the project will be summarized next.

The variations in these estimates show the uncertainty associated with demand projections in general and the important role that incentives to convert will play in attracting customers to the natural gas market. The translation into revenues requires careful analysis since prices charged to residential and commercial customers are generally considerably higher than those charged to industrial customers. This will be examined in detail in section 3.4.2.

3.2 The Natural Gas Distribution System

3.2.1 The UNION Proposal

Based on its demand estimates by region and by customer class UNION proceeded to design a system of transmission and distribution lines and related equipment that it indicated was an "optimal system" in that it met the projected demands at minimal costs. Its modeling of the system indicated that it would be able to "provide adequate pressure at the inlet to the communities' distribution station". The model is based on a peak usage on a winter day. Pipe diameters were designed to ensure that the system had adequate capacity to meet projected demand, including for example grain dryers who have Fall peaking loads.

The system is illustrated in the schematic shown in Exhibit 21 and Exhibit 22 which show pipe lengths and sizes for each of the two transmission pipelines. The northern transmission line is referred to as the Kincardine Project and the southern one as Ripley and Lucknow.

Exhibit 21

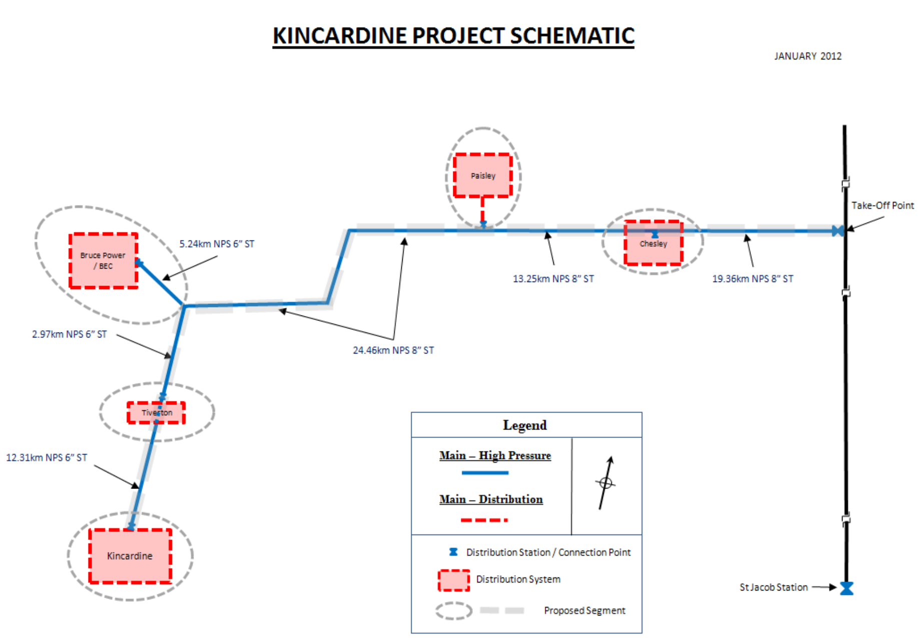
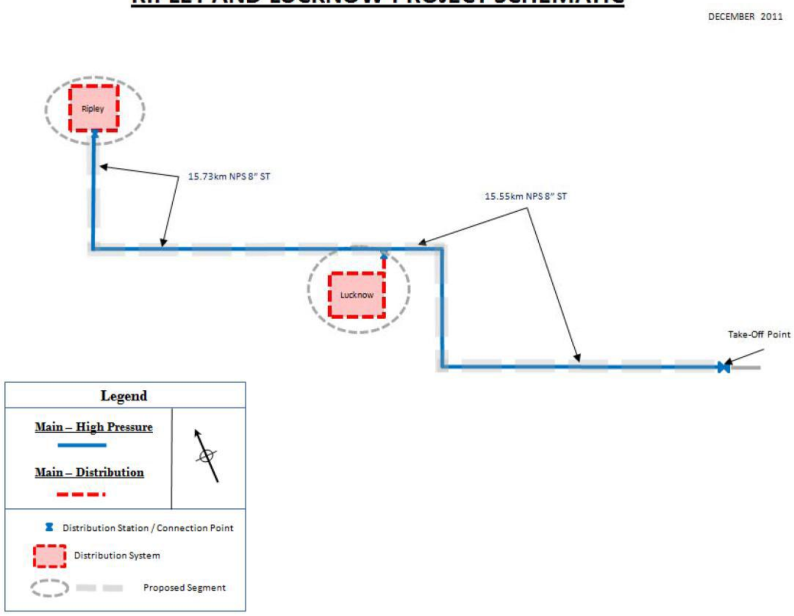


Exhibit 22

RIPLEY AND LUCKNOW PROJECT SCHEMATIC



The UNION proposal was subjected to a feasibility review undertaken by AMEC Environment and Infrastructure and Energy Fundamentals Group (AMEC/EFG). This review undertook a number of steps:

- A fatal flaw analysis that focused on system design rather than commercial feasibility;
- Suitability of the proposed route and associated transmission and distribution facilities;
- A review of the demand forecast (results shown in previous section);
- A preliminary estimate of landed costs; and
- The identification of an alternative to the UNION proposal.

In summary form the conclusions of this review by AMEC/EFG were the following:

1) Fatal Flaw Analysis and Suitability of Proposed Route

AMEC/EFG felt that there were no fatal flaws in the system as proposed by UNION. In particular it felt that the system was configured to meet the projected demands, taking into consideration peak load levels and seasonal variations in demand. On the subject of constructability it concluded that standard industry construction methods and techniques could be used to build the system to existing standards and codes with no identifiable impediments. On the subject of costs it stated that UNION's estimated capital spending estimate for the installed system was reasonable using a tolerance band of 20%. The review also had numerous comments on environmental and regulatory issues related to the project.

2) Estimate of Landed Costs

AMEC/EFG undertook to estimate landed costs using the OEB's rate-making principles. There are no UNION estimates against which to compare this since UNION never intended that the system would be a stand-alone entity for rate determination purposes. AMEC/EFG's cost estimates are not specific to a particular customer class. Rather they appear to have been derived by estimating total costs and dividing by estimated total volumes to be delivered. Nevertheless the AMEC/EFG estimates are useful. Exhibit 23 summarizes these estimates broken down into delivery costs and natural gas costs and with the delivery component separating out transmission from distribution. It also compares the estimates using AMEC/EFG's demand estimate against what the costs would be using UNION's demand estimate. The estimates have been converted into $/M3.

Exhibit 23

Estimated Landed Costs ($/M3)		
	AMEC/EFG Demand	UNION Demand
Transmission	.16	.19
Distribution	.11	.14
UNION transportation cost	.02	.02
Total delivery cost	.29	.35
Cost of gas	.21	.21
Total landed cost	.50	.56

This is compared with UNION's M1 residential rate which the study estimates at $.27/M3. The study had no comments on UNION's estimate of CIAC indicating that it did not have enough information to comment on it. However, given the difference between its estimate of the landed cost and UNION's residential rate it expected that the CIAC would be "sizeable".

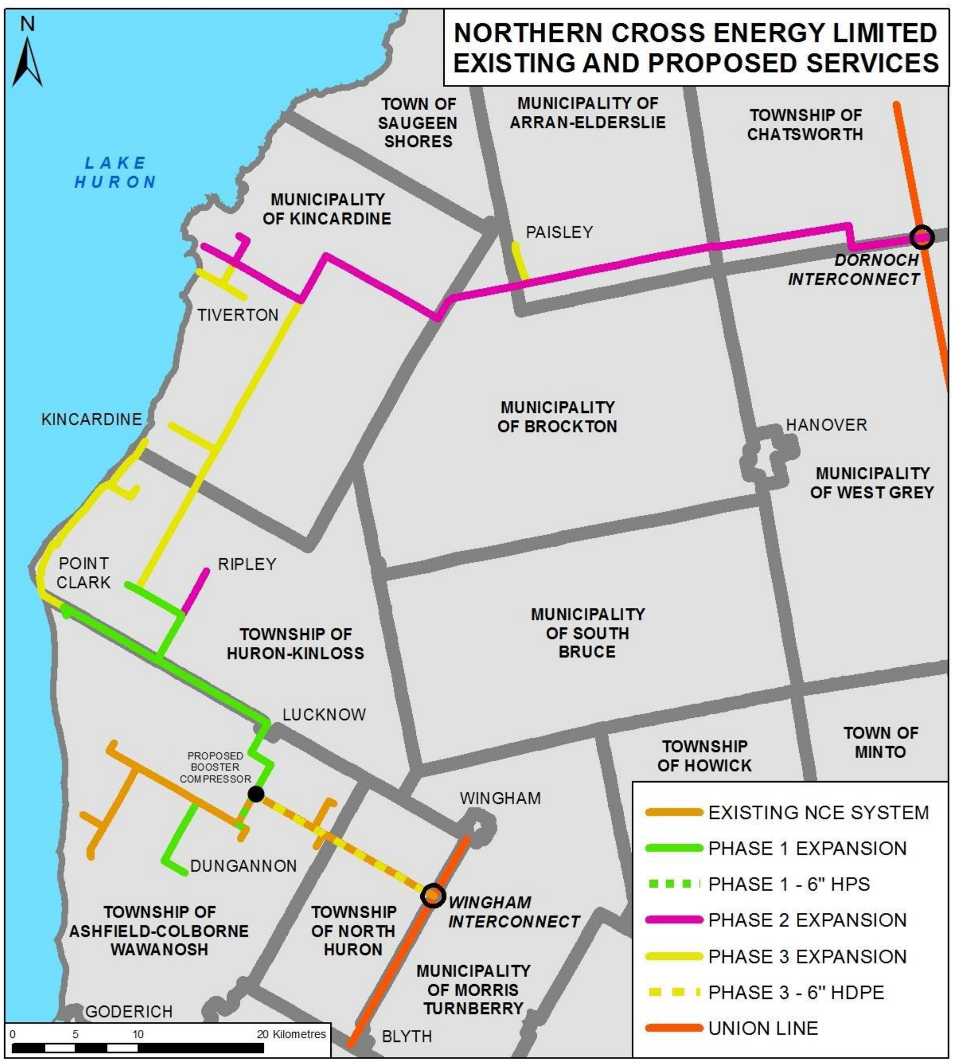
3) Alternative

Notwithstanding the fact that AMEC/EFG found the study to be feasible from a design and installation perspective and that the costs of the project were reasonable, it concluded that UNION's proposed project may not be "practical or justified". They recommended consideration of an alternative that would involve replacing the transmission part of the project with the infrastructure necessary to allow the delivery of Compressed Natural Gas to distribution facilities. This would save some $60 million in capital spending and allow the project to proceed in stages. While they felt this alternative was technically feasible they did not have the cost information to justify a more definitive conclusion regarding the commercial viability of the alternative.

3.2.2 The NORTHERN Proposal

The NORTHERN proposal consists of a three-phase expansion of its existing gathering system. A schematic of this phased expansion is provided in Exhibit 24. The first phase involves and expansion of NORTHERN's facilities in Huron County to Lucknow and agricultural commercial customers in Huron-Kinloss and is connected to the UNION system at the Wingham. This is followed by phase two expansion in Arran-Elderslie, connecting customers in the Chesley, Paisley and Tiverton areas to the UNION system at the Dornoch connection point. Phase 2 connects roughly half the forecast industrial loads and also connects Ripley to the earlier Phase 1 expansion. Finally, phase three connects phases one and two and the communities of Kincardine, Tiverton and Point Clark between the two.

Exhibit 24



The phased approach recommended by NORTHERN allows for the possibility of early connection of high demand industrial and commercial customers. Given Elenchus' demand projections showing industrial customers accounting for over 70% of total demand and the fact that the conversion process is expected to be shortest in the industrial sector this could be an important contributor to the project's economic viability.

The system consists of 64 km of NPS 8 high density polyethylene (HDPE) main, 114 km of NPS 6 HDPE main and 27 km of NPS 4 HDPE main as well as NPS 1.25 to 2 medium density polyethylene distribution pipes. The estimated total capital cost of the system is $70.2 million, some $26.7 million lower than the UNION proposal. The difference is primarily due to the absence of transmission pipe in the NORTHERN proposal.

A preliminary risk assessment of the NORTHERN proposal was undertaken by DR Quinn whose report can be summarized as follows:

- The NORTHERN proposal intends to replace natural gas transmission infrastructure with gas distribution infrastructure augmented by compression and storage. The feasibility of this approach requires closer independent examination.
- The gap in estimated capital expenditures between the two projects is significant. An independent review of all the major cost components is essential.
- A newly established utility needs to demonstrate that it can operate a system within the standards established by the Technical Standards and Safety Authority. This needs to be dealt with explicitly in the proposal, including its costs. NORTHERN recently completed a TSSA audit with only minor non-conformances. It has estimated related costs and included them in operating cost estimates but these need further refinement.
- The use of HDPE pipe for moving gas between load centres limits the ability of the operator to vary pressure to meet load increases. The implications of design sizing for meeting load centre variations require closer examination.
- Natural gas storage is a useful feature of the system but it must permit extraction at rates that meet system needs. There is inadequate information in the NORTHERN proposal to assess this capability which requires further examination.

DR Quinn's report is attached as Appendix C.

3.3 Natural Gas Rate Determination

The establishment of rates under each of the proposed UNION and NORTHERN options is very different. The UNION proposal involves an expansion of UNION's existing system and so is subject to the Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas

System Expansion in Ontario. Of paramount importance under these guidelines is the OEB's principle **"**to ensure that no undue cross-subsidy or rate impacts result from distribution system expansion". Later in the Guidelines the Board points out that the rates to be used in assessing an expansion are "rates derived from existing rate schedules".

The NORTHERN proposal on the other hand involves the establishment of a new natural gas distributor whose only customers would be those in the South Bruce. This would involve the establishment of a new set of rates that relate to these customers alone. The process for doing so would be the OEB's well-established cost-of-service approach to rate determination. The following looks at rate determination in each case.

3.3.1 Rates Under UNION Proposal

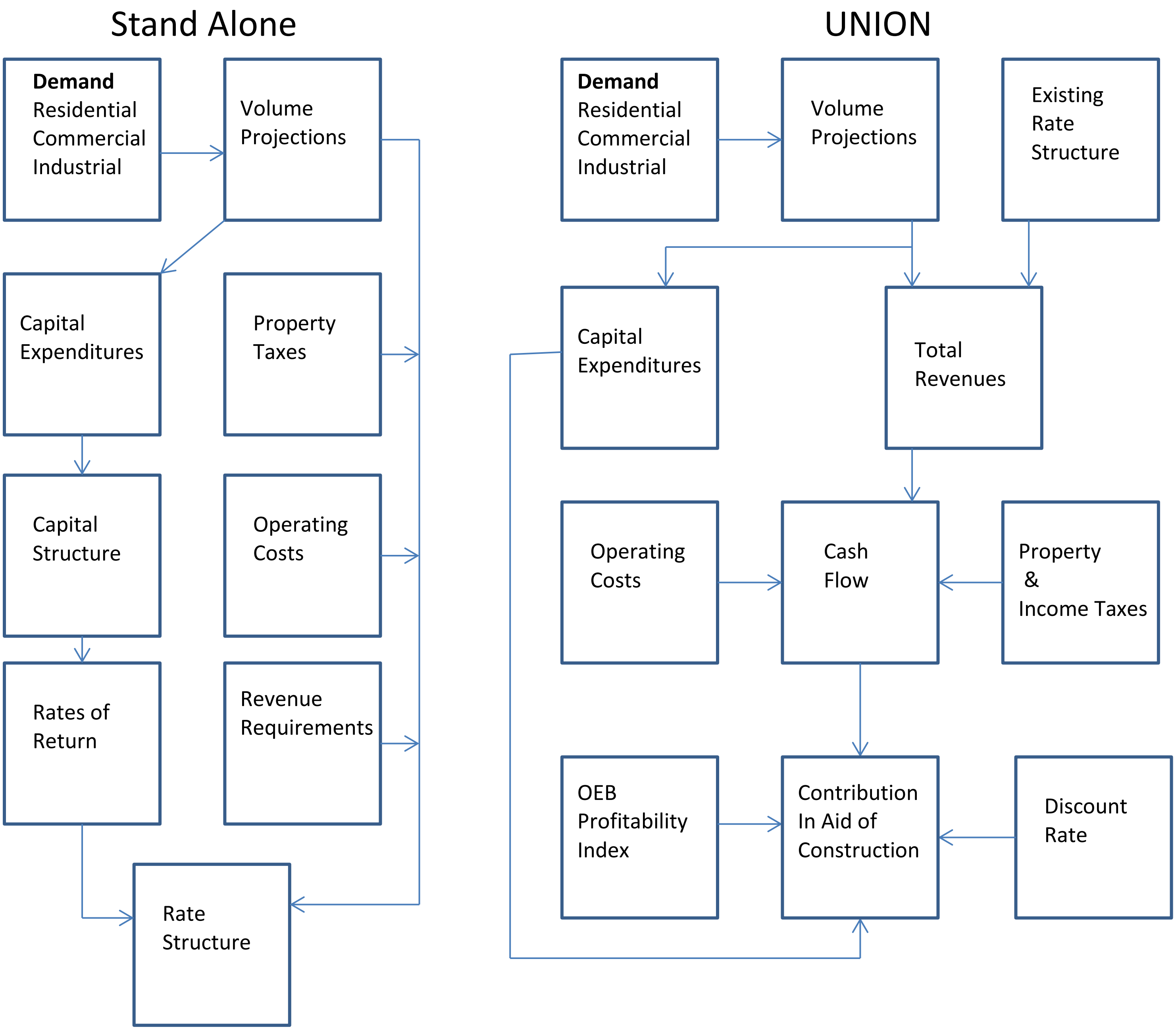
Exhibit 25 illustrates the regulatory procedure applicable to each proposal. The right side of the chart shows the procedure related to expansion of the UNION system. Projected volumes from the additional customers times the existing rates for each customer class net of incremental operating costs and taxes determines the incremental positive cash flow from the expansion. This is matched against the negative cash flows arising from required capital expenditures and possibly some increase in working capital requirements.

The Board's requirement is that the present value of the net cash flow over a period specified by Board procedures be at least zero. Another way of stating the same rule is to calculate what is called the profitability index. This is the absolute value of the ratio of the present value of cash inflows to cash outflows. This ratio must be at least 1. If the ratio is less than one then cash outflow must be offset by contributions-in-aid-of-construction (CIAC) until the target ratio of 1 is reached.

An example of the use of this procedure is the recent decision on the expansion of UNION's network to Red Lake Ontario. The primary user of gas in the area will be Goldcorp which operates the Red Lake Gold Mine in the area. About 70% of the proposed natural gas line capacity for the area would be used by Goldcorp with the remaining 30% used by residential customers and small businesses in the area. The capital expenditures required for the project are $26.9 million and to meet the OEB profitability index requirement the application pointed out that the proposed facilities have a net present value of zero with Goldcorp paying a CIAC of $25.6 million. Consumers in the region pay the same rate as others in UNION's northwest region with the incremental costs of the expansion picked up by Goldcorp in its aid to construct contribution.

In the UNION proposal there are two line extensions, one for the northern municipalities and one for the south. UNION undertook a separate economic analysis of each of these lines consistent with the OEB guidelines on system expansion. The northern line required capital expenditures of $75.1 m and to meet the OEB target of profitability index of 1.0 it required a CIAC of $66.5 m or almost 90% of capital spending. For the southern line capital spending was estimated at $20.9 m with $20.2 m, or 97%, required in CIAC.

Exhibit 25
OEB Regulatory Procedures



3.3.2 Rates Under the NORTHERN Proposal

NORTHERN proposes a stand-alone natural gas distribution company which would have rates set for customers in the area based on the rate determination procedure established by the OEB, using costs developed for the project. An overview of the process is provided in left side of Exhibit 25. In the most general terms the rate determination process has two fundamental steps. The first is to determine the revenue requirements of the utility. This is done by building up all projected costs including both the costs of operations and capital costs. The second step involves designing a rate structure that would provide these revenues in a fashion that is consistent with each customer group's contribution to the utility's costs. This Cost of Service (COS) procedure is followed for UNION which has 1.4 million customers and NRG which has 7,110 customers.

UNION's last cost of service rate application was for the rate year 2013 and NRG's was for 2011. Rates are set for five years with annual adjustments that are essentially formula based and quarterly adjustments for changes in the commodity cost of natural gas. Given the similarity in size and location NRG is judged to be the better model for current purposes.

NORTHERN did not follow this regulatory procedure but estimated rates using its own assumptions regarding costs and rate design. However, as a stand-alone entity the distribution company would be required to determine rates in a manner consistent with the known regulatory rules. Consequently, the procedure followed by NRG in its last COS is used here to establish rates that will be the basis for the financial projections prepared for the distribution company. There will necessarily be some differences since we are dealing with a start-up situation.

The first step in the process is to establish the rate base for the company. This normally consists of the net fixed assets of the company plus an allowance for working capital. In the present case the fixed assets consist of the investment in the start-up. Normally the next step would be to determine operating revenues using projected demand. Since there are no initial rates this step will be limited to forecasting demand. In the following the analysis will be done using each of the UNION demand projections and those prepared by Innovative/Elenchus. This is followed by estimating overall operating costs which consists of operating, maintenance and administration (OM&A) costs, depreciation, taxes and the cost of gas. In this case benchmarks based on NRG are used for OM&A and property taxes and established OEB rates are used for depreciation. If the municipalities become shareholders that own the new natural gas distribution company under Provincial municipal services corporation legislation, it is believed this company can be structured to operate on an income tax free basis. That is, the income taxes exempt nature of the corporation would result in cost savings since such tax liability payable would not be required to be recouped from consumers and therefore there is no need for a cost provision for this. The cost of gas is based on the latest allowed gas cost by the OEB. The next step is the determination of the cost of capital. This is done by applying the OEB's deemed capital structure and rates of return on each type of capital (equity and debt) to the rate base.

The sum of the costs estimated by this procedure determines the overall revenue requirement of the company. The next step is to establish a rate structure that when applied to the forecast demand will yield the revenue requirement. The process used by the OEB is a complicated one in which the rate design is based on the allocation of costs to the customer classes. This process requires data which is not available and which is unnecessarily complicated for present purposes. Consequently, a simpler process is used which uses the ratio of prices among customer classes at NRG as a benchmark.

With rates determined in this manner it is then possible to determine the financial performance of the company over a 10-year period and to examine the annual costs for each customer group. This, compared to current costs using other energy sources provides an estimate of anticipated energy cost savings.

3.4 Option Economic Evaluation

3.4.1 UNION Proposal

The economic analysis of the UNION option is fundamentally different than the stand-alone option proposed by NORTHERN. Whereas the latter determines from basic principles a rate structure that will cover all of its costs, including a return on capital, the former regards the provision of natural gas distribution service to the project area as an expansion of its existing system which must be done within its existing rate structure. Any shortfall in the revenues generated from the expansion must be covered by CIAC.

The model used by UNION to undertake its Discounted Cash Flow (DCF) analysis has been replicated in its essential features to examine the impact of alternative assumptions on the resultant estimated CIAC. The first task is to calibrate it as closely as possible to the estimated CIAC contained in the March 2012 UNION report to the municipalities involved in what it referred to as the Kincardine Group. Very little of the underlying information was included in the study so UNION was asked to provide the necessary supporting background. While UNION did not make available the model it used in preparing its report, it did provide sufficient information for the purposes of the present analysis.

UNION prepared a forecast of revenues based on the demand projections described earlier and its existing rates for the southwest region. The OEB procedure calls for the inclusion of 40 years of residential revenue projections. In the case of the commercial sector commercial customers were broken down into small, medium and large and differentiated average consumption rates applied to each group. The OEB procedure requires 20 years of commercial revenue projections. In the case of industrial demand potential customers were identified individually and interviewed to determine likely consumption levels. Views on the likely industrial customers and their use of natural gas has varied since the time the report was prepared but for the purpose of this analysis the original industrial entities and their estimated use were retained. The OEB procedure uses 10 years of industrial revenue projections.

Since UNION is constrained to use existing distribution rates one might have expected that revenues would have been derived by applying these rates to the volumes estimated via the above process. However, UNION uses not the scheduled rates but rather what it calls margins. UNION indicated that these margins differed from rates in that they incorporate an estimate of incremental upstream costs occasioned by the expansion of demand.

As Exhibit 25 illustrates the next step is to convert the revenue projections into cash flow forecasts. This required the provision of estimates of operating and maintenance expenses as well as property taxes and income taxes. Against these positive cash flows are the negative cash flows related to the required investments. These amounted to $96.9 million spread over three years, 96% of which is in the first year. There is an additional small amount of capital spending in each of the following 7 years which UNION refers to as service costs.

As explained earlier the test imposed by the OEB to ensure there are no subsidies provided by existing customers is that the net present value of all cash flows be at least zero. Another way of looking at the same test is that the ratio of the present value of the positive cash flows to the negative cash flows, which is called the profitability index, must be at least one. The plug that is used to ensure this test is met is CIAC.

Exhibit 26 shows the result of examining four cases, one of which is based on the 2012 report and the other three result from simulating alternative assumptions. The focus is on the level of the CIAC. As one might expect the CIAC is highly dependent upon the revenue projections, or more specifically, the cash flows that result from the revenue projections. The higher the revenues, the lower is the CIAC. The cases shown are (i) the original case underlying UNION's initial estimate of CIAC provided in the 2012 report, (ii) a case estimated by using rates rather than margins but including the assumption of a 10% incremental upstream cost; this case will be used as the basis for comparisons with other cases, (iii) a case that excludes the 20% reduction in customer levels and the 10% incremental upstream cost, and (iv) a case that is the same as case (ii) but eliminates property taxes for 10 years.

Exhibit 26

Cases	CIAC ($m)
(i) 2012 UNION study	86.7
(ii) Revenues based on rates	85.7
(iii) No reductions in customers or revenues	81.6
(iv) Same as (ii) but reduced property tax	83.0

A few observations are worth noting. First, the risk to UNION diminishes with higher levels of CIAC. For example, an underestimate of revenues and cash flow means a higher CIAC. If revenues turn out to be higher, then UNION's profits will be higher than forecast. UNION may be required to return these revenues to customers in the future but it minimizes the risk of being in a revenue deficient situation.

Secondly, consumers in this model pick up none of the higher costs of servicing this area. Because UNION is constrained to charge the same rates and avoid any cross subsidization the gas consumers in the area would see the same rates as those in any other Ontario southwestern zone municipality. The burden of the increased costs of meeting the CIAC is placed on the municipalities or any other funding sources they can find to pick up part of these costs. UNION has mentioned the possibility of seeking OEB approval to implement temporary rate riders for the area to offset part of the CIAC. While UNION is unlikely to favour a stand-alone entity for the region some mechanism for allowing consumers in the area to share in the higher delivery costs for the project would seem to be a critical part of resolving the unacceptably high estimated CIAC.

The financials for the first 10 years related to UNION's March, 2012 are shown in Exhibit 27, which will be called the UNION Base Case. By way of comparison Exhibit 28 illustrates the financials related to Case (iii) above. This case estimates operations and maintenance costs by using the same ratio of these costs to revenues as in the UNION Base Case. Property taxes are kept at the same absolute levels as in the Base Case on the presumption that they do not vary with revenues and income taxes are estimated by using the implicit tax rate from the UNION base case.

The absence of the discount applied to conversions in Exhibit 27 means higher demands, higher revenues but also somewhat higher OM&A. The next higher positive cash flow reduces the CIAC by $4.1 m.

Exhibit 27

	DCF Analysis - UGL Base Case									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cash inflows	1	2	3	4	5	6	7	8	9	10
Distribution revenues	984,033	1,353,827	1,547,637	1,587,755	1,604,588	1,618,050	1,630,167	1,642,285	1,654,706	1,667,323
O&M expenses	246,008	338,457	386,909	396,939	401,147	404,512	407,542	410,571	413,677	416,831
Property taxes	338,032	355,741	364,805	365,385	365,965	366,544	367,124	367,704	368,284	368,864
Income tax	24,000	39,578	47,755	49,526	50,249	50,820	51,330	51,841	52,365	52,898
Total cash inflow	375,993	620,051	748,168	775,905	787,228	796,174	804,171	812,169	820,381	828,730
Cash outflows										
Capital expenditure	-93,335,511	-2,112,988	-911,874	-77,753	-77,753	-77,753	-77,753	-76,147	-76,147	-76,147
Contribution	85,709,000									
Change in WC	-19,795	-24,040	-10,129	-3,528	-950	-950	-950	-950	-950	-950
Total cash outflows	-7,646,306	-2,137,028	-922,003	-81,281	-78,703	-78,703	-78,703	-77,097	-77,097	-77,097
Net cash flows	-7,270,313	-1,516,977	-173,835	694,624	708,525	717,471	725,468	735,072	743,284	751,633
NPV cash flow per period	-6,897,830	-1,365,519	-148,462	562,843	544,693	523,312	502,035	482,620	463,009	444,222
Sum of period NPVs	-336									
Cumulative NPV	-6,897,830	-8,263,349	-8,411,811	-7,848,968	-7,304,275	-6,780,963	-6,278,928	-5,796,308	-5,333,299	-4,889,078
NPV Project	-336									
Profitability Index per period	0.03	0.09	0.15	0.21	0.27	0.33	0.38	0.43	0.48	0.53
Profitability index project	1.00									

Exhibit 28

	DCF Analysis - No discount of customer numbers & no discount of revenues									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cash inflows	1	2	3	4	5	6	7	8	9	10
Distribution revenues	1,095,357	1,661,927	1,903,467	1,954,213	1,975,898	1,993,210	2,008,863	2,024,516	2,040,544	2,056,750
O&M expenses	273,839	415,482	475,867	488,553	493,975	498,303	502,216	506,129	510,136	514,187
Property taxes	338,032	355,741	364,805	365,385	365,965	366,544	367,124	367,704	368,284	368,864
Income tax	29,009	53,442	63,768	66,016	66,958	67,702	68,371	69,041	69,727	70,422
Total cash inflow	454,477	837,262	999,028	1,034,258	1,049,001	1,060,662	1,071,152	1,081,642	1,092,397	1,103,277
Cash outflows										
Capital expenditure	-93,335,511	-2,112,988	-911,874	-77,753	-77,753	-77,753	-77,753	-76,147	-76,147	-76,147
Contribution	81,650,000									
Change in WC	-19,795	-24,040	-10,129	-3,528	-950	-950	-950	-950	-950	-950
Total cash outflows	-11,705,306	-2,137,028	-922,003	-81,281	-78,703	-78,703	-78,703	-77,097	-77,097	-77,097
Net cash flows	-11,250,829	-1,299,766	77,025	952,977	970,298	981,959	992,449	1,004,545	1,015,300	1,026,180
NPV cash flow per period	-10,674,411	-1,169,995	65,782	772,183	745,937	716,225	686,790	659,545	632,454	606,481
Sum of period NPVs	10,125									
Cumulative NPV	-10,674,411	-11,844,406	-11,778,624	-11,006,441	-10,260,504	-9,544,279	-8,857,489	-8,197,943	-7,565,490	-6,959,009
NPV Project	10,125									
Profitability Index per period	0.03	0.08	0.14	0.20	0.26	0.31	0.37	0.42	0.46	0.51
Profitability index project	1.00									

3.4.2 The NORTHERN Proposal

Under NORTHERN's stand-alone case the principal variable to be determined is not CIAC but the rates to be borne by consumers for the distribution of gas. These rates would cover all the costs of distribution. It starts with a projection of demand volumes for each of the customer classes. For the purpose of the economic analysis two sets of projections are used. The first uses the demand projections from the UNION report, adjusted to include growth in the number of customers over time. A comparison of the number of customers by customer class and volume projections between the original UNION projections and the adjusted numbers is provided in Exhibit 29.

The second case uses demand forecasts based on the projections prepared by Innovative/Elenchus and described in detail earlier in this report. An economic assessment was prepared under each set of assumptions.

Exhibit 29

Comparison of Demand Forecasts					
	2015	2016	2017	2018	2019
UNION Original					
No. customers					
Residential	2,282	3,404	3,933	3,978	4,023
Commercial	312	431	460	467	469
Industrial	6	6	6	6	6
Total	2,600	3,841	4,399	4,451	4,498
Consumption (000 M3)					
Residential	2,476	6,169	7,961	8,583	8,681
Commercial	2,022	4,668	5,544	5,885	6,017
Industrial	15,932	15,932	15,932	15,932	15,932
Total	20,430	26,769	29,437	30,400	30,630
Adjusted Values					
No. customers					
Residential	2,334	3,501	4,121	4,295	4,469
Commercial	321	445	508	527	546
Industrial	6	6	6	6	6
Total	2,661	3,952	4,634	4,828	5,022
Consumption (000 M3)					
Residential	2,532	6,331	8,270	9,131	9,509
Commercial	1,853	4,417	5,491	5,964	6,184
Industrial	15,932	15,932	15,932	15,932	15,932
Total	20,317	26,679	29,693	31,026	31,625

The major cost components considered in the development of rates are operations, maintenance and administration (OM&A), property taxes, depreciation, the cost of capital and the cost of gas. The last of these is a cost pass through for gas distributors and is set quarterly by the OEB. In each case NRG is used as a reference with differences reflecting unique features the new company.

In the case of OM&A NRG is a more useful model than UNION. The latter treats the area under consideration as an add-on to its extensive distribution network through southwestern Ontario. The former is a stand-alone operation similar to the one under consideration. Consequently, the average ratio of OM&A to sales volumes over the period 2006 – 2011 (the latest available from NRG's last COS application before the OEB) was used as a benchmark. Similarly, the ratio of property taxes to sales volumes was used for the same purpose.

The case of depreciation is somewhat more complex. The capital expenditures of a start-up natural gas distribution company are primarily in the form of installation costs for pipelines, meters, regulators and related equipment. These have a very long life and consequently the OEB sets the lowest depreciation rates for this category (in the range of 3.25% to 3.6%). Over time the depreciated value of these assets diminishes and other capital expenditures with higher depreciation rates, such as computers, increase in relative importance. NRG is a mature distribution company and consequently its average depreciation rate of about 6.5% in relation to net fixed assets would likely exaggerate the rate applicable to a start-up. Consequently, a depreciation rate of 3.5% was applied. The capital expenditures used are those prepared by NORTHERN, which are described in Section 3.2 of this report. They represent a reduction of $26.6 m from the capital expenditures in the UNION option.

A fundamentally important part of the process of rate determination is the estimation of the rate base and related capital structure of the company. The procedure followed is that outlined in the cost of service rate application of NRG for 2010. The rate base consists of two components net fixed assets and an allowance for working capital. The value for net fixed assets is taken from the estimated capital expenditures described by NORTHERN. Obtaining a benchmark for a working capital allowance was complicated by the significantly different estimates used by NRG and UNION. In the former case the working capital allowance is actually negative, largely because of the impact on working capital of security deposits held by NRG. In the case of UNION the allowance varies but is approximately 7% of the value of net fixed assets. In the case of electricity distribution companies it is set at 13% of operating costs and the cost of power. In the absence of a clear indicator of an appropriate measure the working capital allowance was set at zero for present purposes. Consequently, the rate base is the capital expenditure estimate of NEC of $70.2 m.

The allowed returns on capital are calculated with respect to the rate base. For this purpose OEB guidelines are used both in relation to the deemed capital structure and with regard to the appropriate rates of return for each source of capital. Exhibit 30 summarizes the determination of the return to capital to be included in the costs of service.

Exhibit 30

	Share of Capital	Capital ($m)	Rate (%)	Contribution to Cost ($000)
Long-term debt	0.56	39.3	4.88	1,918
Short-term debt	0.04	2.8	2.11	59
Equity	0.40	28.1	9.36	2,640
Total cost		70.2		4,617

The actual return to equity is, in fact a residual, determined after all costs have been covered. For present purposes it is assumed that a positive return on invested capital will not be earned until all potential customers have been converted to gas. In the case of the UNION option the conversion process continued until year ten. In the stand-alone case it is assumed to end in year five.

The final component of delivery cost included in the determination of rates for NRG is an estimate of income taxes. In the current case it is intended that the company be wholly-owned by municipalities and hence exempt from income taxes. Consequently, there is no income tax component of cost.

The last element of total cost to the customer is the commodity cost of gas. The OEB's setting of natural gas commodity charges was used for this purpose. Since an individual value could be misleading, the average value for the period July 2013 to July 2014 was computed. The charges vary considerably for UNION and for NRG largely because the latter rates include charges for storage and transportation. Since these charges will be included in rates for South Bruce the NRG average rate was used. This may exaggerate somewhat the cost of gas if there are advantages to be realized from local storage but is a good first approximation.

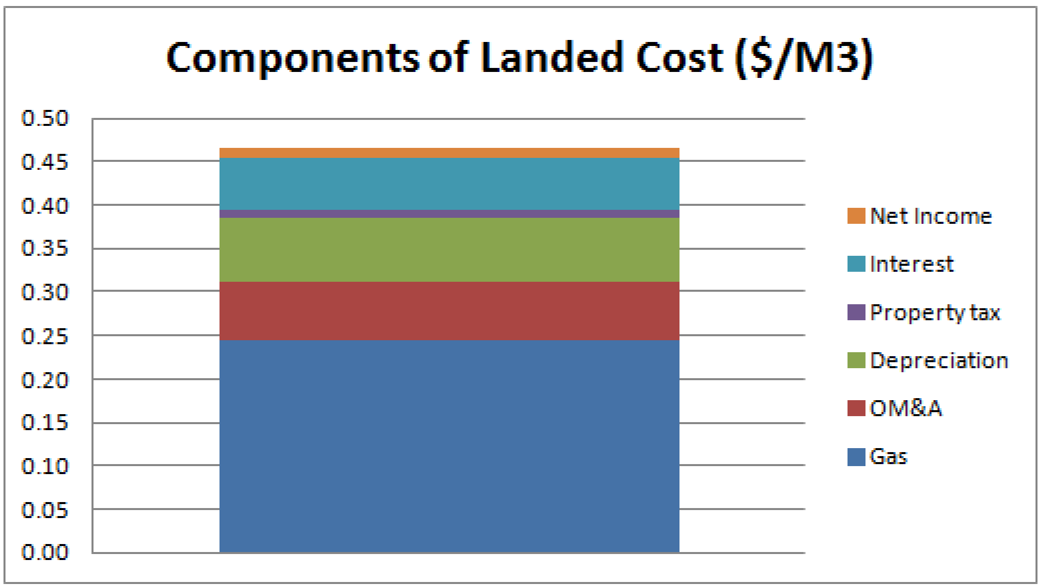
Results

The analysis was carried out using each of the adjusted UNION demand projections and the forecast based on the work of Innovative and Elenchus. Each set of results is reviewed here, beginning with the results using the adjusted UNION demand numbers.

With the components discussed above we can derive an estimate of total revenue requirements and an implicit average rate across all customers. It is still necessary to create a rate structure for each of the customer classes. In the regulatory process this is a complicated procedure based on cost allocation. For the present purposes NRG was used as a guideline. NRG's ratios of implicit prices for the commercial and industrial classes to residential were used here. These rates would cover all costs, including a return on capital employed. Given the large capital expenditures required and the consequent large depreciation component of total costs to be covered in prices, rates were phased in over the first five years of operation until a positive return on capital is earned in year four. The allowed rate of return on capital is not realized within the first ten years. Thereafter rates would be rebased every five years.

By Year 5 all conversions are complete and an estimate of the overall landed cost of gas can be derived. Moreover, we can show the contribution to this total unit cost of each of the cost components. This is illustrated in Exhibit 31. The cost of the gas commodity is the largest component of the cost of gas, accounting for over 50% of the total landed cost. OM&A, depreciation and interest all account for between 12% and 15%. The return on equity capital accounts for just over 2% of total landed costs in Year 5. This increases to 7.6 % by Year 10. Property taxes are a very small part of total costs throughout.

Exhibit 31



None of the customer classes sees the overall landed unit cost. What they see are individual rates for their specific group. The determination of this rate in the regulatory process is on the basis of cost allocation to each group. Of course, there are an infinite number of combinations of rates that could yield the overall revenue requirement. For our purposes the relative implicit rates inherent in the NRG was used as a guideline to establish a rate structure consistent with the forecast of revenue requirements.

Exhibit 32 illustrates the implicit delivery rates required to achieve positive net income in year 5 in the stand-alone case compared to the rates assumed in the UNION report and the rates charged by NRG. By implicit rate is meant the total revenue raised in the customer class divided by the total volume sold to that class. Various rate designs could be used to realize the indicated implicit prices.

Exhibit 32

	Implicit Average Delivery Rate (Year 5 $/M3)		
	Stand- Alone	UNION*	NRG**
Residential	0.430	0.200	0.231
Commercial	0.341	0.145	0.147
Industrial	0.077	0.013	0.057

** Based on 2014 UNION rates and proposal assumptions.*
*** Based on escalated 2011 NRG rates.*

As is evident the delivery rates are significantly higher than those faced by UNION customers in the southwestern Ontario region and also considerably higher than NRG rates but comparable to the landed costs estimated by EMAC/EFG. This simply reflects the very high capital costs allocated over a relatively small customer base. This would improve over time as the customer base grows and capital costs are depreciated but given the slow growth in household formation and business growth this would likely take some time.

To the delivery rate must be added the cost of gas which is assumed to be $.28/M3, based on OEB allowed rates for NRG. The resulting annual costs for the average residential consumer are indicated in Exhibit 33.

Exhibit 33

	Residential Average Annual Cost		
	Year 1	Year 5	Year 10
Avg. ann. consumption (M3)	2,170	2,170	2,170
Residential Rate $/M3	0.77	0.67	0.69
Total cost ($)	1,671	1,454	1,497

The Year 5 estimate is after all conversions have occurred so represents the ongoing annual cost, given the assumed distribution and gas cost rates. In Exhibit 34 this is compared to the costs of alternative fuels estimated in Exhibit 4.

Exhibit 34

Comparison of Annual Residential Heating Costs	
Fuel Type	**Annual Cost ($)**
Electricity	3,159
Heating Oil	3,644
Propane	2,331
Natural gas	1,454

The majority of households are currently on electricity followed by propane and then heating oil. The annual savings between natural gas and electricity is estimated at $1,600 compared to just under $900 for propane and about $2,100 for heating oil.

The allocation of revenue requirements, of course, reflects the rate structure assumed. This can be altered to ease, for example, the burden on residential consumers and reduce the annual cost of natural gas consumption to this customer class. This would reduce the uncertainty associated with residential sector conversions. However, it would come at the expense of increasing commercial and/or industrial rates which would increase the uncertainty of demand projections in these customer classes. The price sensitivity of demand in each customer class is critical information that may be derived in part from survey information. However, an understanding of price elasticity is not likely to emerge until the market has been operating for some years.

As indicated earlier the delivery rates used were increased gradually over the forecast period, consistent with the conversion of customers from alternative fuels to natural gas. This results in inadequate revenues to meet all costs in the early years.

Exhibit 35 illustrates the profitability of the distribution company over the ten-year forecast period.

Exhibit 35

	Return on Equity		
	Year 1	**Year 5**	**Year 10**
Net Income ($m)	-3.0	0.3	1.3
Return on Equity Rate Base (%)	-10.7	1.2	4.7

Pro forma financial statements were prepared for a 10-year period for the stand-alone Base Case. The income statement in Exhibit 36 shows revenues growing rapidly in the first five years of operation as conversion takes place and then slowly thereafter responding to growth in households and economic activity. Profitability is reached in Year 4 and then grows slowly thereafter as rates are increased gradually according to an annual escalator of 1.5%.

The implementation of higher overall rates would impede the conversion of customers to natural gas and possibly undermine the viability of the project.

Exhibit 36

Income Statement	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenue										
Service Revenue	3,003,428	5,061,876	6,130,939	6,636,894	6,957,187	7,203,726	7,444,141	7,655,494	7,872,777	8,096,159
Residential	1,338,181	2,724,615	3,480,155	3,824,491	4,041,824	4,201,969	4,357,451	4,494,056	4,634,600	4,779,192
Commercial	526,474	1,181,406	1,477,592	1,621,612	1,706,711	1,774,974	1,841,506	1,897,576	1,955,357	2,014,905
Industrial	1,138,774	1,155,855	1,173,193	1,190,791	1,208,653	1,226,782	1,245,184	1,263,862	1,282,820	1,302,062
Commodity Revenue	5,597,228	7,350,181	8,180,309	8,547,754	8,712,793	8,830,453	8,936,121	9,007,774	9,080,350	9,153,864
Other Income	0	0	0	0	0	0	0	0	0	0
Costs										
Cost of Gas	5,597,228	7,350,181	8,180,309	8,547,754	8,712,793	8,830,453	8,936,121	9,007,774	9,080,350	9,153,864
OM&A	1,360,489	1,786,571	1,988,345	2,077,659	2,117,774	2,146,373	2,172,057	2,189,473	2,207,114	2,224,982
EBITD	1,642,939	3,275,305	4,142,594	4,559,235	4,839,413	5,057,353	5,272,084	5,466,020	5,665,663	5,871,176
Depreciation	2,457,574	2,457,574	2,420,710	2,384,400	2,348,634	2,313,404	2,301,837	2,313,346	2,324,913	2,336,538
Property taxes	221,144	225,788	230,868	236,063	241,374	246,805	252,359	258,037	263,842	269,779
EBIT	-1,035,780	591,943	1,491,015	1,938,772	2,249,405	2,497,143	2,717,889	2,894,637	3,076,907	3,264,860
Interest	1,974,246	1,839,667	1,839,667	1,874,882	1,910,097	1,945,312	1,945,312	1,945,312	1,945,312	1,945,312
Pre-tax Income	-3,010,026	-1,247,724	-348,652	63,890	339,308	551,831	772,577	949,326	1,131,595	1,319,548
Income taxes	0	0	0	0	0	0	0	0	0	0
Post-tax Net Income	-3,010,026	-1,247,724	-348,652	63,890	339,308	551,831	772,577	949,326	1,131,595	1,319,548

After the initial large capital expenditure capital spending is below depreciation for the first five years resulting in moderately falling net fixed assets. Thereafter it is slightly above depreciation reflecting slow growth in market demand. The financing of capital expenditures is designed to meet the OEB deemed capital structure. Dividends are zero or insignificant until Year 6 when they are set at 25% of net income.

A case was also run that would result in the realization of the allowed 9.4% rate of return on the equity rate base by the tenth year of operation. It resulted in only two years of negative net income. This case required an overall landed price of $0.54/M3 by Year 5 compared to $0.46/M3 in the base case. The resultant increase in the residential rate would increase the average annual residential cost to $1,678 from $1,454.

The same analysis was undertaken using the revised demand projections prepared by Elenchus based on the survey undertaken by Innovative as described in section 3.1.4. Other assumptions related to prices, operating costs etc. remain unchanged. As Exhibit 19 illustrated the Elenchus demand forecast showed an increase in total demand which was due to a significant increase in industrial demand. Both the residential and commercial demand forecasts are lower.

The rates charged to residential and commercial customers are considerably higher than those for industrial customers. So while total demand is higher with the Elenchus forecast, total revenues are lower.

Whereas the Base Case with the adjusted UNION demand showed three years of negative net income, shifting to the Elenchus demand numbers results in eight years of negative income. Exhibit 37 illustrates the profitability of the Base Case with each set of demand numbers. With the new demand numbers net income reaches a low of -$3.4 m compared to -$3.0 m and in Year 10 is still only $0.1 m compared to $1.3 m with the adjusted UNION demand. The ROE numbers show a similar pattern. By Year 10 the return on equity rate base is still just 0.4%.

Exhibit 37

Net Income	Year 1	Year 5	Year 10
Base Case - UNION Demand	-3,010	339	1,320
Base Case - New Demand	-3,354	-648	102
Return on Equity Rate Base			
Base Case - UNION Demand	-10.7	1.2	4.7
Base Case - New Demand	-11.9	-2.3	0.4

To retain the profitability of the Base Case with UNION demand it would be necessary to increase prices in the Base Case using the Elenchus demand forecast. Given the lower demand numbers for each of residential and commercial the increase in these prices would have to be significant. Higher prices in these customer groups would threaten the conversion rates on which the demand forecast is based. For illustration purposes the industrial price was increased instead. Since the projected industrial demand is so large, small changes in price have a major impact on revenues. Exhibit 38 compares the implicit delivery rates for each customer class for five cases. The first column shows the rates under the Base Case using the adjusted UNION demand. The second column shows the rates in the Base Case with the Elenchus demand forecast (called new demand). The third column shows the rates that would restore the profitability of the Base Case with the adjusted UNION demand. Columns four and five show the comparative implicit rates calculated for UNION and NRG. The table shows that to restore the profitability profile the implicit industrial rate would have to be increased from $0.072/M3 to $0.10/M3.

Exhibit 38

Comparative Implicit Delivery Rates ($/M3)					
	UNION Dem.	New Dem.	ND-Hi Ind Pr.	UNION	NRG
Residential	0.430	0.426	0.426	0.200	0.231
Commercial	0.341	0.332	0.332	0.145	0.147
Industrial	0.077	0.072	0.100	0.013	0.057

Chapter 4: Risk Analysis

There are many uncertainties that could alter the financial results indicated above. In the case of the UNION option those uncertainties are primarily concerned with the factors that would alter the CIAC. The two primary ones would be the demand projections and capital spending. In the case of the NORTHERN option the uncertainties are all those factors that could affect rates and net income.

4.1. UNION Option Risks

The Base Case for the UNION Option shows a CIAC of $85.7 million. In the preliminary screen it was suggested that this requirement for an outlay on the part of the Municipalities in the absence of related revenues to offset it or contributions by other levels of government probably made the UNION unfeasible.

Also, the CIAC number itself is uncertain. Two cases were run to show the impact of the demand projections and capital expenditure estimate on the CIAC. In the first case demands were lowered by 15% across the board for all customer classes and in the second capital spending was increased by 15%.

The impact is shown in Exhibit 39.

Exhibit 39

UNION Option CIAC Sensitivity	
Case	**CIAC ($ m)**
Base Case	85.7
Low Demand	86.4
High capital spending	100.2

The lower demand level has its impact through lower positive cash flows over the life of the project. The impact on CIAC is relatively minor, increasing it by less than $1 m. The higher capital spending, however, has its full impact immediately resulting in an increase in CIAC of almost $15 m.

Of course uncertainty means that the driving variables could operate in the opposite direction as well. But even if that were the case the implied capital injection by the municipalities is a serious impediment to the implementation of the option. The heart of the problem is in the fact that the regulatory system (at least as currently configured) does not allow for the passing on to new gas customers the incremental cost of serving them on the existing system.

4.2 NORTHERN Option Risks

In the case of the NORTHERN stand-alone option two possible responses to changing drivers are possible. One approach would be to alter rates and leave profitability constant. The second is to leave prices unchanged and monitor the impact on profitability. The latter approach is consistent with the regulatory environment and easier to implement so this one is used.

Three sensitivities were developed for the stand-alone case, which focus on the impact of changes in selected variables on overall economic viability of the project as measured by net income and the return on the equity rate base. The sensitivities are:

i. An increase in capital expenditures of 15%;
ii. An across the board reduction in demand volumes of 15%; and
iii. An elimination of property taxes for 10 years.

The last of these is not an exogenous variable but rather one that is in the control of the municipalities which may be prepared to give up incremental property tax revenues to ensure the success of the project. All of these changes are looked in relation to the Base Case. The results are summarized in Exhibit 40.

Exhibit 40

Sensitivity Analysis			
	Year 1	Year 5	Year 10
Net Income ($m)			
Base	-3.0	0.3	1.3
Hi capex	-3.6	-0.4	0.5
Low demand	-3.1	-0.1	0.8
No property tax	-2.7	0.6	1.6
Return on equity (%)			
Base	-10.7	1.2	4.7
Hi capex	-11.4	-1.4	1.7
Low demand	-11.0	-0.4	2.7
No property tax	-9.9	2.1	5.7

Lowering demand by 15% causes the period of negative net income to shift from three to five years while 15% higher capital expenditures increases it to six years. The elimination of property taxes does not change this period but net income is higher by about $0.3 m in every year. The effects on the return on the equity rate base show a similar pattern. The higher capital spending case has the greatest impact followed by the other two cases which have similar impacts but operating in opposite directions.

An additional case examined included that of capital spending support of $15 million, which may be in the form of grants from either the provincial or federal governments. The financial effect is that it reduces capital expenditures without a corresponding increase in a cost component. This was looked at in two ways. The effect on profitability with no change in rates and the effect on rates with profitability essentially the same as the base case. The results are illustrated in Exhibit 41 where Low Capex 1 refers to the case in which the effect on net income is not offset by a reduction in delivery rates and Low Capex 2 is the cast in which there is a rate offset.

Exhibit 41

Low Capex Cases			
	Year 1	Year 5	Year 10
Net Income ($m)			
Base	-3.0	0.3	1.3
Low capex 1	-2.1	1.2	2.2
Low capex 2	-2.6	0.3	1.2
Residential Delivery Rate			
Base	0.529	0.425	0.455
Low capex 1	0.529	0.425	0.455
Low capex 2	0.483	0.389	0.416
Annual Residential Cost			
Base	1,745	1,520	1,585
Low capex 1	1,745	1,520	1,585
Low capex 2	1,646	1,441	1,500

The reduction in capital expenditure costs reduces related capital costs, which improves net income by half a million dollars in the first year, increasing to one million by the Year 5. Using an average reduction in rates across all customer classes and years it is not possible to offset the impact on net income exactly. The rate reduction changes the profile of net income over time but it is generally similar to the base case. The reduction in delivery rates that generally offsets the impact of the capital support on net income is about 8% - 9%. This results in a reduction in the average annual cost of natural gas to a residential consumer, including the commodity cost of gas, by about 5%.

In summary both options are exposed to risks from a variety of sources, the most important of which are conversions and the demand for natural gas and the capital expenditures on the project. In the UNION option these costs are captured in up-front CIAC which is borne entirely by the sponsoring municipalities. In the stand-alone option the impact of the risks tends to be distributed over time and can be shared by consumers and the municipalities.

Details on the alternative cases run can be found in Appendix D.

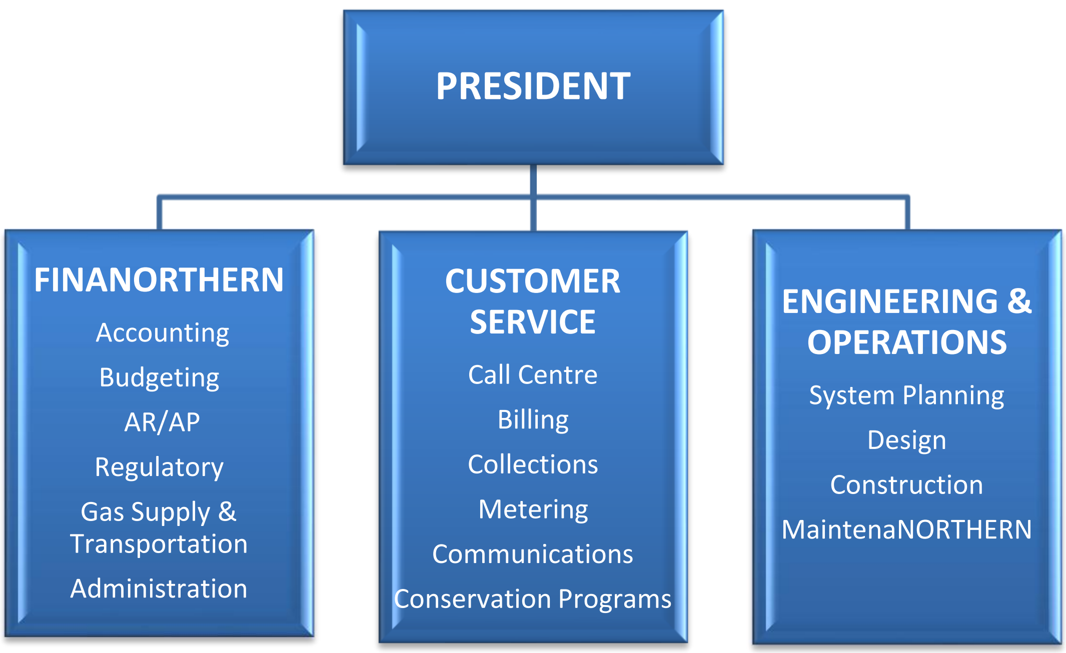
Chapter 5: Implementation and Management of NORTHERN Stand-Alone Option

5.1 Organizational Structure

The organization chart shown in Exhibit 42 outlines a basic functional organization for a natural gas distribution company with 10,000 customers or less. The organization is somewhat reflective of the larger Natural Gas Distribution Companies in the province but is more in line with the organization of Ontario's Electric Distribution Companies with 10,000 customers or less. There are four main functions in this organization, namely Executive (President), Finance, Customer Service and Engineering and Operations.

The Executive function or President provides overall leadership in the day to day management of the corporation and is the primary liaison between management and the company's board of directors. Finance provides direction and oversight of accounting and financial services to ensure compliance with applicable accounting and regulatory standards. Customer Service is responsible for all activities that deal directly with the customer. Engineering and Operations is responsible for system planning, design and construction of the distribution system along with activities related to the operation and maintenance of the system.

Exhibit 42



5.2 Finance

Under Finance the various roles include Accounting, Budgeting. AR/AP, Regulatory, Gas Supply and Transportation and Administration. Accounting is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with applicable accounting standards. Accounting would also include corporate finance, cash management, and risk management, supporting tax compliance and accounting systems. Budgeting involves financial planning and performance measures on a detailed level for one to two years and at a higher level for year three to five. AR/AP would address all daily accounting requirements including accounts payable, accounts receivable, and general accounting.

Regulatory is responsible for all submissions to the Ontario Energy Board ("Board") such as rate applications, compliance submissions and annual financial and performance requirements. In addition, Regulatory monitors Board policy developments and licence code amendments to ensure compliance with Board codes and guidelines.

The Gas Supply and Transportation activity involves the contractual arrangements and associated risk management for gas supply and/or upstream transmission services required to deliver gas to end-users. An embedded natural gas utility in the UNION Gas franchise area has options as to how it receives the service depending on the level of on-going management the utility wants to perform and its size. To understand these alternatives, the services in place for NRG and Kitchener, current embedded distributors, will be described.

An initial consideration is the choice of commodity procurement. The utility can receive a commodity procurement service from UNION with an M9 (large distributor greater than 2,000,000 m3 annually) rate or M10 rate for smaller utilities. The utility would pay the UNION Gas system gas rate equivalent to all non-direct purchase customers served by UNION. The alternative would be for the utility to purchase its gas from a third party supplier requiring separate contracting for commodity and potentially transport (potentially because the utility could receive an assignment of a transport contract from UNION Gas). Both NRG and Kitchener acquire their own gas commodity including NRG which sources gas produced in its own franchise area. Both meet delivery obligations to UNION in specified quantities and locations at the limits of UNION's territory. By choosing direct purchase, the utility avoids administrative charges by UNION for their procurement service but faces increased transaction costs of managing its own procurement of commodity and transport to the UNION specified delivery points.

The customer has choices for re-delivery by UNION to its franchise as outlined below.

Bundled Service: The simpler service is the M9/M10 service. UNION accepts the utilities' gas of equal daily quantities at the specified delivery points and re-delivers that gas to the utility at their customer meter(s) on an as needed basis. The only significant obligation of the receiving utility is to balance its deliveries and actual consumptions at key checkpoints (end of October and end of February) at certain limits and within a defined tolerance on the anniversary date of the bundled contract. NRG utilizes an M9 service.

Semi-Bundled Service: The T3 service is similar to M9 in that the utility provides UNION with equal daily quantities at specified delivery points for UNION's redelivery to the utility meter(s) on an as needed basis. However, a differentiating factor of the T3 service is the utility's rights and responsibilities to manage their storage inventory and deliverability inside of standard contractual parameters. This condition requires more on-going management but reduces the cost of the service and has been used to manage seasonal swings and market opportunities for the utility. Kitchener utilizes the T3 service.

Unbundled Service: The U9 service was eliminated from UNION's available rate schedule in 2013 as it was not utilized. This service had increased flexibility but required daily forecasting and management. Theoretically, it could be available upon request but has never been used by an embedded distributor in UNION's territory.

Administration addresses all issues related to human resources such as compensation, benefits administration, pension, health & safety, recruitment, labour relations, and the training and development of staff. Administration is also responsible for information technology services which include installation, maintenance, licensing and support of all hardware and software used by the company.

5.3 Customer Service

The function of Customer Service can be broken down into matters related to the Call Centre, Billing, Collections, Customer Accounts, Metering, Communications and Conservation Programs. The Call Centre is responsible for activities such as payment processing; move in and out requests; locates; and other call centre activities for the service territory of the company. Billing is responsible for issuance of all customer bills which is typically based on the meter reading cycle schedule to ensure timely billing of services. The billing activity also includes verification of customer meter reads; account adjustments; processing meter changes and mailing services. It also includes offering customers billing and payment options including an equal payment plan and a preauthorized payment plan. Collections include the collection of overdue active accounts, security deposits and final bills for service termination.

Metering includes meter installation, meter upgrades, meter verification, meter maintenance and meter reading. Communications is responsible for all communications that are presented to the customer by bill inserts, surveys, company website or social media avenues. Conservation programs are activities related to providing conservation programs and options to customers in order to manage their usage.

5.4 Engineering and Maintenance

The Engineering component of this function is responsible for distribution system planning, design and construction of plant in line with the applicable provincial requirements, development of design standards, specifications and equipment approvals and due diligence inspections. This component provides engineering support for servicing to customers, expansions for new developments such as sub-divisions, rebuild and enhancement projects, capital planning and the execution of capital projects and the development of an asset management program.

The Maintenance component relates to activities associated with the operation and maintenance of the natural gas distribution system. This includes both direct labour and non-capital material required to support both scheduled and reactive operation and maintenance events. Typically the company will have maintenance strategy, to minimize, as best as possible, reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions. The maintenance plan includes monitoring system reliability to ensure the maintenance strategy is effective and, if required, develops steps to adjust the maintenance plan to address system reliability issues. This effort is coordinated with capital project work so that where maintenance programs have identified matters that require capital investments, the capital spending priorities can be adjusted to address these matters.

5.5 Contracting Out

In order to manage a smaller distribution company it may be preferable to contract out certain functions and activities. If this option is being considered, generally the Customer Service and the Engineering and Maintenance functions can be contracted out to a service provider(s). In addition, the Gas Supply and Transportation and the Administration activities under the Finance function could also be contracted out. However, typically the other Finance activities remain within the company since these activities are critical to understanding the ongoing financial soundness of the company.

In order to obtain a service provider(s) to provide the required service(s) a Request for Proposal (RFP) process is normally used. This process would include the company sending out a RFP with requested services to potential service providers. The company would have list of criteria developed to evaluate the responses to the RFP. Once the responses are received they would be evaluated against the criteria. The service provider(s) that best meets the elements on the criteria list would usually be the chosen service provider(s). Contractual arrangements would need to be developed between the company and the service provider(s) to define the terms and conditions associated with the services being provided.

Chapter 6: Conclusions

The failure to provide natural gas service to the south Bruce region remains a deficiency in the overall provision of energy services in Ontario. Two options have recently been proposed to remedy this problem. The first provided by UNION envisages an extension of its existing system via two transmission lines, one from Dornoch and the other from Wingham that would meet the needs of the municipalities of the South Bruce region. The positive feature of this proposal is that natural gas would be provided to customers at the same rate as in other southwestern Ontario municipalities implying substantial savings to customers. The very serious drawback of the proposal is that the substantial incremental capital and other costs would have to be borne by the municipalities in the form of a contribution in aid of construction amounting some $85.7 million. So while there appear to be savings to natural gas consumers the incremental costs are simply shifted to the municipalities in another form. This amount is beyond the financial capacity of the municipalities.

An independent review of the UNION proposal concluded that it was technically feasible and that the estimated costs for the system that was proposed were not unreasonable. However, it also concluded that such an expensive system was impractical. It proposed that the transmission component of the UNION proposal be replaced with delivery of gas to the distribution facilities via compressed natural gas, which it judged entail far lower capital expenditures, although it had no worked out the details of this proposed alternative.

The second option proposed by NORTHERN consisted of a three-phased system which would start by an expansion of its existing Huron County facilities to connect the township of Huron-Kinloss, including industrial customers in the area, to the UNION system at Wingham. The second phase would connect the municipality of Arran-Elderslie and area industrials to the UNION system at Dornoch. The third phase would connect the first two phases and communities in between the two such as Tiverton, Kincardine and Point Clark. The total capital cost is some $27 million less than the UNION proposal. The phased approach is intended to provide the flexibility to connect industrial and selected commercial loads at an early stage of project development. A preliminary independent technical review of the NORTHERN proposal prepared by DR Quinn & Associates concluded that it did not have adequate information to reach conclusions on essential features of the NORTHERN system, including design, safety considerations and cost. This remains a major outstanding issue.

With respect to the financial aspects of the NORTHERN proposal the company providing the service would be a stand-alone entity and the cost of providing the service would be passed on to consumers in their rates. Initial estimates indicate that these rates would be substantially higher than those charges by UNION in the surrounding area but could still provide savings to customers under certain assumptions. These assumptions are that the predicted conversions to natural gas are actually realized, that the distribution company is prepared to receive lower than normal returns on capital for up to ten years and that capital expenditures are as forecast. This implies considerable risk to the distribution company that can be reduced by a lowering of capital expenditures. This could be accomplished through access to sources of funds from other levels of government.

In summary the contributions in aid of construction required by UNION are beyond the capacity of the municipalities making this option impractical. The NORTHERN option requires further independent analysis to ensure its technical feasibility. On the basis of existing information it would appear to involve considerable risk to the municipalities. These risks could be mitigated by the participation of other levels of government.

Appendices

Appendix A – Survey Methodology and Detailed Tables

Innovative Research Group Inc. (INNOVATIVE) was retained by Borden Ladner Gervais LLP on behalf of the municipalities of Kincardine, Huron-Kinloss and Arran-Elderslie to design and execute a survey to ascertain demand estimates for natural gas conversion among select residents and business establishment. INNOVATIVE is a full service national public opinion research firm with offices in Toronto and Vancouver.

Research Objectives

The goal of this research is to assess to assess the market potential for natural gas line connections among both residential homeowners and small-medium sized business establishments within a predetermined service area in the following three municipalities:

- Kincardine;
- Arran-Elderslie; and
- Huron-Kinloss

Survey results have been used to provide the required primary market potential data to complete the load forecast model which is required for the proponent's business case and subsequent Ontario Energy Board filings.

Key Findings

Overall, a plurality of residential property owners and a majority of business establishments in the study area say they are likely to convert their home or space heating to natural gas when it is made available.

When it comes to water heating, residential property owners are less likely to say they would convert when compared to home heating. However, approximately the same number of businesses would convert their water heating as would convert their space heating.

The key decision to convert appears to come down to conversion cost. The higher the conversion cost, the less interest in conversion among both residential property owners and businesses. This appears to outweigh benefits on longer term fuel cost savings.

Residential Findings

- 45% of respondents would likely or definitely convert home heating to natural gas if it were made available in their community. In terms of home heating, 24% of respondents currently have electric baseboard heating, 19% have propane forced air, 11% have oil forced air, 10% have electric forced air and 8% have boiler systems.

- In terms of residential water heaters, 36% of respondents say they would likely or definitely convert to natural gas if made available. Currently, most area water heaters are fueled by electricity (80%), while 12% use propane and 6% use oil.

The residential survey results are summarized in Exhibit 11.

Exhibit 11

Residential Home Heating Conversion by Community				
	Kincardine (n=342)	Huron-Kinloss (n=233)	Arran-Elderslie (n=178)	Total (n=753)
Household Sample Distribution	45%	31%	24%	100%
Home Heating Conversion				
Likely to Convert to NG*	**36%**	**42%**	**64%**	**45%**
Would Depend	**16%**	**21%**	**15%**	**18%**
Unlikely to Convert to NG**	**46%**	**34%**	**20%**	**36%**
Don't know	**2%**	**3%**	**1%**	**2%**
Occupancy Type				
Year Round	83%	68%	98%	82%
Seasonal (mostly summer)	11%	27%	1%	14%
Seasonal (throughout the year)	5%	5%	2%	4%
Type of Home Heating System				
Propane Forced Air	19%	19%	21%	19%
Oil Forced Air	7%	10%	20%	11%
Electric Forced Air	16%	5%	6%	10%
Electric Baseboard	28%	25%	12%	24%
Boiler	8%	7%	10%	8%
Other	16%	24%	21%	19%
Age of Home Heating System				
5 years or less	29%	28%	35%	30%
6 to 10 years	19%	24%	18%	20%
11 to 15 years	11%	13%	13%	12%
16 years or older	39%	32%	30%	35%

Business Findings

- Among business decision makers, 61% say they would likely or definitely convert space heating to natural gas if it were available. Currently, most area small-medium sized businesses use propane forced air (24%), followed by oil forced air and boiler systems (both 20%), and electric baseboard heating (15%).

- 62% would likely or definitely convert their water heating to natural gas. Most business water heaters are fueled by electricity (63%), followed by 24% propane and 6% oil.

The commercial survey results are summarized in Exhibit 12.

Exhibit 12

Business Heating Conversion by Community				
	Kincardine (n=69)	Huron-Kinloss (n=28)	Arran-Elderslie (n=36)	Total (n=134)
Sample Distribution	52%	21%	27%	100%
Conversion to Natural Gas				
Likely to Convert to NG*	**54%**	**48%**	**83%**	**61%**
Would Depend	**25%**	**24%**	**0%**	**18%**
Unlikely to Convert to NG**	**21%**	**28%**	**17%**	**21%**
Don't know	**0%**	**0%**	**0%**	**0%**
Age of business heating system				
10 years or less	51%	33%	58%	49%
11 years or older	46%	63%	42%	49%
Don't know	3%	3%	0%	2%
Type of system				
Propane Forced Air	28%	10%	29%	24%
Oil Forced Air	13%	21%	33%	20%
Electric Forced Air	6%	0%	4%	4%
Electric Baseboard	17%	19%	8%	15%
Boiler	19%	24%	18%	20%

- A detailed report on the full results of the Innovative survey can be found in Appendix A.

Methodology

Both surveys were conducted by telephone among residents and small-medium sized business establishments most likely to be in the service area, as identified by 6-digit postal code.

The residential survey was conducted from July 31st, 2014 to August 6th, 2014. Stratified random sampling was employed to ensure representativeness between the 3 municipalities in the service area and non-permanent residents as well. Results were also weighted according to Statistics Canada 2011 census data for municipality and household size. The total sample size is 753 which equates to a margin of error of ±3.6%, 19 times out of 20. Margins of error will be larger among sub-groups.

The business establishment survey was conducted from August 5th, 2014 to August 12th 2014. Businesses in the service area, excluding the government, MUSH, and large industrials, were randomly sampled from all 3 municipalities. To ensure the results are representative of the population, weights were applied for municipality and employment size according to Statistics Canada Business Register data. The total sample size is 156. The margin of error for a sample of this size, after a finite population correction, is ±7.4%, 19 times out of 20.

Note: tables and charts may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

Detailed Findings: Residential Survey

The following section details the findings from the survey conducted between July 31 and August 6, 2014 among 753 property owners.

Respondents qualified to complete the survey if they owned a residential property within the defined services area for the proposed natural gas distribution system expansion and if they were the person responsible for paying the energy bills of the property in question.

Conversions Analysis

Home Heating

Households across the proposed service area use a wide variety of home heating system, with electric baseboard being the most common (24%), followed by propane forced air (19%), oil forced air (11%), electric forced air (10%) and boiler-based systems. Other heating systems include heating systems include wood burning (11%), geothermal (4%), and mixed systems (3%).

Survey respondents were given a cost-benefit conversion scenario based on their heating system and heating fuel. This scenario included the estimated cost of conversion to a natural gas heating system and the estimated savings in terms of fuel costs. For example, if a home had electric baseboard heating the estimated upfront conversion cost of $10,000 (or financed at $101 per month over 10 years) was provided to the respondent along with the estimated fuel savings natural gas relative to electricity (over the past 5 years, electricity has been approximately twice the cost of natural gas). Respondents were then asked how likely they would be to convert to natural gas if it became available.

In terms of likelihood to convert, 45% of respondents said they would be likely to make the switch from their existing home heating system to natural gas systems when gas became available. 1-in-5 (18%) said it would depend (largely on the exact cost of conversion and feasibility assessment of converting their existing system), while 36% stated they would likely not convert. Those not likely to convert are skewed towards owners who use their property primarily in the summer, who have electric baseboard heating and residents in Kincardine.

When respondents said that whether or not they converted “depends”, they were asked to specify what is was that their decision depended on. Among this group, 64% said their decision would depend on the precise costs. A further 19% were concerned about feasibility on their property and 5% simply said they need more information or time to consider the decision.

When respondents said they were not likely to convert a plurality mentioned cost (33%), but a range of other issues were also important. Many were simply happy with their current system and didn’t see a need to change (25%), others didn’t see the need because of their age (9%) or seasonal use of the property (13%). Only some respondents (11%) were actively opposed to natural gas for safety, environmental or other reasons.

In terms of existing home heating systems, those with propane forced air (77%) are most likely to convert (which is the least costly form of conversion), while those with electric baseboard heating (30%) are least likely to convert (which is the most costly form of conversion).

Regionally, the highest conversion level is among respondents who own property in Arran-Elderslie (64%), followed by Huron-Kinloss (42%) and Kincardine (36%). Interestingly, compared to Kincardine and Huron-Kinloss, Arran-Elderslie has both significantly fewer seasonal residents and the lowest level of residential properties with electric baseboard heating. These two factors help explain part of why respondents with property in Arran-Elderslie are significantly more likely to convert to natural gas than respondents with residential property in Kincardine and Huron-Kinloss.

Table R1

Residential Home Heating Conversion by Community				
	Kincardine (n=342)	**Huron-Kinloss** (n=233)	**Arran-Elderslie (n=178)**	**Total (n=753)**
Household Sample Distribution	45%	31%	24%	100%
Home Heating Conversion				
Likely to Convert to NG*	**36%**	**42%**	**64%**	**45%**
Would Depend	**16%**	**21%**	**15%**	**18%**
Unlikely to Convert to NG**	**46%**	**34%**	**20%**	**36%**
Don't know	**2%**	**3%**	**1%**	**2%**
Occupancy Type				
Year Round	83%	68%	98%	82%
Seasonal (mostly summer)	11%	27%	1%	14%
Seasonal (throughout the year)	5%	5%	2%	4%
Type of Home Heating System				
Propane Forced Air	19%	19%	21%	19%
Oil Forced Air	7%	10%	20%	11%
Electric Forced Air	16%	5%	6%	10%
Electric Baseboard	28%	25%	12%	24%
Boiler	8%	7%	10%	8%
Other	16%	24%	21%	19%
Age of Home Heating System				
5 years or less	29%	28%	35%	30%
6 to 10 years	19%	24%	18%	20%
11 to 15 years	11%	13%	13%	12%
16 years or older	39%	32%	30%	35%

** "definitely" or "likely" to convert.*
*** "definitely would not" or "unlikely" to convert*

Table R2

Residential Home Heating Conversion by System						
	Propane Forced Air (n=146)	Oil Forced Air (n=81)	Electric Forced Air (n=77)	Electric Baseboard (n=178)	Boiler (n=62)	Other† (n=146)
Sample Distribution	19%	11%	10%	24%	8%	19%
Home Heating Conversion						
Likely to Convert to NG*	**77%**	**46%**	**40%**	**30%**	**45%**	**31%**
Would Depend	**11%**	**17%**	**22%**	**21%**	**18%**	**16%**
Unlikely to Convert to NG**	**10%**	**33%**	**36%**	**47%**	**35%**	**52%**
Don't know	**2%**	**4%**	**1%**	**1%**	**2%**	**1%**
Occupancy Type						
Year Round	88%	93%	86%	67%	89%	85%
Seasonal (mostly summer)	9%	6%	10%	23%	3%	12%
Seasonal (throughout the year)	3%	1%	4%	8%	7%	3%
Age of home heating system						
5 years or less	57%	22%	26%	11%	29%	30%
6 to 10 years	26%	22%	18%	10%	29%	23%
11 to 15 years	8%	31%	8%	6%	13%	12%
16 years or older	7%	24%	41%	69%	29%	31%

Note: don't know what type of heating system (8.4%) not shown

** "definitely" or "likely" to convert.*

*** "definitely would not" or "unlikely" to convert*

†Other heating systems include geothermal (3.6%), wood burning (10.5%), mixed heating systems (3.4%) and other (1.9%).

Table R3

Residential Home Heating Conversion by Occupancy Type				
	Year Round (n=619)	Seasonal (summer months) (n=102)	Seasonal (throughout the year) (n=32)	Total (n=753)
Sample Distribution	82%	14%	4%	100%
Home Heating Conversion				
Likely to Convert to NG*	**46%**	**35%**	**48%**	**45%**
Would Depend	**17%**	**23%**	**12%**	**18%**
Unlikely to Convert to NG**	**36%**	**42%**	**30%**	**36%**
Don't know	**1%**	**0%**	**9%**	**2%**
Type of Home Heating System				
Propane Forced Air	21%	13%	17%	19%
Oil Forced Air	12%	5%	3%	11%
Electric Forced Air	11%	8%	3%	10%
Electric Baseboard	19%	43%	47%	24%
Boiler	9%	3%	13%	8%
Other	20%	18%	13%	19%

** "definitely" or "likely" to convert.*
*** "definitely would not" or "unlikely" to convert*

Home Heating: Conversion Cost Sensitivity

Table R4

Residential Home Heating Conversion by Costs and Savings				
Cost to convert to natural gas:				
	$750-$1000 n=141	$5000-$6000* n=181	**$10,000*** n=430	**Total** n=753
% who would likely or definitely convert:				
Overall	79%	43%	34%	45%
By fuel cost ratio % who would likely or definitely convert:				
1.5 times*	79%	23%	36%	51%
2 times	N/A**	42%	30%	34%
2.5 times	N/A	48%	N/A	48%
By heating bill quartiles % who would likely or definitely convert:				
Lowest heating bills	78%	30%	31%	39%
Second bill quartile	78%	38%	40%	49%
Third bill quartile	74%	49%	45%	53%
Highest heating bills	91%	55%	39%	54%
Don't know bill amount	78%	36%	34%	34%

** Cost and savings ratio statements were modified in generic scenarios to "up to $5000-$6000", "up to $10,000" and "at least one-and-a-half times". They are combined here for ease of reading.*

*** In three cells the combination of cost and savings were not possible. Specifically the least expensive conversion is only possible on propane systems, and the most expensive only is given under either electrical or generic scenarios.*

In the case of home heating, it is informative to group options together by the costs and savings they result in. It is clear across-the-board that while cost and potential savings matter, cost matters more. The conversion cost here is the estimated cost of conversion respondents faced based on their reported type of hardware, and the fuel cost ratio is the estimated difference in cost between their existing fuel and natural gas.

The least expensive conversion, converting propane systems, has very high conversion rates at 79%. Among the middle category of conversion cost, conversions are less popular with less favourable fuel cost ratios (just 23%) compared to the more favourable ones (between 42 and 48%), but at no point do they approach levels similar to the less expensive conversions. Not surprisingly the most expensive conversions see the lowest interest, regardless of the fuel cost savings.

The cost scenario faced by the respondent was dependent on their answer to questions about their hardware and fuel type. In cases where respondents said that they had another type of hardware than those listed, they necessarily faced a generic cost scenario, equivalent to a full install with no existing equipment or ductwork. The full relationship between heating system and cost scenarios is laid out in the detailed methodology below.

Home Heating: Financing Offer

Before residential respondents were asked if they were likely to convert their heating systems to natural gas, they were presented with a financing scenario for the conversion costs and asked "if they chose to convert" whether they would likely finance the conversion.

One goal of the survey was to gauge interest in financing as an option for residents who want to convert to natural gas. In addition this question serves to educate respondents about the options they would have when deciding whether or not the conversion was worthwhile. Financing was presented as a monthly payment over a 10 year term with a 4% annual interest rate.

Table R5: Residential Home Heating Financing Options

	Kincardine (n=342)	Huron-Kinloss (n=233)	Arran-Elderslie (n=178)	Total (n=753)
Household Sample Distribution	45%	31%	24%	100%
Interest in Financing				
Finance the conversion	20%	22%	28%	23%
Pay the full cost up front	38%	41%	49%	42%
Not going to convert	34%	27%	13%	27%
Don't Know	8%	10%	11%	9%
Would finance: Conversion				
Likely to Convert to NG*	**46%**	**51%**	**61%**	**53%**
Would Depend	**19%**	**29%**	**27%**	**25%**
Unlikely to Convert to NG**	**34%**	**20%**	**13%**	**23%**
Don't know	**2%**	**0%**	**0%**	**1%**
Would pay up front: Conversion				
Likely to Convert to NG*	**62%**	**63%**	**80%**	**67%**
Would Depend	**23%**	**24%**	**11%**	**20%**
Unlikely to Convert to NG**	**14%**	**13%**	**9%**	**12%**
Don't know	**2%**	**0%**	**0%**	**1%**

Overall 23% of respondents said that they would take advantage of financing if they were to undertake the conversion to natural gas. Slightly less than twice as many (42%) said they would pay the full cost up front, while a quarter of the sample (27%) was adamant that they would not be converting either way (this was asked *before* the main conversion question).

Arran-Elderslie had the highest interest in financing (28%) and the fewest respondents who said they would not convert either way (just 13%). Kincardine has the highest number of respondents who made clear that they do not intend to convert either way (34%).

Those who would finance were slightly less likely to say they would actually convert (53%) compared to those prepared to pay up front (67%). This pattern held across all three municipalities, with residents in each area more likely to convert when they were prepared to pay up front.

Home Water Heating

The vast majority of water heaters in the sample region are run on electricity (80%), while small numbers heat their water with propane (12%) or oil (6%). A few respondents (1%) mentioned that their water is heated by their geothermal heating. When asked if their water heaters were owned or rented almost all respondents (91%) said that they owned their water heater compared to 8% who rent (a few respondents, less than 1%, said they didn't know if it was owned or rented).

Survey respondents were presented a conversion scenario for their water heater that was determined by the fuel type, and whether it was owned or rented. If respondents own their water heater, they were presented with costs to switch to natural gas depending if they simply need to convert their existing heater (propane) or purchase a new one (oil or electric; quoted as "about $2,500"). Respondents who rented were given a range of typical rental rates for natural gas heaters ("$13 to $24 per month"). Respondents were then asked how likely they would be to convert to natural gas if it became available.

Overall, 36% of respondents said they would "likely" or "definitely" to convert to a natural gas water heater if gas became available. 1-in-5 (18%) said it would depend, while 43% stated they would likely not convert. Those not likely to convert were typically respondents with oil or electric heaters, and from homes of 1 or 2 residents. Respondents who said it "depends" whether they switch to a natural gas water heater were asked to specify what it is was that their decision depends on. Among this group, 58% said their decision would depend on costs and 14% simply planned to wait until a replacement was needed before switching. A further 9% said they just needed to do more research, and the remaining respondents cited a wide range of concerns from age to the potential they would soon move.

When respondents said they were not likely to convert the most common answers were that the system was new, in good shape, or they were happy with it (39%), while 29% cited the issue of cost. Environmental concerns or a dislike of natural gas were an issue only for a small number of the respondents (10%).

Broken down by fuel type, those with propane are most likely to convert (72%), while those with the much more common electric water heaters, are about half as likely to convert (32%).

Across the three municipalities, the highest conversion level is among respondents who own property in Arran-Elderslie (44%), followed by Huron-Kinloss (34%) and Kincardine (34%). This is similar to the pattern seen in the analysis of home heating, and is likely for similar reasons. Interestingly, this holds true despite the fact that Arran-Elderslie also has half as many propane water heaters (which saw the highest interest in conversion) compared to the other municipalities.

Table R6

Residential Water Heater Conversion by Community				
	Kincardine (n=342)	Huron-Kinloss (n=233)	Arran-Elderslie (n=178)	Total (n=753)
Sample Distribution	45%	31%	24%	100%
Own vs. Rent				
Own Water Heater	88%	92%	96%	91%
Rent Water Heater	11%	8%	4%	8%
Water Heater Conversion				
Likely to Convert to NG*	**34%**	**34%**	**44%**	**36%**
Would Depend	**14%**	**21%**	**23%**	**18%**
Unlikely to Convert to NG**	**50%**	**42%**	**30%**	**43%**
Don’t know	**1%**	**3%**	**3%**	**2%**
Occupancy Type				
Year Round	83%	68%	98%	82%
Seasonal (mostly summer)	11%	27%	1%	14%
Seasonal (throughout the year)	5%	5%	2%	4%
Water Heat Fuel Type				

Propane	14%	12%	7%	12%
Oil	5%	8%	5%	6%
Electricity	79%	79%	85%	80%
Other	1%	1%	3%	2%
Age of water heater				
5 years or less	42%	39%	37%	40%
6 to 10 years	30%	28%	29%	29%
11 to 15 years	13%	12%	14%	13%
16 years or older	11%	12%	11%	12%

Note: don't know not shown
** "definitely" or "likely" to convert.*
*** "definitely would not" or "unlikely" to convert*

Table R7

Residential Water Heater Conversion by Fuel Type				
	Propane (n=87)	Oil (n=45)	Electricity (n=599)	Total† (n=753)
Sample Distribution	12%	6%	80%	100%
Own vs. Rent				
Own Water Heater	78%	78%	94%	91%
Rent Water Heater	21%	22%	6%	8%
Water Heater Conversion				
Likely to Convert to NG*	**72%**	**33%**	**32%**	**36%**
Would Depend	**15%**	**22%**	**19%**	**18%**
Unlikely to Convert to NG**	**11%**	**45%**	**46%**	**43%**
Don't know	**2%**	**0%**	**2%**	**2%**
Occupancy Type				
Year Round	91%	93%	80%	82%
Seasonal (mostly summer)	5%	2%	16%	14%
Seasonal (throughout the year)	4%	4%	4%	4%
Age of water heater				
5 years or less	64%	34%	37%	40%
6 to 10 years	26%	23%	30%	29%
11 to 15 years	4%	30%	13%	13%
16 to 25 years	2%	8%	8%	7%
Over 25 years	0%	0%	5%	4%

** "definitely" or "likely" to convert.*

*** "definitely would not" or "unlikely" to convert*

† Other/don't know for fuel type not shown (3%)

Table R8

Water Heater Conversion by Occupancy Type				
	Year Round (n=619)	Seasonal (summer months) (n=102)	Seasonal (throughout the year (n=32)	Total (n=753)
Sample Distribution	82%	14%	4%	100%
Water Heater Conversion				
Likely to Convert to NG*	**38%**	**27%**	**50%**	**36%**
Would Depend	**19%**	**19%**	**7%**	**18%**
Unlikely to Convert to NG**	**41%**	**54%**	**39%**	**43%**
Don't know	**2%**	**1%**	**4%**	**2%**

** "definitely" or "likely" to convert.*
*** "definitely would not" or "unlikely" to convert*

Natural Gas Perceptions

When we examine perceptions of natural gas, what becomes clear is that perceptions of natural gas clearly influence an individual's decision on conversion. Conversion rates are generally very high (between 55% and 63%) among those who agree with positive statements about gas and much lower otherwise.

However what is also clear is that most people agree with these statements to begin with. Levels of agreement are very high for every statement tested. Because of this, even though these perceptions clearly matter, their effect on overall conversion rates is relatively small. This is also seen when people who are not interested in converting are asked to explain why. Of those who were not interested in converting their home heating, only 11% mentioned problems with natural gas itself as the reason, and only 10% among those who did not want to convert their water heaters.

Table R9

Natural Gas Perceptions				
	Kincardine (n=342)	**Huron-Kinloss** (n=233)	**Arran-Elderslie (n=178)**	**Total (n=753)**
Sample Distribution	45%	31%	24%	100%
Natural Gas Perceptions				
NG is safe: % agree*	75%	87%	84%	80%
NG is reliable: % agree	81%	90%	90%	86%
NG is clean burning: % agree	79%	89%	88%	84%
NG is the best value: % agree	64%	75%	78%	71%

** "somewhat agree" or "strongly agree"*
*** Net likelihood is the % who say the message makes them more likely to convert minus the % who say less*
**** "definitely" or "likely" to convert either home heating or water heating.*

Table R10

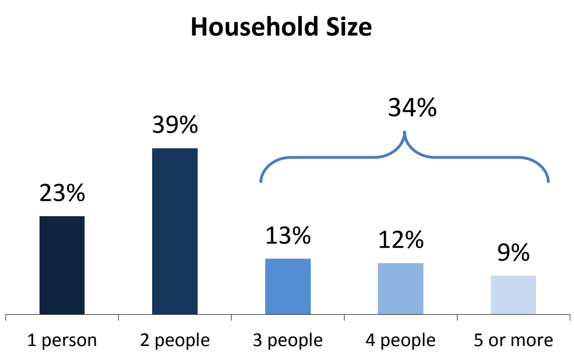
Effect of Natural Gas Perceptions on Conversion Rates				
	NG Safe	NG Reliable	NG Clean Burning	**NG Best Value**
% convert*				
Conversion among: Agree	58%	56%	55%	63%
Conversion among: Neutral	16%	9%	24%	20%
Conversion among: Disagree	9%	4%	10%	6%
Conversion among: Don't Know	15%	17%	20%	23%

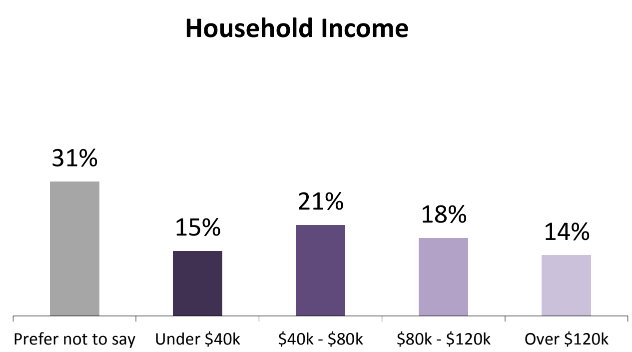
* *"definitely" or "likely" to convert either home heating or water heating*

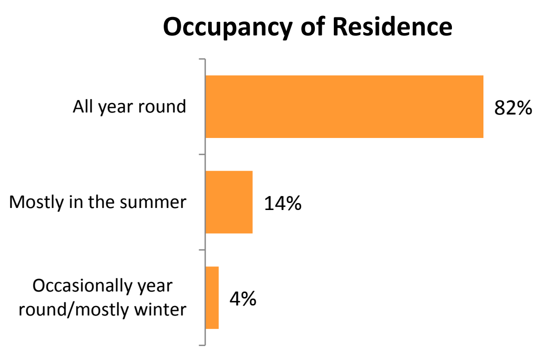
Residential Demographics

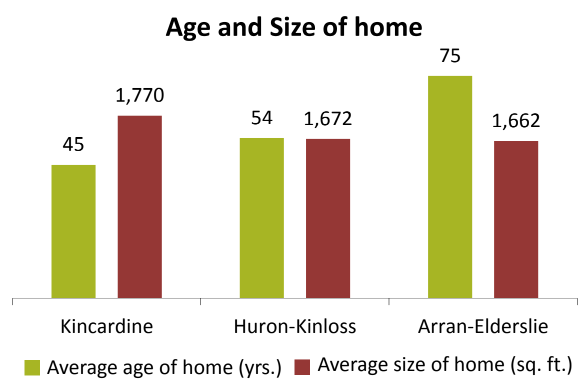
The charts below briefly detail the demographic breakdown of the sample. Most households in the region are one person (23%) or two (39%), and most are occupied all year round (82%). While many respondents prefer not to disclose their household income (31%), of those who do a small plurality (21%) make between $40,000 and $80,000 annually.

In terms of the age and size of homes in the sample area, the oldest homes are in Arran-Elderslie (an average of 75 years old), while the newest structures, on average, are in Kincardine (45 years old on average). Kincardine also has the largest homes, with an average size of 1,700 square feet. However this is only slightly larger than the average home size in Huron-Kinloss (1,672 square feet) and Arran-Elderslie (1,662 square feet).









Note: 'Refused' not shown

Detailed Findings: Business Establishment Survey

The following section details the findings from the business establishment survey.

Qualified survey respondents had to manage or oversee their business energy bills from establishments located in the sampling region as defined by their 6 digit postal code. Large industrial users, MUSH, and government establishments were not eligible for this survey and were also excluded from the sample.

The final sample of 156 business establishments was weighted according to municipality and employment size from Statistics Canada Business Register data, to accurately represent the distribution of business establishments in the region.

Business Conversions Analysis

Business Space Heating

Business space heating conversion questions were only asked of establishments who either owned their property or tenants who had sole or partial responsibility for the heating system at their establishment. The total sample size in this group is 134.

Table B1

Business Space Heating Responsibility by Community				
	Kincardine (n=84)	Huron-Kinloss (n=34)	Arran-Elderslie (n=38)	Total (n=156)
Sample Distribution	54%	22%	23%	100%
Property owners vs. tenants				
Owners	70%	80%	92%	77%
Tenants	30%	20%	8%	23%
Water heater responsibility*				
Tenant's sole responsibility	19%	17%	0%	18%
Landlord's sole responsibility	58%	67%	50%	59%
Jointly negotiated	19%	17%	50%	21%

** only asked of tenants*

Among business establishments with responsibility for their space heating systems the most common type of system used was a propane-forced air system (24%). Oil forced air (20%) and boiler systems (20%) were more common among business establishments than they were among residential households. Electric baseboard systems on the other hand were less common (15%) at business establishments than among residential households.

Interest in conversion is much higher among business establishments at 61%, while a further 18% say that it "would depend" and just 21% are unlikely to convert. Given that heating oil fueled systems (which are less common in businesses) are the most expensive conversion, this is not completely surprising. However when comparing between the same type of system we still see that businesses are more likely to convert than residential households across the board.

The most likely to convert are those with propane forced air (86%), while those with oil forced air are also highly likely to convert (79%). Electric forced air has the lowest rate of those who are likely to convert (20%), *but it is important to note the sample size of just 5 businesses in this case.* Otherwise the lowest conversion rate is among those with electric baseboard heating (35%).

Comparing across municipalities, establishments in Arran-Elderslie are the most likely to convert (83%) while Kincardine (54%) and Huron-Kinloss (49%) show lower levels of likelihood to convert. However in all 3 municipalities very few businesses say they are unlikely to convert altogether. Businesses that do not say they are likely to convert are just as likely to say it depends as to say they are unlikely.

When those businesses who said it depends were asked what their decision depends on the most common answer was the most common answer by far was cost (62%), while a further 10% were simply concerned with further assessing feasibility. Among those who would not likely convert, 28% were simply happy with their current system, while 24% thought the cost would be too high and 21% were opposed to natural gas or thought it might be dangerous.

Table B2

Business Heating Conversion by Community				
	Kincardine (n=69)	Huron-Kinloss (n=28)	Arran-Elderslie (n=36)	Total (n=134)
Sample Distribution	52%	21%	27%	100%
Conversion to Natural Gas				
Likely to Convert to NG*	**54%**	**48%**	**83%**	**61%**
Would Depend	**25%**	**24%**	**0%**	**18%**
Unlikely to Convert to NG**	**21%**	**28%**	**17%**	**21%**
Don’t know	**0%**	**0%**	**0%**	**0%**
Age of business heating system				
10 years or less	51%	33%	58%	49%
11 years or older	46%	63%	42%	49%
Don’t know	3%	3%	0%	2%
Type of system				
Propane Forced Air	28%	10%	29%	24%
Oil Forced Air	13%	21%	33%	20%
Electric Forced Air	6%	0%	4%	4%
Electric Baseboard	17%	19%	8%	15%
Boiler	19%	24%	18%	20%

Note: Only qualified decision-making respondents (n=134) were asked if they would convert their business heating system to natural gas.

** “definitely” or “likely” to convert.*

*** “definitely would not” or “unlikely” to convert.*

Table B3

Business Heating Conversion by System						
	Propane Forced Air (n=33)	Oil Forced Air (n=27)	Electric Forced Air (n=5)	Electric Baseboard (n=20)	Boiler (n=27)	Other† (n=15)
Sample Distribution	24%	20%	4%	15%	20%	11%
Conversion to Natural Gas						
Likely to Convert to NG*	**85%**	**81%**	**20%**	**37%**	**54%**	**38%**
Would Depend	**12%**	**8%**	**20%**	**26%**	**25%**	**19%**
Unlikely to Convert to NG**	**3%**	**12%**	**60%**	**37%**	**21%**	**44%**
Don't know	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Age of business heating system						
10 years or less	72%	46%	33%	36%	25%	81%
11 years or older	28%	54%	50%	59%	72%	19%
Don't know	0%	0%	17%	5%	4%	0%

Note: Only qualified decision-making respondents (n=134) were asked if they would convert their business heating system to natural gas. Don't know what type of heating system (5.2%) not shown.

†Other heating systems include geothermal (0.4%), wood burning (3.7%), mixed heating systems (3.2%) and other (4.0%).

** "definitely" or "likely" to convert.*

*** "definitely would not" or "unlikely" to convert.*

Business Water Heating

Water heating conversion questions were only asked of establishments who either owned their property or tenants who had sole or partial responsibility for the water heater at their establishment.

Table B4

Water Heater Responsibility by Community				
	Kincardine (n=84)	Huron-Kinloss (n=34)	Arran-Elderslie (n=38)	Total (n=156)
Sample Distribution	54%	22%	23%	100%
Property owners vs. tenants				
Owners	70%	80%	92%	77%
Tenants	30%	20%	8%	23%
Water heater responsibility*				
Tenant's sole responsibility	26%	20%	0%	23%
Landlord's sole responsibility	54%	20%	50%	47%
Jointly negotiated	18%	59%	50%	29%

** only asked of tenants*

The total sample size in this group is 139.

Similar to residential households, the majority of business establishments reported that they use electric water heaters (63%). Most remaining establishments used propane water heaters (24%), while only a few used oil fueled water heaters (6%) or alternatives (1%) such as wood. The profile of water heaters is similar across municipalities.

Similar to heating systems, interest in converting water heaters to natural is high among business establishments (62%). The likelihood to convert is highest in Arran-Elderslie (79%) and lower in Kincardine (55%) and Huron-Kinloss (60%). An additional 12% of establishments say that whether or not they convert depends, while only 24% say they would be unlikely to convert their water heater to natural gas if it becomes available.

The likelihood to convert is high among both propane (70%) and electric (61%) water heaters, but a greater number of establishments with electric heaters (30%) compared to propane (only 4%) are unlikely to convert. More establishments with propane heaters said that it would depend instead (26%).

Among those establishments that said it would depend whether they converted their water heating to natural gas, the most common concern was once again with cost (37%) while those who were not likely to convert were most likely to say that they were happy with their current system (43%) with cost being the second most common answer (20%), just 6% had safety or environmental concerns.

Table B5

Business Water Heater Conversion by Community				
	Kincardine (n=70)	Huron-Kinloss (n=33)	Arran-Elderslie (n=36)	Total (n=139)
Sample Distribution	50%	23%	26%	100%
Water heater Conversion				
Likely to Convert to NG*	55%	60%	79%	62%
Would Depend	16%	15%	3%	12%
Unlikely to Convert to NG**	28%	19%	18%	24%
Don't know	2%	7%	0%	2%
Own vs. Rent†				
Own Water Heater	91%	82%	89%	89%
Rent Water Heater	6%	0%	8%	5%
Water heater fuel				
Propane	25%	24%	23%	24%
Oil	0%	9%	7%	6%
Electricity	72%	49%	66%	63%
Other	0%	0%	3%	1%
Age of water heater				
5 years or less	41%	33%	23%	35%
6 to 10 years	24%	34%	27%	27%
11 to 15 years	15%	11%	12%	13%
16 to 25 years	7%	4%	23%	11%
Over 25 years	3%		4%	3%

* "definitely" or "likely" to convert.

** "definitely would not" or "unlikely" to convert

† Don't know not shown.

Table B6

Business Water Heater Conversion by Fuel Type			
	Propane (n=33)	Electricity (n=88)	Total (n=139)
Sample Distribution	23%	64%	100%
Water Heater Conversion			
Likely to Convert to NG*	**70%**	**61%**	**63%**
Would Depend	**26%**	**7%**	**12%**
Unlikely to Convert to NG**	**4%**	**30%**	**24%**
Don't know	**0%**	**3%**	**2%**
Own vs. Rent†			
Own Water Heater	88%	98%	89%
Rent Water Heater	11%	2%	5%
Age of home heating system			
5 years or less	34%	24%	23%
6 to 10 years	32%	24%	26%
11 to 15 years	20%	22%	22%
16 years or older	15%	28%	26%

Note: Other/don't know for fuel type not shown (n=10) and oil burning water heaters (n=8) not shown due to small sample size.

* "definitely" or "likely" to convert.

** "definitely would not" or "unlikely" to convert

† Don't know not shown.

Other Business Equipment

Questions about cooking appliances and other mechanical equipment first identified whether businesses use such equipment in their main line of work. Questions about conversion were only asked of establishments that use other equipment in their day-to-day business.

A total of 53 businesses said they use cooking appliances and 50 said they use other mechanical equipment.

Table B7

Other Equipment Conversion by Community		
	Cooking Appliances (n=53)	Mechanical Equipment (n=50)
Fuel Source		
Propane	34%	4%
Electricity*	66%	95%
Conversion: Propane	**n=18**	**n=2**
Likely to Convert to NG**	89%	0%
Would Depend	11%	50% (n=1)
Unlikely to Convert to NG***	0%	50% (n=1)
Conversion: Electrical	**n=35**	**n=48**
Likely to Convert to NG	35%	25%
Would Depend	32%	23%
Unlikely to Convert to NG	32%	52%
Frequency of use		
All the time	77%	74%
Sometimes	14%	20%
Rarely	8%	6%

** All fuel options were presented, only one respondent to the mechanical equipment question identified a category other than electrical or propane (wood)*

***"definitely" or "likely" to convert.*

**** "definitely would not" or "unlikely" to convert*

Among businesses with cooking appliances 34% use propane and 66% use electricity. On the other hand, businesses that said they used some other sort of mechanical equipment (e.g. pumps or large power tools) almost exclusively used electrical equipment (95%). Establishments were asked if they were likely to convert this equipment and were presented with fuel cost ratios specific to the fuel they used.

Interest in converting propane cooking equipment is very high (89%), with no business that has propane cooking equipment saying that it wouldn't at least depend (11%). Establishments with electrical cooking equipment were less likely to report that they would convert (35%), though a full 32% said that it would depend.

With regards to their electrical equipment 25% of establishments thought that they would convert it, while a further 23% said that it would depend. This is not surprising given that there is no guarantee this equipment would be possible or feasible to convert in all cases.

Additional Establishments

Business establishments were also asked about additional establishments (other than the establishment taking the survey) they have in the communities that are within the service area. Most businesses had only the one establishment that was taking the survey (69%).In general, businesses were more likely to have additional locations in communities in the same area as them. For example 35% of businesses in Huron-Kinloss had at least one more location in Ripley, and establishments in Arran-Ederslie only had additional locations in Chesley.

Of these additional establishments, most businesses thought that at least a few would convert to natural gas (69%), with the most common response being that all of them (56%) would likely convert.

Table B8

Other Establishments Conversion by Community				
	Kincardine (n=72)	Huron-Kinloss (n=32)	Arran-Elderslie (n=36)	Total† (n=141)
Sample Distribution	50%	23%	26%	100%
No additional establishments	60%	49%	65%	69%
Any additional establishments in:				
Kincardine*	16%	14%	0%	11%
Tiverton	6%	0%	0%	3%
Ripley	2%	35%	0%	9%
Lucknow	2%	17%	0%	5%
Paisley	9%	4%	0%	6%
Chesley	2%	0%	34%	9%
Number of additional establishments:**				
Only one	67%	41%	33%	50%
More than one	33%	41%	50%	40%
Likely conversion to natural gas				
All of them	65%	43%	56%	56%
Most of them	6%	11%	0%	6%
A few of them	3%	9%	12%	7%
None of them	20%	26%	12%	20%
Don't Know	7%	11%	19%	11%

**Including the lakeshore to Point Clark*
*** Only asked of those who had any additional establishments; don't know not shown (10%)*
† These questions were only asked of establishments who would have had some responsibility for converting any part of their operations to natural gas.

Methodology and Approach

This section details in full the methodological approach undertaken by Innovative to sampling the proposed service area and designing an appropriate survey instrument. It is important to note that sampling in a small geographical area presents unique methodological challenges. As the total proportion of a population that is included in a sample increases, the potential effects of non-response bias are increased as well. This makes proper sample design and weighting all the more imperative. However in small areas appropriate census data for weighting and sample design is not always available to the precise geographic level needed. As detailed below we make a number of assumptions to design stratified and weighted samples that represent the proposed service area as accurately as possible.

Defining the sampling region

As the purpose of these surveys was to identify interest in conversion to natural gas, it was important to develop a sampling region that matched, as closely as possible, the likely service area of the proposed distribution system. Innovative's understanding is that a proposed distribution system would provide service only in the communities listed in Table M1 below.

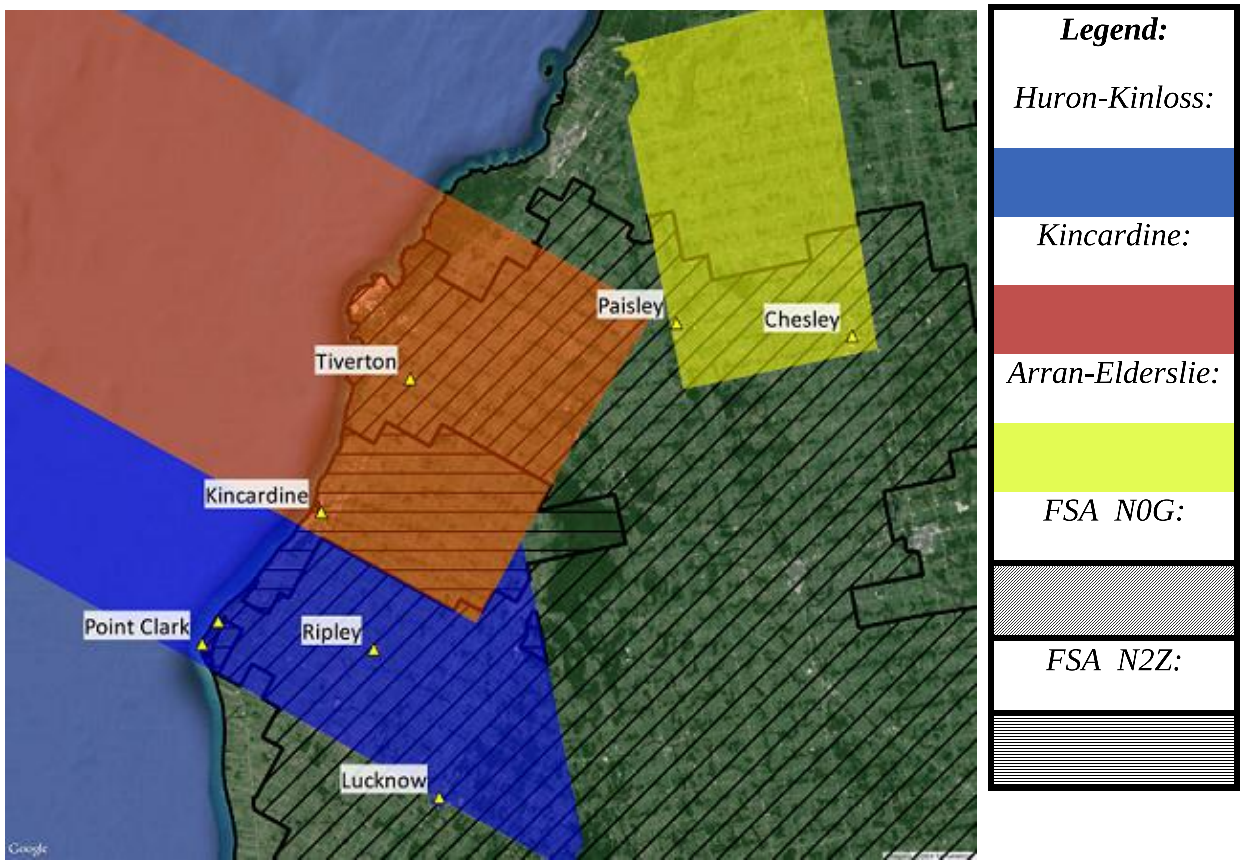
On this basis, a sampling region was defined consisting of a set of 6 digit postal codes. In both surveys only households, property owners or establishments within the sampling region, as defined by these postal codes, were eligible to take the survey. While this cannot be a perfect representation of the eventual service area, a region defined on the basis of postal code provides a largely effective method of limiting the sample to only potential customers. The sampling region is defined in Table M1.

Table M1

Definition of the Sampling Region	
Community/Area (*municipality in brackets*):	**Postal Code(s):**
Kincardine, and the Lakeshore to Point Clark *(Kincardine, Huron-Kinloss)*	All N2Z postal codes; except the rural postal codes of N2Z 2X4 and N2Z 2X5
Tiverton *(Kincardine)*	N0G 2T0
Ripley *(Huron-Kinloss)*	N0G 2R0
Lucknow *(Huron-Kinloss)*	N0G 2H0
Chesley *(Arran-Elderslie)*	N0G 1L0
Paisley *(Arran-Elderslie)*	N0G 2N0

Figure M1 details the layout of the region, including the municipal boundaries, communities, and forward sortation areas (FSA, defined by the first 3 digits of a postal code). This makes clear that the common approach of limiting sample by FSA would not have been sufficient to limit the properties and business establishments in the sample to the service area. It was on this basis that 6 digit postal code was used instead.

Figure M1
Map of the Region Showing Sampling Characteristics



The use of 6 digit postal codes, despite being much more precise than broader definitions of the sample area will nonetheless include some properties not in the service area. Rural properties, out of town and farther away from the distribution system are unlikely to be eligible to receive service, but may share a postal code with properties in town. In the N2Z FSA this was minimized to the extent possible by excluding postal codes judged largely to consist only of this type of property. In a rural FSA like N0G Canada Post assigns each rural community a single postal code. This will include rural properties surrounding the community but using only the postal codes for the specific communities in question will exclude all other properties in the FSA in any community not eligible for gas service.

Residential Survey: Sampling and Weights

The residential survey was conducted from July 31st, 2014 to August 6th, 2014. The goal of the residential survey was to provide a representative sample of homes in the area including non-permanent residents. Stratified random sampling was employed to ensure representativeness between the 3 municipalities in the service area and of non-permanent residents as well. The strata of permanent residents were weighted according to Statistics Canada 2011 census data for municipality and household size. The total sample size is 750 which equates to a margin of error of +/-3.6% 19 times out of 20. Margins of error will be larger among sub-groups.

Non-Permanent Residents

A stratum of non-permanent residents was included in the sample to ensure full and accurate representation of all owners of residential property in the region. For sampling purposes, non-permanent residents were defined as owners of a residential property that was within the sampling region, who received their property tax bill outside of the sampling region. An analysis of the municipal property tax rolls estimated the overall level of non-permanent residence at 14% of residential properties in the sampling region.

Non-permanent residents were identified from the municipal property tax rolls and a reverse phone-lookup based on name and address was used to collect phone numbers for the sample. When reached by telephone respondents were asked to verify that they were seasonal residents of the municipality, and if they were not the interview was not conducted.

This methodology to identify and contact non-permanent residents is preferable to the alternative: relying on attempts to contact non-permanent residents while they are visiting their property in the sampling region. Such an approach will not provide a fully representative sample of non-permanent residents because the probability of inclusion in the sample is conditional on unknown variables: how often and when the homeowner is present in the non-permanent residence. Using a stratified sampling approach with a separate sampling frame for non-permanent residents, despite the separate challenges it presents, was judged to be on balance the superior methodology.

However, in cases where the homeowner’s permanent residence is also nearby to the sampling region this approach does create some possibility for confusion as to what specific residence is being discussed. In order to minimize this to the extent possible, two steps were taken. First, as noted above, respondents were asked to confirm that they did in fact own a seasonal property in the municipality. Second, they were then read a brief statement explaining that the questions being asked pertained to the seasonal property and not their permanent residence. Identifying the property under discussion by its actual address may have reduced confusion further, but was not possible as typically the property’s location listed on the tax roll was a legal designation that would not be easily recognized by the homeowner (rather than the property's mailing address itself).

Permanent Residents

Permanent residents are residents whose primary residence is in the sampling region. These residents were sampled randomly from each municipality, with a stratum for each municipality, the relative size of which was defined by Statistics Canada household counts from the 2011 census, as shown in Table M2.

Table M2

Relative Sample Strata Sizes				
Municipality	StatsCan Number of Households (2011 National Household Survey)	StatsCan Relative number of households	Permanent Sample Strata	Non-Permanent Sample Stratum
Kincardine	4710	47%	40%	14%
Huron-Kinloss	2605	26%	22%	
Arran-Elderslie	2725	27%	23%	

Weighting

In order to accurately represent the population, within the strata of permanent residents results were weighted according to household size for each municipality. The full breakdown of weighting targets is shown in Table M3

Table M3

Overall Sample Weight Targets					
Municipality	Permanent Residents				Non-Permanent Residents
	1 Person	2 person	3 person	4+ person	
Kincardine	11%	16%	5%	8%	14%
Huron-Kinloss	5%	9%	3%	5%	
Arran-Elderslie	6%	9%	3%	5%	

Business Survey: Sampling and Weights

The business survey was conducted from August 5th, 2014 to August 12th 2014. Business establishments in the sampling region, excluding the government, MUSH, and large industrials (which were accounted for as part of a separate process as detailed elsewhere), were randomly sampled from all 3 municipalities. To ensure the results are representative of the population, weights were applied for municipality and employment size according to Statistics Canada Business Register data. The total sample size is 156. The margin of error for a sample of this size, after a finite population correction, is +/- 7.4% 19 times out of 20. Margins of error will be larger among sub-groups.

The weights were calculated according to Statistics Canada Business Register data for the 3 municipalities. This data provides, among other variables, establishment counts by NAICS code and employment size for each municipality. In order to estimate the correct distribution of establishment counts accurately as possible, large industrials, government, and MUCH sector establishments were filtered out by NAICS code. Because the establishment counts provided by Statistics Canada are at the level of the entire municipality, and the sampling region only covers the communities listed above, agricultural establishments (i.e. farms) were also excluded. While some farm properties immediately adjacent to the communities may be in the service area, and some non-agricultural businesses will lie outside of it, we believe this approach estimates as closely as possible the distribution of eligible establishments in the sampling region. The NAICS codes excluded are detailed in Table M4.

Table M4

Establishment Counts Excluded NAICS Codes	
Description	**Excluded NAICSCodes**
Agricultural establishments	Codes beginning with 1
Government establishments	Codes beginning with 9
Mining and Resource Extraction	Codes beginning with 211, 212
Energy generation and distribution	Codes 221111 to 221210
Pulp and Paper Mills	Codes 322111 to 322211
Waste collection and treatment	Codes beginning with 562
Elementary/Secondary Schools, Colleges, Universities	Codes 611110 to 611310
Ambulance Services and Hospitals	Codes 621911 to 622310

Based on these assumptions, the resulting distribution of establishment counts by Municipality and employment size that was calculated and used to weight the data is detailed in Table M5.

Table M5

Weight Targets by Employment Size and Municipality for Business Establishments				
Municipality	**1-4 Employees**	**5-9 Employees**	**10-19 Employees**	**20+ Employees**
Kincardine	12%	6%	3%	2%
Huron-Kinloss	15%	4%	2%	2%
Arran-Elderslie	26%	13%	7%	7%

Conversion Costs and Savings Estimates

In order to ensure that estimates of interest in conversion were as accurate as possible, respondents heard conversion scenarios specific to their current hardware and fuel source.

Conversion Costs

When discussing conversion costs, residential respondents were given numbers that were based on the estimates derived by UNION Gas for its 2012 feasibility study of the same region. One change was made to the cost estimates used by the previous study. UNION Gas identified the cost of converting a boiler system for heating as equivalent to the cost of converting an electric baseboard system. However our assessment is that installation of a natural gas boiler is most closely equivalent instead to installation of a natural gas furnace. As such, these estimates were adjusted accordingly.

For residential customers a financing option was also discussed. This is in keeping with the fact that it is common practice to finance potentially expensive home renovations with a bank loan or line of credit. Additionally, the municipalities advised that they may consider exploring the creation of a vehicle to provide financing to potential gas customers directly. The finance costs listed were given as monthly payments with a 10 year term and a 4% annual interest rate.

Because business establishment's cost of converting varies to a much greater degree according to the size of their establishment, providing meaningful cost estimates is more problematic. Our approach was to provide an explanation of the main cost driver involved in the conversion so that at the very least the relative differences in the magnitude of the conversion project would be apparent. The conversion costs given for each type of hardware and fuel combination are listed in Table M6.

In cases where the respondent did not know the type of heating system or fuel used, or used a system such as a wood stove or geothermal heat the generic cost scenario presented was equivalent to that of installing a full system from no existing base. All respondents who indicated they didn't know which type of system their house used were asked to specify, these open-ended responses were coded after the fact, and for the purposes of analysis these respondents are counted under the actual system they use. However the cost estimate they faced in the survey remains the generic one.

Table M7 Cost Estimates for Hardware, Fuel, and Respondent Types

	Residential Households		Business Establishments
Heating System	**Total Cost**	**Finance Cost (Monthly Payment)**	**Cost Driver**
Propane Forced Air	$750-$1,000	$8 to $10	Make only a small modification to your furnace
Oil Forced Air	$5,000-$6,000	$51 to $61	Replace your furnace but not your ductwork
Electric Forced Air	$5,000-$6,000	$51 to $61	Replace your furnace but not your ductwork
Propane Boiler	$750-$1,000	$8 to $10	Make only a small modification to your hot water boiler
Oil Boiler	$5,000-$6,000	$51 to $61	Replace your hot water boiler but not your ductwork
Electric Boiler	$5,000-$6,000	$51 to $61	Replace your hot water boiler but not your ductwork
Forced Air/Boiler, Don't Know Fuel	Up to $5,000-$6,000	Up to $51 to $61	Replace your hot water boiler but not your ductwork
Electric Baseboard	$10,000	$101	Install ductwork and purchase a furnace
Other System	Up to $10,000	Up to $101	Install ductwork and purchase a furnace
Water Heater	**Total Cost**		**Cost Driver**
Propane Water Heater (owned)	If a liner is needed, up to $1,000		If a liner is needed, that has a small cost.
Oil Water Heater (owned)	$2,500		Converting your water heating to natural gas would mean purchasing and installing a natural

		gas water heater.
Electric Water Heater (owned)	$2,500	Converting your water heating to natural gas would mean purchasing and installing a natural gas water heater.
Rented Water Heater	$13 to $24 per month	Typical monthly rental rates are comparable to those for other kinds of water heaters

Savings from Conversion

Respondents were also presented with potential savings from converting to natural gas. Savings were specific to the fuel type they were using. They were expressed in the form of a ratio of costs between the fuel type and natural gas. Ratios were calculated to represent the 5 year historical average cost ratio based on the amount of fuel required for equivalent output of heat energy. The ratios used in the survey were the low-end estimates from these calculations, in order to represent a conservative view of future prices and not overstate the savings from conversion. Because businesses achieve greater economies of scale from natural gas than they do from other fuel sources, these ratios represent a low-end estimate for business establishments (who are more likely to be larger users), and were expressed as such, being prefaced by “at least” in the business survey to reflect this. The ratios are detailed in Table M8 below.

Table M8

Fuel Cost Ratios for Homes and Business Establishments	
Fuel	**Cost Ratio**
Propane	One and a half times the cost of natural gas
Electricity	Twice the cost of natural gas
Heating Oil	Two and a half times the cost of natural gas
Don’t Know/Other	At least one and a half times the cost of natural gas

Appendix B - Preliminary Technical Analysis of the Northern Cross Proposal Prepared by DR Quinn & Associates Inc.

<u>Background & Scope</u>

DR Quinn & Associates ("DRQ") was retained by Borden Ladner Gervais LLP to review slide deck materials provided by Northern Cross Energy Limited ("NORTHERN") pertaining to its proposal to bring natural gas distribution services to the municipalities. DRQ was also asked to perform an initial technical risk assessment of the NORTHERN proposal based on the materials provided.. Given the high-level nature of the information contained in the NORTHERN proposal, the following summary should be considered as preliminary which has been supplemented by past experience and a preliminary discussions with NORTHERN's consultant. A detailed and comprehensive technical risk assessment can be carried out after additional detailed information is provided by NORTHERN.

<u>Risk Assessment of Competing Natural Gas Proposal Analysis</u>

One of the most striking features in reviewing the proposal is NORTHERN 's assertion that they can build a new natural gas distribution system at approximately two-thirds the cost of Union Gas. We are advised that the significant distinguishing feature of the NORTHERN proposal (when compared to Union Gas), is NORTHERN's approach avoids the need to construct new <u>transmission</u> pipeline. In other words, the NORTHERN proposal provides gas distribution augmented by compression and storage in a manner that avoids any new gas transmission infrastructure.

Whether a distribution system can be built, operated and maintained at the cost contemplated by NORTHERN in fact, is a critical factor in assessing the Northern proposal. Discussion concerning the economic feasibility of NORTHERN and Union Gas is considered elsewhere in this report. However, the total costs associated with the NORTHERN proposal need to be confirmed and verified.

<u>Safety Standards</u>

The natural gas industry has an enviable safety record owing to its strict adherence to codes and standards given the potential explosive nature of it delivered commodity. Ontario natural gas utilities are safety-regulated by the Technical Standards and Safety Authority ("TSSA"). The TSSA adopts the use of the Canadian standards for Oil and Gas the CSA Z662. Any natural gas distribution system would need to meet these minimum standards.

In addition, the TSSA ensures that operating utilities have documented policies and practices and integrity management programs. An established utility, like Union Gas, has created the documents and has developed programs to maintain the safety and integrity of its systems. A newly established utility would need to establish similar requirements to demonstrate its capability to operate the system safely to the TSSA. These requirements would include preparing Manuals for Emergency, Operations and Maintenance and evidence that staff and contractors are equipped to meet the standards. In addition, the new utility would need to prepare and file a Pipeline Integrity Management Program with the TSSA. NORTHERN stated that the costs for meeting these requirements were embedded in their overall cost estimate but acknowledged that they were not specifically identified.

<u>Distribution System Design</u>

Union Gas, Enbridge Gas Distribution and even smaller municipally-owned natural gas utilities like Kitchener establish a standard distribution maximum operating pressure of 420kPa. Using this standard allows all customer facilities to be designed using this maximum pressure standard including the customer pressure safety devices.

The NORTHERN proposal appears to be premised on using a 552kPa Maximum Operating Pressure ("MOP") for distribution. In our preliminary discussion with NORTHERN, their representative indicated that the pipeline may not operate at that level. However, if the pipeline design is going to rely on the 552 kPa MOP, then all components attached to the system must be rated and tested for this pressure. The higher operating pressure will require the use of a more specialized customer connection. While this connection could be designed to be no less safe than the standard utility connection, sourcing the more specialized components for the customer connection would tend to increase the cost of the individual customer sites as local gas product distributors would need to source the non-standard equipment. This approach would bind the operating company to continue to source this equipment as customer conversions occur.

Beyond the operating pressure issue, the proposal also plans for the use of High Density Polyethylene (“HDPE”) pipe for moving the gas between load centres. While this approach may meet the design needs of the system, it limits the maximum operating pressure. This restriction limits the ability of the system operator to increase the pressure in the future to meet unforeseen load increases. This restriction was acknowledged in discussion with NORTHERN. Without more information on the expected hourly demands from the load centres, it is not possible at this time to perform any assessment of the piping system and its scalability to meet future needs. It is recommended the design sizing of the entire system be understood to assess the appropriateness of the proposed system including flexibility to add potential customers in the future.

<u>Natural Gas Storage</u>

Natural gas storage is a very valuable asset to have in a natural gas pipeline system. Having the ability to store gas in the months of lower demand for use in periods of high demand can provide economic benefit to the operator and the system customers. However, to be able to leverage the value of the gas reservoir, the gas needs to be accessible to customers during time of peak utilization. This means the well has to have the characteristic of deliverability so that the gas can be extracted at a sufficient rate to meet the requirements of the system. The NORTHERN proposal did not have provide details about the capabilities of the proposed storage pools at this time, however, NORTHERN indicated verbally that the wells would have ample capability. It is recommended that these aspects of the proposed storage system including the associated compression be evaluated further.

One other aspect of the gas storage issue that requires further evaluation and review is the distance between the storage in the south part of the pipeline network and the expected main load centres in the northern most reaches of the service territory. Assuming that the storage deliverability and compression can meet the expected peak needs, the pipeline network would still need to transmit this gas to the ends of the system. With the aforementioned limitation of an operating pressure of 933/993 kPa, it is recommended that the ability to get stored gas to load centres ought to be evaluated to ensure the value of the storage asset can be optimized.

Preliminary Conclusion & Recommended Follow-Up

Designing and operating a new natural gas distribution system requires specialized knowledge and expertise. Much more detailed information is required with respect to the NORTHERN proposal in order for a comprehensive technical assessment to be carried out.

Therefore, we strongly recommend an independent, experienced, third-party review of the following components of the NORTHERN proposal as the additional information as it is made available:

- Review of the pipe network design including:
  - Hourly load assumptions.
  - Pipeline sizing.
  - Resulting incremental capacity for growth.
  - Confirmation of all required connection and operational-related costs to link the NORTHERN proposal into the Union Gas network.

- Assessment of unit costs underpinning the infrastructure estimates:
  - Storage development and compression.
  - High pressure mains between gas sources and communities.
  - Distribution network mains.
  - Customer attachment and service costs at design operating pressure.

- Review of the estimation of costs for creating and documenting safety standards.

Appendix C – Pro-forma Financial Projections

Exhibit C – 1
Base Case
Adjusted Union Demand Projections

Income Statement										
Revenue										
Service Revenue	3,003,428	5,061,876	6,130,939	6,636,894	6,957,187	7,203,726	7,444,141	7,655,494	7,872,777	8,096,159
Residential	1,338,181	2,724,615	3,480,155	3,824,491	4,041,824	4,201,969	4,357,451	4,494,056	4,634,600	4,779,192
Commercial	526,474	1,181,406	1,477,592	1,621,612	1,706,711	1,774,974	1,841,506	1,897,576	1,955,357	2,014,905
Industrial	1,138,774	1,155,855	1,173,193	1,190,791	1,208,653	1,226,782	1,245,184	1,263,862	1,282,820	1,302,062
Commodity Revenue	4,875,988	6,403,061	7,126,222	7,446,320	7,590,092	7,692,591	7,784,643	7,847,063	7,910,287	7,974,328
Other Income	0	0	0	0	0	0	0	0	0	0
Costs										
Cost of Gas	4,875,988	6,403,061	7,126,222	7,446,320	7,590,092	7,692,591	7,784,643	7,847,063	7,910,287	7,974,328
OM&A	1,360,489	1,786,571	1,988,345	2,077,659	2,117,774	2,146,373	2,172,057	2,189,473	2,207,114	2,224,982
EBITD	1,642,939	3,275,305	4,142,594	4,559,235	4,839,413	5,057,353	5,272,084	5,466,020	5,665,663	5,871,176
Depreciation	2,457,574	2,457,574	2,420,710	2,384,400	2,348,634	2,313,404	2,301,837	2,313,346	2,324,913	2,336,538
Property taxes	221,144	225,788	230,868	236,063	241,374	246,805	252,359	258,037	263,842	269,779
EBIT	-1,035,780	591,943	1,491,015	1,938,772	2,249,405	2,497,143	2,717,889	2,894,637	3,076,907	3,264,860
Interest	1,974,246	1,839,667	1,839,667	1,874,882	1,910,097	1,945,312	1,945,312	1,945,312	1,945,312	1,945,312
Pre-tax Income	-3,010,026	-1,247,724	-348,652	63,890	339,308	551,831	772,577	949,326	1,131,595	1,319,548
Income taxes	0	0	0	0	0	0	0	0	0	0
Post-tax Net Income	-3,010,026	-1,247,724	-348,652	63,890	339,308	551,831	772,577	949,326	1,131,595	1,319,548

Exhibit C-2
Base Case Balance Sheet

Balance Sheet										
Current Assets										
Cash and investments	186,280	-8,198	1,430,597	3,250,400	5,261,439	6,005,799	6,256,397	6,637,913	7,154,479	7,810,349
Other	330,709	330,709	330,709	330,709	330,709	330,709	330,709	330,709	330,709	330,709
Long-term Assets										
Property and Equipment (Cost)	70,216,400	71,620,728	73,003,991	74,366,505	75,708,582	77,691,500	80,322,171	82,965,995	85,623,039	88,293,367
Less: Accumulated Depreciation	0	2,457,574	4,878,284	7,262,684	9,611,318	11,924,722	14,226,559	16,539,906	18,864,819	21,201,357
Net Book Value of Fixed Assets	70,216,400	69,163,154	68,125,707	67,103,821	66,097,264	65,766,777	66,095,611	66,426,089	66,758,220	67,092,011
Other	24,099	24,099	24,099	24,099	24,099	24,099	24,099	24,099	24,099	24,099
Total Assets	70,757,488	69,509,765	69,911,112	70,709,030	71,713,511	72,127,385	72,706,817	73,418,811	74,267,508	75,257,169
Liabilities										
Operating	541,088	541,088	541,088	541,088	541,088	541,088	541,088	541,088	541,088	541,088
Other liabilities	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089	2,949,089
Long-term debt	39,180,751	39,180,751	39,930,751	40,680,751	41,430,751	41,430,751	41,430,751	41,430,751	41,430,751	41,430,751
Equity										
Common Equity	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560	28,086,560
Accumulated surplus	0	-1,247,724	-1,596,376	-1,548,458	-1,293,977	-880,104	-300,671	411,323	1,260,019	2,249,680
Contributed Capital	0	0	0	0	0	0	0	0	0	0
Total Liabilities & Equity	70,757,488	69,509,765	69,911,112	70,709,030	71,713,511	72,127,385	72,706,817	73,418,811	74,267,508	75,257,169

Exhibit C – 3

Base Case

Elenchus Demand Projections

Income Statement										
Revenue										
Service Revenue	2,396,926	5,051,654	6,255,391	6,566,599	6,885,702	7,212,342	7,403,748	7,514,804	7,627,526	7,741,939
Residential	1,034,393	2,210,489	2,673,382	2,876,678	3,084,886	3,298,693	3,405,444	3,456,525	3,508,373	3,560,999
Commercial	418,737	970,599	1,227,901	1,300,502	1,375,556	1,452,010	1,499,741	1,522,237	1,545,070	1,568,246
Industrial	943,795	1,870,567	2,354,108	2,389,419	2,425,261	2,461,639	2,498,564	2,536,042	2,574,083	2,612,694
Commodity Revenue	4,065,840	8,557,920	10,733,040	10,875,120	11,017,200	11,159,040	11,230,320	11,230,320	11,230,320	11,230,320
Other Income	0	0	0	0	0	0	0	0	0	0
Costs										
Cost of Gas	4,065,840	8,557,920	10,733,040	10,875,120	11,017,200	11,159,040	11,230,320	11,230,320	11,230,320	11,230,320
OM&A	1,134,443	2,387,815	2,994,713	3,034,356	3,073,999	3,113,575	3,133,464	3,133,464	3,133,464	3,133,464
EBITD	1,262,482	2,663,839	3,260,677	3,532,243	3,811,703	4,098,767	4,270,285	4,381,341	4,494,063	4,608,476
Depreciation	2,457,574	2,457,574	2,420,710	2,384,400	2,348,634	2,313,404	2,301,837	2,313,346	2,324,913	2,336,538
Property taxes	184,401	188,273	192,510	196,841	201,270	205,799	210,429	215,164	220,005	224,955
EBIT	-1,379,493	17,991	647,457	951,002	1,261,799	1,579,564	1,758,018	1,852,831	1,949,145	2,046,983
Interest	1,974,246	1,839,667	1,839,667	1,874,882	1,910,097	1,945,312	1,945,312	1,945,312	1,945,312	1,945,312
Pre-tax Income	-3,353,739	-1,821,675	-1,192,210	-923,880	-648,298	-365,748	-187,293	-92,481	3,833	101,671
Income taxes	0	0	0	0	0	0	0	0	0	0
Post-tax Net Income	-3,353,739	-1,821,675	-1,192,210	-923,880	-648,298	-365,748	-187,293	-92,481	3,833	101,671

Exhibit C – 4

Risk Analysis

High Capital Spending Case

Income Statement										
Revenue										
Service Revenue	3,003,428	5,061,876	6,130,939	6,636,894	6,957,187	7,203,726	7,444,141	7,655,494	7,872,777	8,096,159
Residential	1,338,181	2,724,615	3,480,155	3,824,491	4,041,824	4,201,969	4,357,451	4,494,056	4,634,600	4,779,192
Commercial	526,474	1,181,406	1,477,592	1,621,612	1,706,711	1,774,974	1,841,506	1,897,576	1,955,357	2,014,905
Industrial	1,138,774	1,155,855	1,173,193	1,190,791	1,208,653	1,226,782	1,245,184	1,263,862	1,282,820	1,302,062
Commodity Revenue	5,597,228	7,350,181	8,180,309	8,547,754	8,712,793	8,830,453	8,936,121	9,007,774	9,080,350	9,153,864
Other Income	0	0	0	0	0	0	0	0	0	0
Costs										
Cost of Gas	5,597,228	7,350,181	8,180,309	8,547,754	8,712,793	8,830,453	8,936,121	9,007,774	9,080,350	9,153,864
OM&A	1,360,489	1,786,571	1,988,345	2,077,659	2,117,774	2,146,373	2,172,057	2,189,473	2,207,114	2,224,982
EBITD	1,642,939	3,275,305	4,142,594	4,559,235	4,839,413	5,057,353	5,272,084	5,466,020	5,665,663	5,871,176
Depreciation	2,820,300	2,820,300	2,777,995	2,736,326	2,695,281	2,654,851	2,641,577	2,654,785	2,668,059	2,681,399
Property taxes	221,144	225,788	230,868	236,063	241,374	246,805	252,359	258,037	263,842	269,779
EBIT	-1,398,506	229,217	1,133,730	1,586,847	1,902,758	2,155,696	2,378,149	2,553,199	2,733,761	2,919,998
Interest	2,265,636	2,265,636	2,265,636	2,302,236	2,338,836	2,375,436	2,375,436	2,375,436	2,375,436	2,375,436
Pre-tax Income	-3,664,141	-2,036,419	-1,131,906	-715,389	-436,078	-219,740	2,713	177,763	358,326	544,563
Income taxes	0	0	0	0	0	0	0	0	0	0
Post-tax Net Income	-3,664,141	-2,036,419	-1,131,906	-715,389	-436,078	-219,740	2,713	177,763	358,326	544,563

Exhibit C – 5

Risk Analysis

Lower Demand Case

Income Statement										
Revenue										
Service Revenue	2,679,220	4,486,519	5,427,875	5,869,772	6,154,205	6,371,083	6,582,966	6,770,360	6,963,017	7,161,087
Residential	1,236,690	2,467,046	3,138,656	3,441,789	3,637,277	3,779,757	3,918,456	4,041,299	4,167,683	4,297,708
Commercial	461,172	1,023,395	1,278,200	1,401,799	1,475,351	1,534,125	1,591,451	1,639,907	1,689,842	1,741,304
Industrial	981,358	996,078	1,011,019	1,026,184	1,041,577	1,057,201	1,073,059	1,089,155	1,105,492	1,122,074
Commodity Revenue	4,757,644	6,247,654	6,953,262	7,265,591	7,405,874	7,505,885	7,596,703	7,656,608	7,718,298	7,780,784
Other Income	0	0	0	0	0	0	0	0	0	0
Costs										
Cost of Gas	4,757,644	6,247,654	6,953,262	7,265,591	7,405,874	7,505,885	7,596,703	7,656,608	7,718,298	7,780,784
OM&A	1,156,416	1,518,585	1,690,094	1,766,010	1,800,108	1,824,417	1,846,248	1,861,052	1,876,047	1,891,235
EBITD	1,522,803	2,967,934	3,737,782	4,103,763	4,354,097	4,546,666	4,736,717	4,909,308	5,086,971	5,269,852
Depreciation	2,457,574	2,457,574	2,420,710	2,384,400	2,348,634	2,313,404	2,301,837	2,313,346	2,324,913	2,336,538
Property taxes	187,973	191,920	196,238	200,654	205,168	209,785	214,505	219,331	224,266	229,312
EBIT	-1,122,743	318,440	1,120,833	1,518,709	1,800,295	2,023,477	2,220,375	2,376,630	2,537,791	2,704,002
Interest	1,974,246	1,839,667	1,839,667	1,874,882	1,910,097	1,945,312	1,945,312	1,945,312	1,945,312	1,945,312
Pre-tax Income	-3,096,990	-1,521,226	-718,834	-356,173	-109,802	78,165	275,063	431,319	592,479	758,690
Income taxes	0	0	0	0	0	0	0	0	0	0
Post-tax Net Income	-3,096,990	-1,521,226	-718,834	-356,173	-109,802	78,165	275,063	431,319	592,479	758,690

Appendix D – Ontario Policy on Expanding Natural Gas Services

The Ontario Government's latest Long Term Energy Plan (the "LTEP"), issued in December 2013[2], considers the current state of Ontario's energy supply and identifies areas on which the government intends to focus in the coming years. Much of the LTEP focuses on electricity (including, among other matters, supply, transmission and regional planning for infrastructure) and conservation-related matters, but the LTEP also speaks to oil and natural gas considerations.

At page 75 of the LTEP, the Government states:

"Ontario wants to make sure communities have access to natural gas to take advantage of the changing North American market and low prices. Natural gas heating is significantly less expensive than that provided by electricity or heating oil. There is also increasing interest in the use of compressed or liquid natural gas as a transportation fuel for corporate car and truck fleets, to reduce costs and the emissions of greenhouse gases.

The quality of life and economic prosperity of Ontario depends on having secure access to competitively priced natural gas and an equally competitively priced natural gas transmission and distribution system."

At page 77, in its summary of the key points in the brief Oil and Natural Gas chapter of the LTEP, the Government goes on to state:

"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."

Not long after the LTEP was issued, the province entered into the spring election campaign. As part of its platform, the Ontario Liberal Party pledged to expand access to natural gas supplies, with $200 million over two years for a Natural Gas Access Loan and $15 million in each of 2015-16 and 2016-17 for a Natural Gas Economic Development Grant.

The announcement of these programs appears to have created a significant amount of interest in communities that do not currently have access to natural gas, among Ontario farmers, and with natural gas utilities. In a June 24, 2014 speech to the Economic Club of Canada in Toronto, Greg Ebel, the Chairman, President and CEO of Spectra Energy, the parent corporation of UNION Gas, indicated that he was "delighted to see the Liberal Party recognize the value of natural gas in its election platform" and praised the loan and grant programs as "great initiatives that will help municipalities, First Nations and other consumers access competitive and affordable natural gas". However, at this time we are not aware of further details regarding these proposed programs at this time. The Municipalities should meet with Ministry of Energy

[2] Available at <http://www.energy.gov.on.ca/docs/LTEP_2013_English_WEB.pdf>

officials to obtain the latest information and details concerning how the Province intends to implement its policy in the context of the Southern Bruce gas initiative.

Appendix E – Ontario Premier's 2014 Mandate Letter to the Minister of Energy

The Premier
of Ontario

La premiere ministre de
l'Ontario

Legislative Building
Queen's Park
Toronto, Ontario
M7A 1A1

Edifice de l'Assemblee legislative
Queen's Park

Toronto (Ontario)

M7A 1A1

September 25, 2014

The Honourable Bob Chiarelli
Minister of Energy
900 Bay Street
Fourth Floor, Hearst Block
Toronto, Ontario
M7A 2E1

Dear Minister Chiarelli:

I am honoured to welcome you back to your role as Minister of Energy. We have a strong Cabinet in place, and I am confident that together we will build Ontario up, create new opportunities and champion a secure future for people across our province. The people of Ontario have entrusted their government to be a force for good, and we will reward that trust by working every day in the best interests of every person in this province.

As we implement a balanced and comprehensive plan for Ontario, we will lead from the activist centre. We will place emphasis on partnerships with businesses, communities and people to help foster continued economic growth and make a positive impact on the lives of every Ontarian. This collaborative approach will shape all the work we do. It will ensure we engage people on the issues that matter the most to them, and that we implement meaningful solutions to our shared challenges.

Our government's most recent Speech from the Throne outlined a number of key priorities that will guide your work as minister. Growing the economy and helping to create good jobs are fundamental to building more opportunity and security, now and in the future. That critical priority is supported by strategic investments in the talent and skills of our people, from childhood to retirement. It is supported through the building of modem infrastructure, transit and a seamless transportation network. It is supported by a dynamic business climate that thrives on innovation, creativity and partnerships to foster greater prosperity. And it is reflected across all of our government, in every area, and will extensively inform our programs and policies.

As we move forward with our plan to grow the economy and create jobs, we will do so through the lens of fiscal prudence. Our 2014 Budget reinforces our commitment to balancing the budget by 2017-18; it is essential that every area adheres to the program-spending objectives established in it. We will choose to invest wisely in initiatives that strengthen Ontario's competitive advantage, create jobs and provide vital public services to our families. The President of the Treasury Board, collaborating with the Minister of Finance, will work closely with you and your fellow Cabinet members to ensure that our government meets its fiscal targets. The President of the Treasury Board will also lead the government's efforts on accountability, openness and modernization as we implement new accountability measures across government.

As Minister of Energy, you will lead efforts to deliver on what continues to be our government's top energy priority — providing Ontarians with a clean, reliable and affordable supply of electricity.

This includes bringing on new, clean generation and ensuring investment in the transmission system to maintain grid reliability and serve new demand. It remains vitally important to manage the electricity supply mix prudently. Through integrated regional planning, you will identify solutions to meet regional needs, based on consultations that consider unique local requirements, circumstances and community priorities.

Your ministry's specific priorities include:

Implementing the Long-Term Energy Plan

- Continuing to implement the 2013 Long-Term Energy Plan (LTEP) which lays out our government's long-term vision for Ontario's energy system. Some of the key components of the LTEP are outlined below.

Pursuing Energy Conservation

- Ensuring that energy conservation continues to be one of our key goals as we implement the LTEP. This means helping ease the burden of rising energy costs on Ontario's ratepayers by pursuing conservation — wherever cost-effective — to meet energy needs when and where we need it.
- Implementing a Conservation First approach to energy planning, approval and procurement processes. You will do so by continuing to work with your ministry's agencies and with other ministers, including the President of the Treasury Board, the Minister of Economic Development, Employment and Infrastructure, and the Minister of Municipal Affairs and Housing.
- Ensuring that the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO) prioritize the implementation of Ontario's Conservation First approach to invest in conservation first, before new generation, where cost-effective.
- Working with the Ontario Energy Board to incorporate the Conservation First policy into local distributor planning processes for electricity and natural gas utilities — and the natural gas demand-side management framework under development.

Mitigating Electricity Prices for Residential Customers

- Continuing to help Ontarians by addressing the challenges they face from increasing electricity costs. You will continue to look for savings and efficiencies that will help keep electricity costs affordable for residential consumers.

- Developing and implementing a new residential electricity assistance program to help make electricity more affordable, particularly for low-income families, who spend a proportionately higher percentage of their income on energy and electricity.

- Working with the Ministry of Finance to deliver on our commitment to remove the Debt Retirement Charge from residential electricity bills after December 31, 2015. Residential ratepayers will benefit significantly from this change, and it is important that you ensure its effective implementation.

Mitigating Electricity Prices for Businesses

- Continuing to implement initiatives that support Ontario's businesses by helping them address rising energy costs. I ask that you lead our efforts to meet our commitment in the LTEP to ensure that where possible and appropriate — industrial electricity rate mitigation programs help support a dynamic and innovative climate for business to thrive, grow and create jobs.

- Helping to reduce energy costs for small business owners by implementing a five-point business energy savings plan, including on-bill financing and the expansion of saveONenergy for Business programs.

- Working with the Ontario Power Authority to implement a new stream of the Industrial Electricity Incentive program. This will provide electricity cost relief to companies that are able to establish or expand operations in Ontario.

- Proceeding with expansion of the Industrial Conservation Initiative. This will allow more businesses to benefit from lower electricity rates by shifting energy use away from peak periods — which, in turn, will benefit all electricity consumers by decreasing the need for costly peak generation.

Championing Renewable Energy

- Continuing to lead our government's commitment to renewable energy, with the aim of having 20,000 megawatts of renewable energy online by 2025. You will continue to monitor progress toward targets for wind, solar, bioenergy and hydroelectricity as part of Ontario energy reporting.

- Continuing to work with the ministry's agencies to implement a new competitive procurement process for renewable energy projects larger than 500 kilowatts that will take into account local needs and considerations.

- Continuing to respect the contracts that have been signed with energy producers, while always ensuring that these contracts enable the delivery of sustainable, affordable energy to Ontario's ratepayers.

- Working with the ministry's agencies and with municipal partners to ensure that municipalities participate meaningfully and effectively in the decision-making process for the placement of renewable energy projects, including wind and natural gas.

...14

- Ensuring that timelines for meeting the LTEP's energy storage procurement targets are met and that they address the regulatory barriers that limit the ability of energy storage technologies to compete in Ontario's electricity market. As well, you will explore opportunities to build on the pilot projects through additional procurement.

Refurbishing Nuclear Power Plants

- Working with Ontario Power Generation and Bruce Power to ensure that the crucial refurbishment of 10 nuclear units at the Darlington and Bruce generating stations over the next 16 years is completed efficiently and effectively.

Implementing and Doing Research and Development for a Smart Grid

- Working with the Minister of Research and Innovation and with the Minister of Economic Development, Employment and Infrastructure to continue with implementation of smart meters, smart grid technologies and advancements in customer service and choice.

Driving Efficiencies and Maximizing Return on Investment from Electricity Sector Agencies

- Working with the Minister of Finance and the President of the Treasury Board to consider recommendations from the Advisory Council on Government Assets on how to maximize the potential of Hydro One and Ontario Power Generation. Your goal is to ensure that Ontarians receive the value they deserve from these government enterprises.
- Working with the OPA and the IESO to implement legislation merging the two agencies into a single entity. Your goal is a smooth transition that achieves savings and efficiencies for energy ratepayers.
- Continuing to work with local distribution companies to ensure that they operate as efficiently as possible and produce savings that will benefit Ontario's ratepayers. They will do so through options such as voluntary consolidations and innovative partnerships.

Supporting Community-Level Energy Planning

- Encouraging municipalities and Aboriginal communities to develop their own community-level energy plans — and identify conservation opportunities and infrastructure priorities — as part of our commitment in the LTEP. You will support these efforts through the Municipal Energy Plan Program and the Aboriginal Community Energy Plans Program.

Consulting with Aboriginal Communities

- Working with other ministries and agencies to ensure that First Nation and Metis communities are consulted on any energy activity that could adversely affect their Aboriginal or treaty rights. Our government has recognized that Aboriginal participation in the energy sector is one of the keys to the economic development of First Nation and Malls communities.
- Continuing to support and encourage participation by First Nation and Mais communities in new generation and transmission projects — and in conservation initiatives. You will do so through programs such as the Aboriginal Energy Partnerships Program.

- Connecting remote communities is a priority for Ontario. Success in connecting remote communities will depend on contributions from all of the parties that will benefit from it, which includes the federal government. The province looks forward to a fair cost-sharing agreement with its federal counterparts to make sure this project becomes a reality for First Nation communities.
- You will also work with the Minister of Aboriginal Affairs, the federal government, and other agencies and ministries as needed to ensure communities are positioned to benefit from grid connection or a reduction in their dependence on diesel. This will support stronger, healthier northern remote communities by reducing barriers to growth, increasing economic development opportunities, ensuring access to clean energy, and improving social and living conditions for residents. For those communities where connection to the provincial grid is not viable, you will promote local options, such as renewable energy generation, to help reduce reliance on diesel fuel.

Exporting Ontario's Energy Expertise

- Working with the Minister of Citizenship, Immigration and International Trade and with the Minister of Economic Development, Employment and Infrastructure to develop and support ways to promote Ontario's energy expertise abroad. This will include nuclear refurbishments, the elimination of dirty coal generation, smart grid implementation and technical expertise in transmission and distribution.

Helping Develop a Canadian Energy Strategy

- Collaborating, including across borders, on the development of a strategy to ensure a clean, reliable and sustainable energy supply. You will work with other ministers, including the Minister of the Environment and Climate Change, of Intergovernmental Affairs, and of Economic Development, Employment and Infrastructure on the development of a Canadian Energy Strategy with other provinces and territories. The strategy should balance national interests with the unique profiles, priorities and needs of individual provinces and territories.
- Ensuring that the strategy includes co-ordinated efforts to improve energy efficiency and conservation, reduce greenhouse gas emissions, foster innovation in the energy sector and facilitate the safe transportation and transmission of energy. You will work with the Minister of the Environment and Climate Change to encourage federal partnership in addressing the climate change challenge — which is both local and global in scale.
- Ensuring that the strategy facilitates electricity imports and exports between Ontario and its neighbouring provinces by identifying barriers, solutions and opportunities for the development of interconnected transmission infrastructure.

Helping Ontarians Share in Affordable Supplies of Natural Gas

- Supporting programs led by the Minister of Economic Development, Employment and Infrastructure to help ensure that Ontario residents and industries are able to share in affordable supplies of natural gas. These programs, outlined below, will give consumers in underserved communities more energy choices, make commercial transportation more affordable, attract new industry to Ontario and benefit our agricultural producers.

- Helping the Minister of Economic Development, Employment and Infrastructure establish and implement a new Natural Gas Access Loan. Our government will provide up to $200 million over two years through this program to help communities partner with utilities to extend access to natural gas supplies.

- Helping the Minister of Economic Development, Employment and Infrastructure establish and implement a $30 million Natural Gas Economic Development Grant to accelerate projects with clear economic development potential.

Protecting Ontario's Interests in Pipeline Development

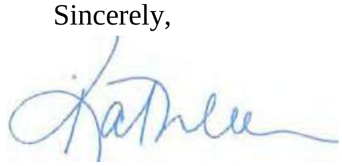
- Continuing to intervene in regulatory hearings about major pipeline proposals that directly affect Ontario. You will ensure that these interventions are consistent with Ontario's six pipeline principles, as outlined in the LTEP.

We have an ambitious agenda for the next four years. I know that, by working together in partnership, we can be successful. The above list of priority initiatives is not meant to be exhaustive, as there are many other responsibilities that you and your ministry will need to carry out. To that end, this mandate letter is to be used by your ministry to develop more detailed plans for implementation of the initiatives above, in addition to other initiatives not highlighted in this letter.

I ask that you continue to build on the strong relationships we have with the Ontario Public Service, the broader public sector, other levels of government, and the private, non-profit and voluntary sectors. We want to be the most open and transparent government in the country. We want to be a government that works for the people of this province — and with them. It is of the utmost importance that we lead responsibly, act with integrity, manage spending wisely and are accountable for every action we take.

I look forward to working together with you in building opportunity today, and securing the future for all Ontarians.

Sincerely,



Kathleen Wynne Premier

Appendix F – Ontario Premier's 2014 Mandate Letter to the Minister of Economic Development, Employment & Infrastructure

The Premier of Ontario	La première ministre de l'Ontario
Legislative Building Queen's Park Toronto, Ontario	Édifies de l'Assemblee législative Queen'sPark Toronto

Ontario

September 25, 2014

The Honourable Brad Duguid
Minister of Economic Development, Employment and Infrastructure
Eighth Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister Duguid:

I am honoured to welcome you to your role as Minister of Economic Development, Employment and Infrastructure. We have a strong Cabinet in place, and I am confident that together we will build Ontario up, create new opportunities and champion a secure future for people across our province. The people of Ontario have entrusted their government to be a force for good, and we will reward that trust by working every day in the best interests of every person in this province.

As we implement a balanced and comprehensive plan for Ontario, we will lead from the activist centre. We will place emphasis on partnerships with businesses, communities and people to help foster continued economic growth and make a positive impact on the lives of every Ontarian. This collaborative approach will shape all the work we do. It will ensure we engage people on the issues that matter the most to them, and that we implement meaningful solutions to our shared challenges.

Our government's most recent Speech from the Throne outlined a number of key priorities that will guide your work as minister. Growing the economy and helping to create good jobs are fundamental to building more opportunity and security, now and in the future. That critical priority is supported by strategic investments in the talent and skills of our people, from childhood to retirement. It is supported through the building of modem infrastructure, transit and a seamless transportation network. It is supported by a dynamic business climate that thrives on innovation, creativity and partnerships to foster greater prosperity. And it is reflected across all of our government, in every area, and will extensively inform our programs and policies.

As we move forward with our plan to grow the economy and create jobs, we will do so through the lens of fiscal prudence. Our 2014 Budget reinforces our commitment to balancing the budget by 2017-18; it is essential that every area adhere to the program-spending objectives established in it. We will choose to invest wisely in initiatives that strengthen Ontario's competitive advantage, create jobs and provide vital public services to our families. The President of the Treasury Board, collaborating with the Minister of Finance, will work closely with you and your fellow Cabinet members to ensure that our government meets its fiscal targets. The President of the Treasury Board will also lead the government's efforts on accountability, openness and modernization as we implement new accountability measures across government.

As Minister of Economic Development, Employment and Infrastructure, you will help to build a strong, diversified and globally competitive economy that will provide jobs, increase productivity and result in more prosperity for all Ontarians. You will ensure that our economic recovery is being felt in all areas of the province, and by all our people — including our youth. You will support a dynamic business climate — supported and enhanced by an innovative health care sector and a dynamic education system — that will help the province continue to attract new businesses to Ontario and compete globally for jobs and investment. You will co-ordinate the province's investments in world-class infrastructure — fostering economic growth and prosperity throughout the province.

Your ministry's specific priorities include:

Supporting a Dynamic Business Climate on a Foundation of Fiscal Responsibility

- Promoting Ontario's existing strengths and enhancing its reputation as a destination of choice for foreign and domestic private sector investments. You will create partnerships with business through new initiatives, such as the 10-year, $2.5-billion Jobs and Prosperity Fund — and continue existing initiatives, such as the Eastern and Southwestern Ontario Development funds, and — working with the Minister of Northern Development and Mines — the Northern Ontario Heritage Fund.

- Collaborating with the Minister of Finance, the President of the Treasury Board and partner ministers to develop a framework to identify and evaluate optimal partnership investments. Your goal is to strengthen the province's approach to business supports while balancing the government's commitment to fiscal sustainability.

- Developing strategies for key-growth sectors, such as advanced manufacturing and automotive, agri-food, cleantech, financial services, information and communications technology, natural resources, tourism, media and culture. Together, these strategies will represent the government's broader economic policy objectives and will support investment and job creation. I ask that you work in co-operation with partner ministers, industry, postsecondary institutions and the not-for-profit sector to develop these strategies.

- Leading work, as the minister responsible for trade policy — in co-operation with the federal government and Canada's provinces and territories — to find ways of reducing trade barriers and increasing exports nationally and internationally.

- Partnering with the Minister of Citizenship, Immigration and International Trade to increase Ontario exports and promote Ontario-made goods and services.

- Working with the Minister of Citizenship, Immigration and International Trade to establish a ministerial working group. You and the minister will co-chair the group, which will include the ministers of: Agriculture, Food and Rural Affairs; Education; Energy; Health and Long-Term Care; Northern

Development and Mines; Research and Innovation/Training, Colleges and Universities; Tourism, Culture and Sport and other ministers, as appropriate. The committee's objective is to ensure strong collaboration and information-sharing — and maximize international trade and foreign investment opportunities.

- Expanding the reach of Ontario's exports — particularly to fast-growing emerging markets — in partnership with the Minister of Citizenship, Immigration and International Trade. You will jointly pursue initiatives that expand the opportunity for Ontario firms to connect with foreign buyers and investors, showcase innovative goods and services, and find new markets.

- Providing support to communities that are still recovering from the global recession, with particular focus on Southwestern and Northern Ontario. You will work with partner ministers to develop strategies to attract new investment and jobs — and connect the demand for jobs with our highly trained workforce in these areas.

- Working in partnership with business and entrepreneurs to build on our existing commitment to create a strong social enterprise market in Ontario.

- Continuing to work with partner ministers and industry to explore initiatives to reduce regulatory and administrative burdens, as proposed in the Better Business Climate Act, 2014. If the legislation is passed, I ask that you begin to work with key partners to develop regional cluster plans. Your goal is to adopt smarter regulatory practices without putting public safety at risk.

- Continuing to implement the Ontario Youth Jobs Strategy, in partnership with the Minister of Training, Colleges and Universities. The strategy aims to address the youth unemployment rate by investing $295 million in measures to connect young people with promising careers — and increase opportunities for youth across the province.

- Increasing the number of employment opportunities for Ontarians of all abilities by establishing new partnerships with business and persons with disabilities.

- Working with partners to build an accessible Ontario by 2025. I ask that you explore options to develop new accessibility standards in the education or health sector.

Building Modern Infrastructure

- Working with your colleagues in the legislature to seek the passage of Bill 6, the Infrastructure for Jobs and Prosperity Act, which would establish the requirements for long-term infrastructure planning.

- Leading the development of the province's long-term infrastructure plan. You will collaborate with partner ministers to identify the government's strategic priorities for infrastructure investment.

- Prioritizing the government's infrastructure investments — in partnership with the President of the Treasury Board to ensure alignment with Ontario's economic development priorities.

- Continuing to support strong communities across Ontario by launching the new permanent Ontario Community Infrastructure Fund. The initiative will provide $100 million per year for investment in roads, highways and water infrastructure projects in Ontario’s small and mid-sized communities.

Developing Infrastructure Investment Strategies

- Seeking opportunities to further refine our capital investment strategies for infrastructure. Your goal is to align these strategies with asset management planning, growth planning, our economic goals, environmental priorities and the needs of Ontarians.

- Embracing opportunities to encourage the adoption of innovative technologies that support economic growth and long-term savings. I ask that you ensure that public infrastructure investments encourage the adoption of approaches that maximize the value of our infrastructure dollars and minimize the long-term cost of maintaining infrastructure assets — including ensuring resiliency to the impact of climate change.

- Implementing the proposed Infrastructure for Jobs and Prosperity Act, 2014, if passed. The act would enshrine evidence-based, long-term infrastructure planning in Ontario and support opportunities for apprenticeships, at-risk youth and local communities.

Maintaining Models of Alternative Financing and Procurement

- Continuing to refine the approach to delivering Ontario’s highly effective Alternative Financing and Procurement (AFP) model — learning from the experience of past projects and current best practices. Your goal is to ensure that AFP remains the best system possible to deliver transit and other infrastructure projects on time, on budget and to specification.

Extending Access to Natural Gas

- Fulfilling our government's commitment to create a new Natural Gas Access Loan — which will provide up to $200 million over two years to help communities partner with utilities to extend access to natural gas supplies. I also ask that you establish a $30- million Natural Gas Economic Development Grant to accelerate projects with clear economic development potential. Your goal is to provide consumers in underserved communities more energy choices, make commercial transportation more affordable, attract new industry to Ontario, and benefit our agricultural producers.

We have an ambitious agenda for the next four years. I know that, by working together in partnership, we can be successful. The above list of priority initiatives is not meant to be exhaustive, as there are many other responsibilities that you and your ministry will need to carry out. To that end, this mandate letter is to be used by your ministry to develop more detailed plans for implementation of the initiatives above, in addition to other initiatives not highlighted in this letter.

I ask that you continue to build on the strong relationships we have with the Ontario Public Service, the broader public sector, other levels of government, and the private, non-profit and voluntary sectors. We want to be the most open and transparent government in the country. We want to be a government that works for the people of this province — and with them. It is of the utmost importance that we lead responsibly, act with integrity, manage spending wisely and are accountable for every action we take.

I look forward to working together with you in building opportunity today, and securing the future for all Ontarians.

Sincerely.

Kathleen Wynne Premier

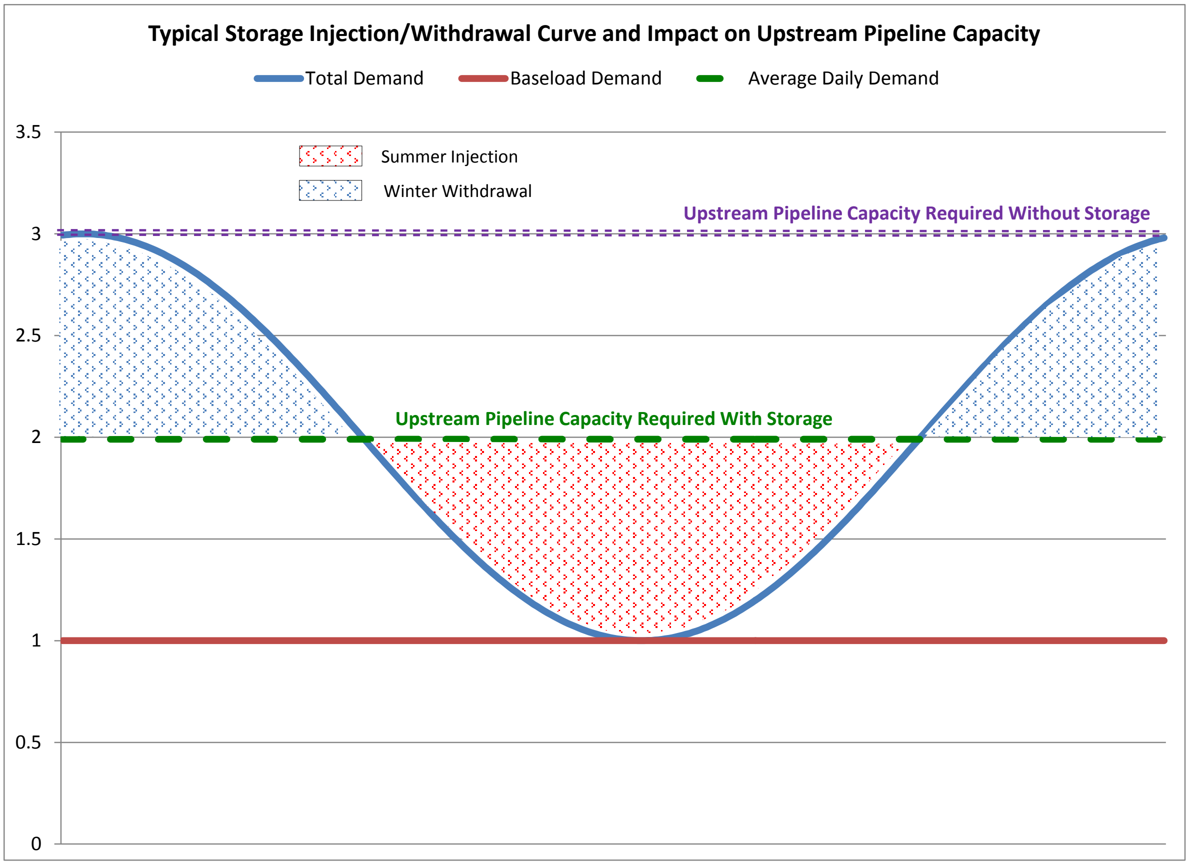
Appendix G – Natural Gas Storage

Background

Underground natural gas storage can perform a valuable function in the operation of a natural gas distribution business. Storage can generally reduce the capital cost of the pipeline systems feeding heat sensitive customers as well as provide an opportunity to purchase gas supplies during off-peak periods when gas prices are lower, for subsequent use during peak times

Natural gas distribution loads usually have a large heat sensitive component of their total load. The distribution system therefore must be designed and built to accommodate the peak hourly demand from these heat sensitive loads (along with other non-heat sensitive loads) based on the coldest expected design conditions. Natural gas storage provides an opportunity to reduce the size of the pipeline systems situated upstream of storage, and hence the capital cost, as they can be designed to the average flow rate throughout the year by injecting surplus into storage during off-peak summer conditions for subsequent withdrawal during on-peak times. Pipeline systems downstream of storage must however continue to be designed to accommodate the peak hourly conditions. Therefore the closer the storage is situated to the heat sensitive market, the more efficient the design of the upstream pipeline system. This efficiency is illustrated in the chart below. Storage situated close to the market can also facilitate some further day-to-day balancing.

It is understood that NORTHERN has one or more nearly depleted production reservoirs in the region that may be able to be converted to storage to serve the distribution load in the area. The lower resulting capital costs of the upstream infrastructure may result in a lower overall cost to serve the South Bruce region over other proposals that may not have storage in the region.



The shifting of gas purchases to off-peak periods is a natural physical hedge on gas costs employed by many distribution companies, and while beneficial, this ability to physically hedge the supply costs is not unique to the NORTHERN proposal.

Approvals

Underground storage is a provincially regulated resource in Ontario, in order to develop underground storage, there are a number of requisite approvals which are additional to the potential approvals or commercial agreements that may be required from the affected landowners and municipalities. More specifically, the provincial approvals include:

- The Minister of Natural Resources has authority to approve the development of natural gas wells pursuant to the Ontario Gas and Salt Resources Act R.S.O. 1990, CHAPTER P.12 including ONTARIO REGULATION 245/97
- The storage developer is required to obtain various storage related approvals from the Ontario Energy Board (OEB) including:
    - An Order designating a gas storage area pursuant to section 36.1(1) of the Ontario Energy Board Act; 1998. S.O. 1998, c.15, Schedule B ("OEB Act");
    - Authority to inject gas into, store gas in, and remove gas from the storage pool, pursuant to subsection 38(1) of the OEB Act;

- All wells to be drilled in a designated storage area must be referred by the Minister of Natural Resources to the OEB under subsection 40(1) of the OEB Act and the Board is required to provide a favourable report to the Minister in order for the Minister to approve such wells.

In most of southwestern Ontario, the landowner owns the rights to minerals, including oil and gas, located beneath their property. Most underground storage facilities are converted natural gas production reservoirs; therefore the producer must first obtain from the landowner the necessary mineral leases to produce the natural gas. Should the reservoir have potential to be converted to a storage reservoir, the storage operators must also obtain the approval of landowners in the form of an Underground Natural Gas Storage Lease Agreement.

Storage Design

The technical design aspects of underground gas storage are governed by the CSA Z341 Storage of Hydrocarbons in Underground Formations code.

As noted, most underground natural gas storage facilities once were production reservoirs and the information gained about the underground formation through the production process is invaluable to assist with the suitability and the design of the storage facility.

Once the formation has been discovered, wells are drilled and associated equipment are installed to produce the natural gas. This production phase can occur over a number of years. If the formation is then found suitable for storage, the facility is then re-designed to accommodate this new requirement. As a production facility, the gas is usually withdrawn over many years. Once converted to storage service, the facilities must now be designed to have the gas injected back into the ground, normally over the summer months, for subsequent withdrawal over the winter months. These typically involve much higher rates of flow as gas is being injected and withdrawn over a few months rather than years, when the facility operated as a production facility. As a result additional wells are usually required as is the need for compression to raise the pressure of the gas being forced back into the reservoir.

A variety of technical studies are required to demonstrate the overall suitability of a reservoir to be used as storage in order to obtain the requisite regulatory approvals. These can include (but are not limited to) studies to:

- Define the areal extent of the reservoir
- Asses the overall technical suitability of the reservoir
- Examine the geological nature of the reservoir
- Simulate the flow of gas into and out of the reservoir
- Ensure the safe containment of the gas in the subsurface formation

Storage Operation

As part of the regulatory approval process, storage operators are required to have an operating plan that demonstrates that they have qualified personnel that are able to safely operate the proposed facility. This includes the development of an emergency response plan to deal with accidental hydrocarbon release, equipment failure, natural perils, and third-party emergencies.

Storage Rate Regulation

In addition to the technical aspects of storage regulation, historically the storage rates charged by utilities to all of its customers were also rate regulated. The OEB, in its EB-2005-0551 determined that the storage market in Ontario was competitive and that neither Enbridge nor Union (the major storage operators in Ontario) had market power[3] and therefore said:

> *The Board will cease regulating the prices charged for the following storage services:*
>
> - *all storage services offered by Union and Enbridge to customers outside their franchise areas;*
> - *new storage services offered by Union and Enbridge to their in-franchise customers; and,*
> - *all storage services offered by other storage operators, including storage operators affiliated with Union and Enbridge.*
>
> *Rates for storage services provided to Union's and Enbridge's distribution customers will continue to be regulat*ed by the Board on a cost-of-service basis.

Based on this decision, it is reasonable to conclude that in the event that NORTHERN develops storage and uses it to help balance its distribution loads, the storage rate itself would not be subject to rate regulation and the rate would be set based on market conditions. However, since NORTHERN would have distribution rates that would be subject to regulation, and the costs related to storage would be a non-arm's length transaction, it would have to demonstrate that the storage costs that it was including in the distribution rates was a prudently incurred cost.

Similarly if Union (or Enbridge) were to supply storage services to South Bruce, assuming they did not own the distribution franchise, they too would be able to charge a commercially negotiated rate. If however Union were to have the distribution franchise, and supplied storage services, it would only be allowed to charge the OEB approved rate for storage services.

NORTHERN Storage

NORTHERN made application on May 27, 2003 to the OEB for approval to develop the Ashfield production pool into underground storage. The Ashfield pool is situated Township of

[3] EB-2005-0051 Decision November 7, 2006 page 3

Ashfield-Colborne-West Wawanosh near Port Albert. This was filed under the hearing docket numbers RP-2003-0104 and EB-2003-0141/0142/0143

NORTHERN indicated that the converted pool would have a capacity of 2.78 BCF (78,673 10^3m^3 or 2.98 PJ). The development plan was to convert one of the existing two wells into an injection/withdrawal well, convert the other one to an observation well and install 1,600 hp of compression. These facilities were planned to be phased in over time. The proposed pressure in the reservoir would be raised over time from the discovery pressure of 434 psig to 1,184 psig. The fully operational pressure in the reservoir would have a similar pressure gradient as many other storage pools in Ontario.

The application to the OEB was adjourned sine die on January 30, 2004 on consent.[4]

NORTHERN will have to reapply to obtain the necessary development approvals if it wishes to use storage as part of its overall development plan. Some of the volumetric assumptions used by NORTHERN rely on re-pressuring the reservoir to a level about 2.7 times the discovery pressure. While this may ultimately be technically feasible, the OEB may require that the pressure be raised over several years with appropriate testing to ensure the integrity of the reservoir. This would reduce the effective volume of gas that could be stored. Since the 5th year total annual volume of projected gas sales, in the region, has been estimated to be 30-45 10^6m^3 (1.1-1.6 bcf)[5] this potential limitation is not seen as significant.

It is not clear to what extent the NORTHERN pipeline design relies on embedded storage to optimize upstream pipe sizes and cost. To the extent that the upstream pipe sizes are reduced to benefit from the embedded storage, it would be advisable to ensure the necessary regulatory approvals have been obtained and other storage related development risks are minimized prior to the upstream pipe sizes being finalized.

As previously noted, NORTHERN would be exempt from rate regulation if it were to provide storage services to the region. It would therefore be appropriate to understand in advance the proposed commercial terms for storage services.

NORTHERN also continues to operate production facilities in the region. To the extent that these production volumes are transported out of the region, there ought to be some form of regulated rate to allow these volumes access to the distribution system. If the production volumes are totally used within the distribution business, then the transfer price of the gas supply will also need to be negotiated. Assurances will also need to be provided by NORTHERN that the quality of the productions volumes meets normal distribution quality specifications.

[4] Procedural order No. 4
[5] Report Exhibit 19

TOR01: 5723023: v1