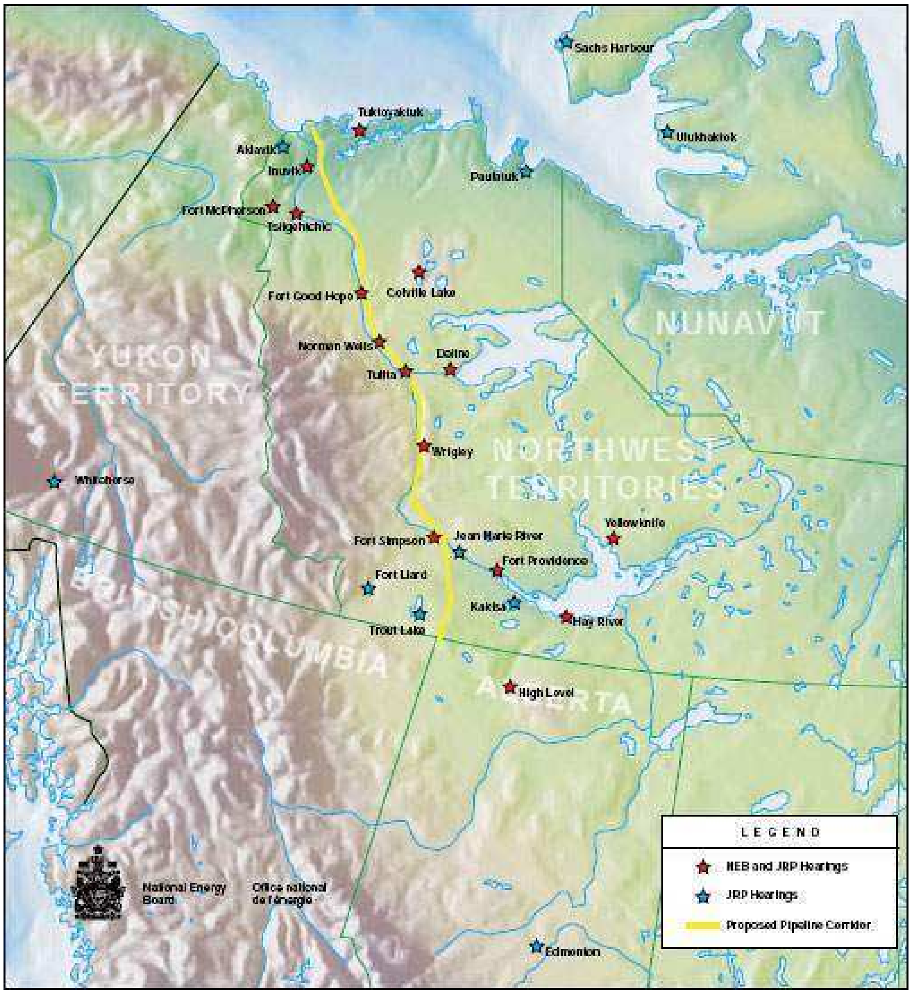
Mackenzie Valley – Community Gas Conversion

Preliminary Feasibility Study – Final Report



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Industry, Tourism and Investment

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Content

APPENDICES

1.0 Executive Summary

On December 16, 2010, the National Energy Board (NEB) released its Reasons for Decision regarding the Mackenzie Gas Project (MGP). As part of the conditions associated with the Certificate for Public Convenience and Necessity for the MGP, the Proponents of the MPG (the "MGP Proponents") were directed to provide for construction of metering and depressurization facilities along lateral pipelines for the communities, provided that certain economic conditions are met. In accordance with this provision, the Government of the Northwest Territory (GNWT) commissioned Canadian Gas Services International (CGSI) to complete a Preliminary Feasibility Study to determine the economic viability of converting the heating and electrical generation load requirements from diesel to natural gas for 13 communities in the Northwest Territories, assuming that the cost of the Custody Transfer Stations (CTS) and the Community Gate Stations (CGS) are excluded from the analyses. Three of these communities (Fort Good Hope, Tulita and Fort Simpson) were the subject of previous CGSI studies, which have been updated, while the remaining ten communities had not been subject to previous economic viability studies by CGSI.

Based on the results of the Preliminary Analyses, the communities have been categorized into five groups:

Group 1: Communities for which conversion to natural gas is economically feasible without the CPCN provisions, and for which the exclusion of costs associated with the CTS and CGS further improves the economic feasibility of the conversion:

- Fort Good Hope
- Tulita
- Fort Simpson

Group 2: Communities that have already been converted to natural gas, and that could benefit from lower commodity costs and increased security of supply, by sourcing gas from the MGP:

- Norman Wells
- Inuvik

Group 3: Communities for which conversion to natural gas is economically feasible if the costs of the CTS and CGS are excluded from the analysis:

- Wrigley

Group 4: Communities for which conversion to natural gas could be economically feasible, but only if capital exclusions exceeded the current parameters defined by the NEB:

- Tuktoyaktuk
- Fort McPherson
- Aklavik
- Deline

Group 5: Communities for which conversion to natural gas will not be economically feasible, even with changes to the current parameters defined by the NEB:

- Tsiigehtchic
- Jean Marie River
- Colville Lake

These Preliminary Analyses have been undertaken by comparing the present value of cost savings associated with the conversion to natural gas (primarily commodity cost savings), to the present value of the incremental capital and operating costs required for this conversion. For communities classified in Groups 1 and 3, the combination of population size and distance from the MGP suggest that conversion to natural gas may be economically feasible. For communities classified in Group 4, conversion could theoretically be economically feasible, but only if the provisions of the CPCN were expanded to include a portion of the cost of the lateral. For communities classified in Group 5, the populations are too small to justify the expenditure required to construct a lateral to carry gas from the MGP to the communities, even with the cost of the lateral excluded. Under the existing parameters, if conversion to gas for communities in Groups 4 and 5 is desired, alternative options should be examined, including sourcing gas from local wells, and/or transporting compressed natural gas (CNG) or liquefied natural gas (LNG) from the MGP by truck. This could be considered for other new communities as well.

For communities classified in Group 2, there are no commodity cost savings with which to offset the capital costs associated with sourcing gas from the MGP. Therefore, the analyses are limited to a summary of the estimated capital costs associated with converting the source of supply. A separate study will be required to estimate the level of commodity cost savings that may be available for these communities, and to analyze the qualitative benefits (including security of supply) associated with such a conversion.

Specific estimated cost and gas demand data for each community is summarized in Tables 1-1 and 1-2 on the following page.

Table 1-1
Benefit Summary – Over 20 Years

Community	Lateral Distance (km)	Projected Annual Demand (GJ)	NPV of Status Quo Costs ($ mm)	NPV of Costs on Gas (including CTS and CGS) ($ mm)	NPV of Costs on Gas (excluding CTS and CGS) ($ mm)	GHG Reduction ('000 tonnes of CO_2)
Fort Good Hope	5	54,314	$18.5	$11.7	$10.3	33
Tulita	7	52,254	$17.1	$11.7	$10.3	31
Fort Simpson	20	129,274	$40.4	$35.8	$34.4	66
Inuvik	28	502,025	n/a	n/a	n/a	n/a
Norman Wells	1	58,931*	n/a	n/a	n/a	n/a
Tuktoyaktuk	150	66,337	$28.2	$52.5	$51.1	38
Wrigley	5	11,819	$5.2	$6.4	$5.0	7
Fort McPherson	140	68,722	$26.5	$48.2	$46.8	40
Aklavik	90	35,174	$15.2	$25.3	$23.9	17
Deline	110	52,118	$18.4	$37.6	$36.2	30
Tsiigehtchic	120	15,116	$7.0	$24.5	n/a	10
Jean Marie River	25	4,516	$2.0	$6.9	n/a	3
Colville Lake	170	9,053	$3.6	$30.7	n/a	5

** Includes only heating and hot water.*

Table 1-2
Summary of Capital Cost and Annual O&M Cost

Community	Capital Costs ($ '000)						Avg. Annual O&M Cost ($ '000)		
	Lateral	CTS	Community Gate Station	Distr. Mains	Customer Services	Gen Set Convert	Lateral	CTS	Distr. & Other
Fort Good Hope	$1,330	$1,302	$729	$1,059	$1,512	$3,930	$30	$31	$615
Tulita	$1,862	$1,302	$729	$981	$1,405	$3,750	$40	$31	$631
Fort Simpson	$10,320	$1,302	$729	$2,980	$3,950	$11,173	$195	$31	$1,644
Inuvik	$14,448	$1,302	$729	n/a	n/a	n/a	$270	$31	$31*
Norman Wells	$266	$1,302	$729	n/a	n/a	n/a	$11	$31	$31*
Tuktoyaktuk	$58,950	$1,302	$729	$1,697	$2,373	$7,497	$1,087	$31	$1,694
Wrigley	$1,330	$1,302	$729	$364	$528	$2,655	$30	$31	$333
Fort McPherson	$55,020	$1,302	$729	$1,440	$2,023	$6,205	$1,015	$31	$1,497
Aklavik	$23,940	$1,302	$729	$1,337	$1,904	$4,352	$446	$31	$1,015
Deline	$43,230	$1,302	$729	$1,105	$1,573	$3,786	$799	$31	$1,141
Tsiigehtchic	$31,920	$1,302	$729	$410	$584	$1,700	$593	$31	$669
Jean Marie River	$6,650	$1,302	$729	$166	$235	$782	$128	$31	$233
Colville Lake	$45,220	$1,302	$729	$203	$302	$816	$838	$31	$697

** Includes only an allowance for the incremental Community Gate Station*

2.0 Introduction & Project Overview

2.1. Project Overview

On December 16, 2010, the National Energy Board (NEB) released reasons for the decision regarding the Mackenzie Gas Project (MGP). As part of the conditions associated with the Certificate for Public Convenience and Necessity for the MGP, the Proponents of the MPG (the "MGP Proponents") were directed to provide for construction of metering and depressurization facilities along lateral pipelines for up to 8 communities, provided that certain economic conditions are met. In accordance with this provision, the Government of the Northwest Territory (GNWT) commissioned Canadian Gas Services International (CGSI) to complete a Preliminary Feasibility Study to determine the economic viability of converting the heating and electrical generation load requirements from diesel to natural gas for 13 communities in the Northwest Territories, assuming that the cost of the Custody Transfer Stations (CTS) and the Community Gate Stations (CGS) are excluded from the analyses. Three of these communities (Fort Good Hope, Tulita and Fort Simpson) were the subject of previous CGSI studies, which have been updated, while the remaining ten communities had not been subject to previous economic viability studies by CGSI.

In aggregate, the 13 communities comprise:

- Fort Good Hope
- Tulita
- Fort Simpson
- Norman Wells
- Inuvik
- Deline
- Wrigley
- Jean Marie River
- Tsiigehtchic
- Fort McPherson
- Aklavik
- Tuktoyaktuk
- Colville Lake

2.2. Scope & Terms of Reference

For purposes of this study, the 13 communities have been divided into two groups:

1. Updated Study Group
    - Comprises the communities of Fort Good Hope, Tulita, and Fort Simpson
2. New Study Group
    - Comprises the remaining 10 communities

The Updated Study Group represents the three communities for which previous studies have been performed. These studies include:

- 2008 Encor Gas Conversion Feasibility Study for Fort Good Hope, Tulita and Fort Simpson
- 2010 CGSI Report on Fort Simpson Power Plant Replacement/Conversion
- 2011 Associated Report on Fort Good Hope Diesel Plant Replacement
- 2011 Associated Report on Tulita Diesel Plant Replacement

Within the context of these studies, detailed investigations were undertaken with respect to many of the input variables, including cost and condition of existing generating equipment, the specifications and cost for replacement equipment, and operation & maintenance (O&M) costs for existing and potential replacement systems.

The terms of reference for this study did not include gathering an equivalent degree of information on the 10 communities that form the New Study Group. Rather, this study utilizes readily available information regarding demographics, generating capacity, and energy use within these communities, and combines this information with reasonable assumptions inferred from the previous research conducted for the Updated Study Group. The result is a Preliminary Economic Feasibility Assessment that provides an indication of the likelihood that each of these communities will pass the economic test defined by the NEB, but one that must be supported by a more detailed Feasibility Study before any definitive answers can be determined.

2.3. Methodology

This study estimates the future costs required to satisfy the heating and electrical generation load requirements for each of the communities under both “status quo” and “conversion to natural gas” scenarios through 2038. These future costs are then discounted to determine the Net Present Value (NPV) of each scenario. Given that the financial model is focussed on the projection of cash outflows (costs), the scenario with the lowest NPV represents the lowest cost alternative for the customer.

The study incorporates two sensitivities for each community, including:

1. The “base case” in which all costs associated with the conversion to natural gas sourced from the MGP are included in the analysis.
2. A “CPCN case” in which the costs of the CTS and CGS are excluded from the analysis.

Given that the conversion to natural gas will also provide significant environmental benefits, the analysis also projects the overall reductions to Greenhouse Gas emissions (GHG).

3.0 Global Assumptions

The financial analysis undertaken in accordance with this Study is based on a variety of assumptions and projections. Although some of these assumptions are specific to each individual community, many are global assumptions that impact all 13 communities included in the Study. Some of the more influential global assumptions are discussed in greater detail below:

3.1. Fuel Price Forecast

The results of the financial analysis are highly dependent on the forecast price for both diesel and natural gas. Prior analyses undertaken for the Updated Study Group have relied on forecasts provided by GLJ Petroleum Consultants Ltd. To ensure consistency, this Study utilizes the GLJ Price Forecast dated October 1, 2011. Specifically, the natural gas forecast is based on the projected AECO/NIT Spot Price, while the diesel forecast is based on the projected price at Edmonton for Light Sweet Crude Oil 40API, 0.3% Sulphur.

3.2. MVP in Service

This Study assumes that the Mackenzie Valley Pipeline (MVP) will be in service in November of 2019.

3.3. Demand Forecast

To determine demand forecasts through 2037 (the "Analysis Period"), the Study starts with current diesel consumption for heating and electrical load requirements, and adjusts those usage rates for estimated changes in population growth for each of the communities. Population growth projections through 2030 were provided by the NWT Bureau of Statistics, while growth beyond 2030 was assumed to occur at the same rate as the rate of growth from 2025 to 2030. The growth in both residential and commercial consumption is expected to mirror the growth of the population of each community as a whole.

3.4. Generation Efficiencies

Based on the analyses undertaken in accordance with the 2010 CGSI Report, the status quo generation efficiency is assumed to be 38.6%, while the efficiency of natural gas generation is assumed to be 38%.

3.5. Load Factors

Based on work undertaken in the context of the 2010 CGSI Report, and an analysis of industry best practices, average residential and non-residential status quo load factors are assumed to be 32% for each community.

3.6. *Capital Costs*

3.6.1. Pressure Reduction

The Study assumes that two pressure reduction stations (PRS) will be required for each community. The first, referred to as the Custody Transfer Station (CTS), reduces the pressure from high to medium, and would be placed at the point where the lateral connects to the MVP. The second, referred to as the Community Gate Station, reduces the pressure to distribution pressure, and would be placed where the lateral connects to the community distribution system. Based on the analyses undertaken for the Updated Study Group in 2008 and 2010, this Study assumes a cost of $1.3 million for the PRS located at the MVP connection, and a price of $730,000 for the PRS located at the community gate station. These budgets include the cost of all required valves, heaters and metres, including the required custody transfer meter at the CTS.

It should be noted that there may be opportunities to economize on the cost of pressure reduction stations by having a single PRS serve the laterals to multiple communities. For example, the laterals for Fort Good Hope and Colville Lake could be served by a single PRS, while the laterals for Tulita and Deline could also be served by a single PRS. However, undertaking the engineering analysis required to verify the feasibility of these options and determine their associated costs is not included within the scope of this Study. Therefore, this analysis makes the more conservative assumption of 2 PRS's for each community.

3.6.2. Laterals

The 2008 Encor study reflected lateral costs per diameter-inch per kilometre ranging from a low of $112,000 to a high of $127,000. After allowing for 5% inflation since 2008, this analysis assumes the following lateral costs:

- $133,000 per diameter-inch per km for 2" pipe
- $131,000 per diameter-inch per km for 3" pipe
- $129,000 per diameter-inch per km for 4" pipe

The sliding cost scale above reflects the fact that certain costs, such as mobilization and trenching, are identical regardless of the pipe diameter utilized.

It should be noted that these projections are significantly lower than those reflected in NEB submissions made by the MGP Proponents. However, based on the analysis undertaken in 2008, and actual costs incurred in constructing the lateral to Inuvik, CGSI is confident that these estimates are realistic. In fact, utilizing newly developed no-weld flex-pipe technology, it may be possible to further reduce these costs. However, determination of the cost and applicability of this new technology would require additional engineering analysis that extends beyond the scope of this study.

3.6.3. Services

In accordance with the 2008 Encor Study and the 2010 CGSI Report, an inflation adjusted budget of $1,400 per connection has been allocated for services, comprising the customer connection from the distribution system and the customer meter.

3.6.4. Generation Conversion Cost

Separate analyses were undertaken to determine the cost of converting the existing generation from diesel to natural gas for the three communities in the Updated Study Group. Based on studies undertaken by CGSI and Associated Engineering, the cost in Fort Simpson and Tulita was estimated at approximately $3,400 per kilowatt of generating capacity, while an Associated Engineering study estimated the cost in Fort Good Hope at approximately $3,200 per kilowatt of generating capacity. On this basis, the analysis performed for this Study assumes a generation conversion cost of $3,400 per kilowatt of generating capacity for the communities in the New Study Group.

3.7. Discount Rate

In financial theory, a discount rate is determined by the risks associated with the underlying cash flows. The riskier the cash flows, the higher the discount rate, since future cash flows are more uncertain and therefore should be valued lower in today's dollars. When valuing stocks or engaging in capital budgeting, there are specific quantifiable formulas that can be applied to determine a discount rate; thus limiting the degree of variance among the discount rates applied by financial professionals.

In the context of this Study, such quantifiable formulas do not exist. A strong case can be made that the various components of the cash flow should be discounted separately, in which case Capital and Operating Costs would be discounted at a lower rate, and commodity costs would be discounted at a higher rate, due to the higher degree of uncertainty associated with future commodity prices. However, for purposes of this Study, a discount rate of 10% has been utilized to maintain consistency with the Encor Study undertaken in 2008, and the CGSI Report completed in 2010.

A sensitivity analysis has been completed for the community of Fort Good Hope utilizing discount rates of 5% and 15%, in order to gauge the degree to which the results of the analysis are impacted by the selection of a discount rate. Although the discount rate certainly impacted the nominal value of the savings from a conversion to natural gas, the relative difference in the cost of the status quo versus the cost of a conversion to natural gas was not overly significant. Therefore, it was not deemed necessary to duplicate these sensitivities for the remaining communities, as the pattern would be identical given that commodity prices are a global assumption in the model.

3.8. MGP Tolls

Based on MGPs commitment to provided discounted tolls for gas delivered to communities in the Northwest Territories, this study applies a 50% discount to the MGP toll for gas delivered in Northwest Territories. This is consistent with the assumptions for MGP Tolls in the 2010 CGSI Report on Fort Simpson.

3.9. Incremental Toll Calculation

As noted in Section 2.1, where applicable CGSI has performed a second analysis in which the capital costs associated with the Custody Transfer Stations and Community Gate Stations have been excluded. In performing these analyses, it has been assumed that the cost of the Custody Transfer Stations and Community Gate Stations would be borne by a toll applicable to the entire volume of gas transported on the MGP. Given the significant volumes that are expected to be transported on the MGP, it is not likely that the addition of the capital costs outlined herein will have a material impact on the overall tolls for the pipeline. Therefore, no changes to the MGP tolls have been assumed for the various scenarios presented herein.

If the tolls applicable to any contribution from the MGP Proponents are levied only against the NWT communities, the source of capital will change, but the economic feasibility of the community conversions will not be impacted. In other words, if the NWT communities are forced to bear 100% of the cost of the Custody Transfer Stations and Community Gate Stations, whether the required capital investment is made by GNWT or by the MGP Proponents is irrelevant to the feasibility of the conversion to gas. Under this system, at best, GNWT could insist upon a “pooling” mechanism, whereby a portion of the economic benefits realized by the communities for which conversion to gas is economically feasible can be used to subsidize one or more communities for which conversion is not economically feasible; thus enabling these additional communities to be converted as well.

4.0 Fort Good Hope

4.1. Key Assumptions

4.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Fort Good Hope for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.12 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 2,861 litres of heating oil per year, while the average commercial building consumes 10,220 litres per year. By 2019, it is assumed that there will be 210 residential accounts and 55 commercial accounts in Fort Good Hope, decreasing to 192 and 51 by 2038. Under the Status Quo, it is assumed that 34.9 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 32.2 million litres.

4.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

4.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 5 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2” will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains was taken from the 2008 Encor Study. Specific capital costs are outlined in Table 1-2, and in Appendix B.

4.1.4. Cost to Convert Power Generation to Natural Gas

In accordance with the Associated Engineering Study completed in 2011, the capital cost for conversion from diesel generators to natural gas reciprocating generators is estimated at $3.93 million.

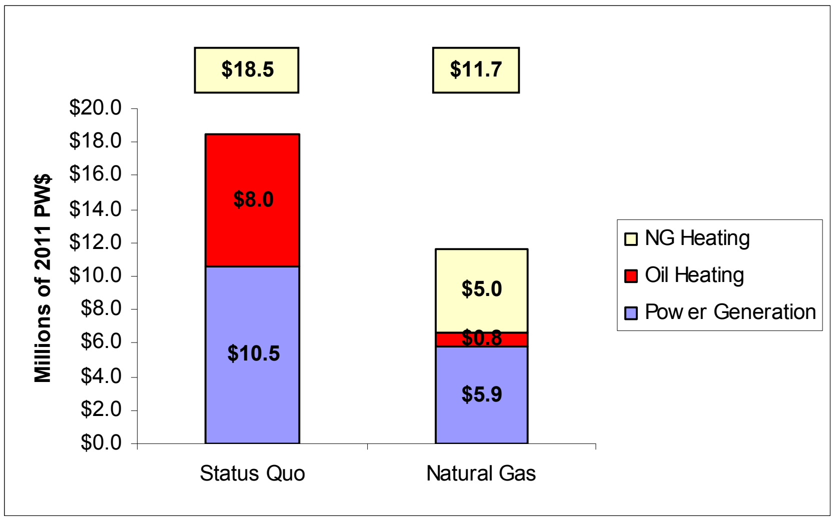
4.1.5. O&M Costs

Annual O&M cost are assumed to average approximately $676,000 in present value terms, of which approximately 91% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

4.2. Analysis Results

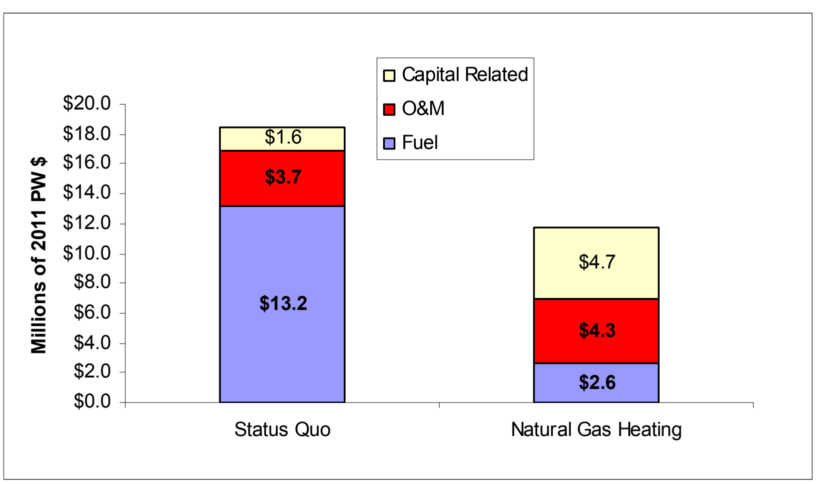
The updated analysis for Fort Good Hope continues to demonstrate a highly favourable return from a conversion to natural gas for heating and power generation, as illustrated in the graph below. This graph indicates that the present value of the Status Quo option is $18.5 million, a premium of $6.8 million or over 58% relative to the present value of the costs associated with a conversion to natural gas.

Figure 4-1
NPV Comparison of Status Quo and Conversion to Natural Gas



The vast majority of these overall savings can be attributed to savings in commodity costs over the Analysis Period. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $10.6 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 4-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs

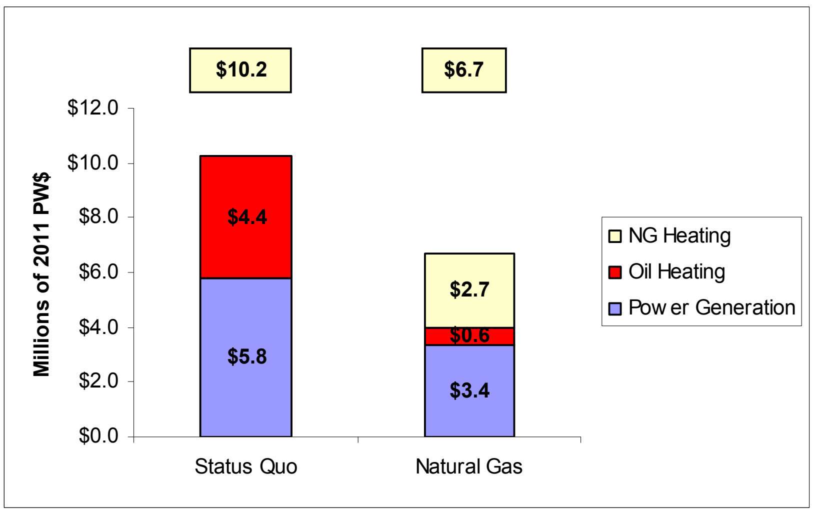


If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would also disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

4.3. Discount Rate Sensitivity

The impact of increasing the applicable discount rate to 15% is shown in the following graph:

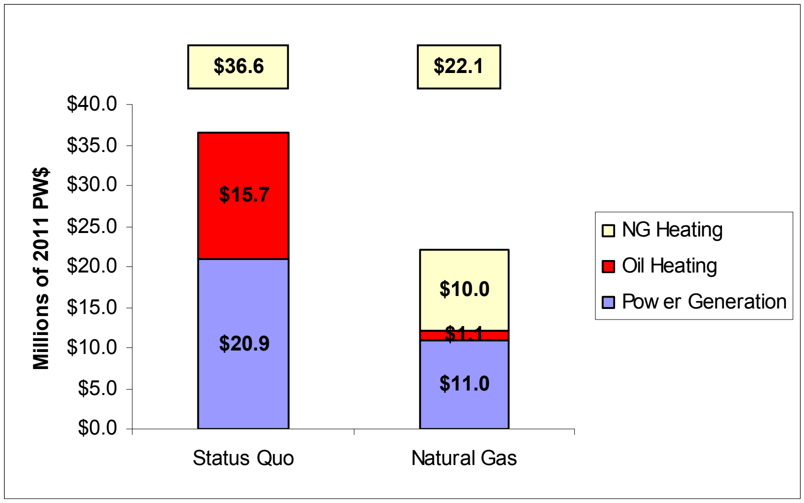
Figure 4-3
Sensitivity Analysis – Discount Rate of 15%



Nominally, the present value of the benefit associated with a conversion to natural gas decreases to $3.5 million, but on a relative basis the status quo continues to be 52% more expensive than a conversion to natural gas.

Conversely, if the discount rate is reduced to 5%, the present value of the savings increases to $14.5 million, while the relative cost of the status quo increases to a level that is 66% higher than the conversion to natural gas.

Figure 4-4
Sensitivity Analysis – Discount Rate of 5%



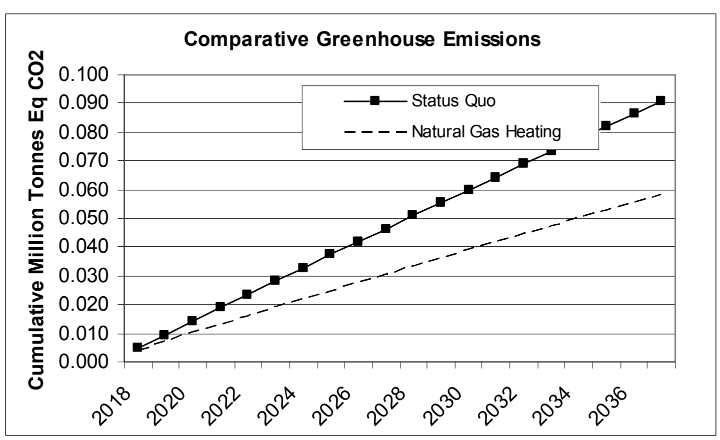
4.4. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were excluded from the analysis and recovered in global tolls paid by all shippers, the net benefit of the conversion to Natural Gas would increase by $1.4 million to $8.2 million.

4.5. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 2,200 tonnes or 24% in the first year following conversion, increasing to 33,000 tonnes or 36% through the Analysis Period.

Figure 4-5
Greenhouse Gas Emissions



5.0 Tulita

5.1. Key Assumptions

5.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Tulita for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 3,105 litres of heating oil per year, while the average commercial building consumes 6,278 litres per year. By 2019, it is assumed that there will be 177 residential accounts and 71 commercial accounts in Tulita, increasing to 185 and 74 by 2038. Under the Status Quo, it is assumed that 33.3 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 30.7 million litres.

5.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

5.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 7 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains was taken from the 2008 Encor Study. Specific capital costs are outlined in Table 1-2, and in Appendix B.

5.1.4. Cost to Convert Power Generation to Natural Gas

In accordance with the Associated Engineering Study completed in 2011, the capital cost for conversion to natural gas fired generators is estimated at $3.75 million.

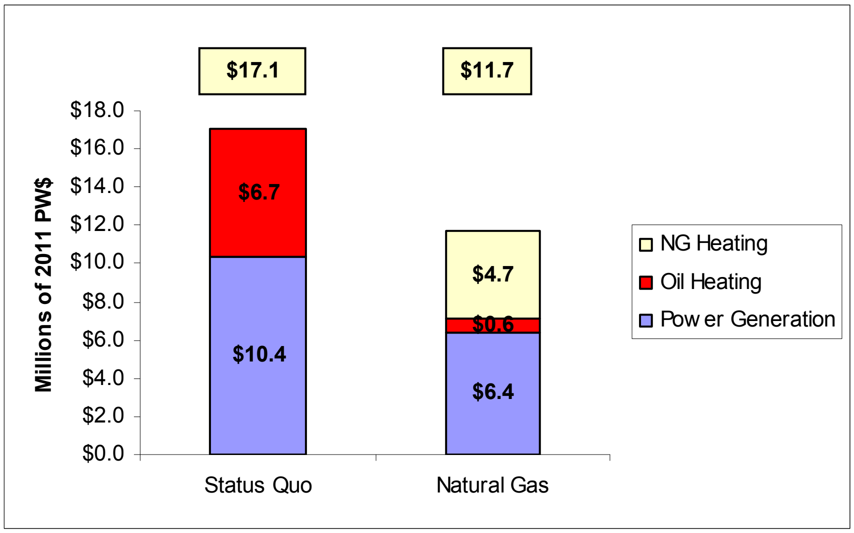
5.1.5. O&M Costs

Annual O&M cost are assumed to average approximately $702,000 in present value terms, of which approximately 90% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

5.2. Analysis Results

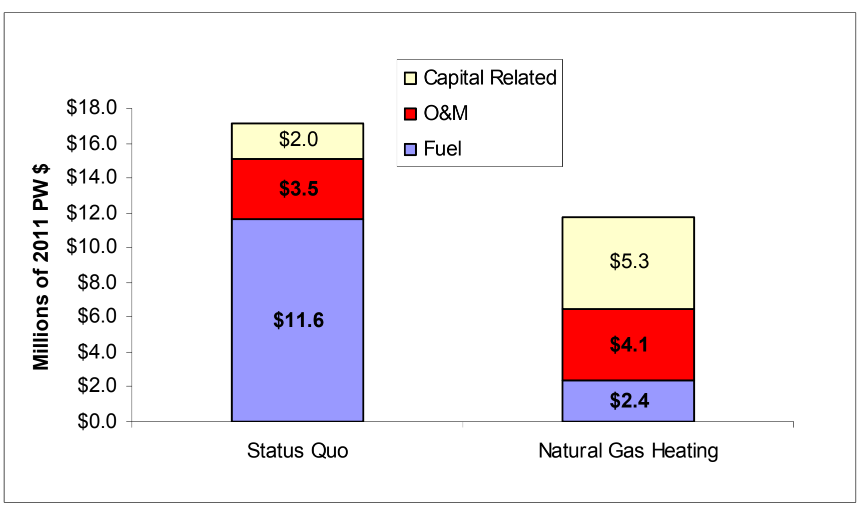
The updated analysis for Tulita continues to demonstrate a highly favourable return from a conversion to natural gas for heating and power generation, as illustrated in the graph below. This graph indicates that the present value of the Status Quo option is $17.1 million, a premium of $5.4 million or 46% relative to the present value of the costs associated with a conversion to natural gas.

Figure 5-1
NPV Comparison of Status Quo and Conversion to Natural Gas



The vast majority of these overall savings can be attributed to savings in commodity costs over the Analysis Period. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $9.2 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 5-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would also disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

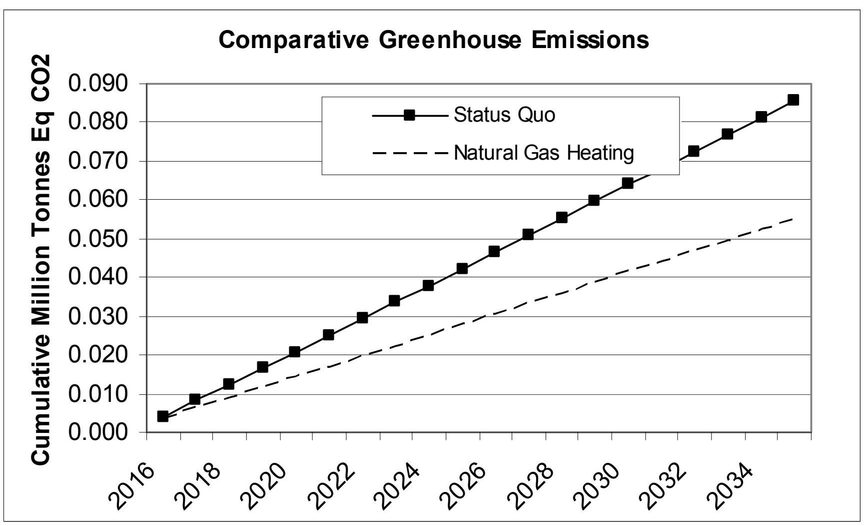
5.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were excluded from the analysis and recovered in global tolls paid by all shippers, the net benefit of the conversion to Natural Gas would increase by $1.4 million to $6.8 million.

5.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 1,900 tonnes or 23% in the first year following conversion, increasing to 31,000 tonnes or 36% through the Analysis Period.

Figure 5-3
Greenhouse Gas Emissions



6.0 Fort Simpson

6.1. Key Assumptions

6.1.1. Residential & Non-Residential Heating Oil Use per Building

Data on fuel oil use for heating purposes was not available, so consumption levels per building were assumed to mirror the consumption levels in Tulita. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.14 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 2,232 litres of heating oil per year, while the average commercial building consumes 10,213 litres per year. By 2019, it is assumed that there will be 516 residential accounts and 145 commercial accounts in Fort Simpson, decreasing to 508 and 142 by 2038. Under the Status Quo, it is assumed that 91.7 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 88.9 million litres.

6.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 80% of both residential and commercial customers will convert to natural gas heating over a 6 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

6.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 20 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 4” will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains was taken from the 2010 CGSI Report. Specific capital costs are outlined in Table 1-2, and in Appendix B.

6.1.4. Cost to Convert Power Generation to Natural Gas

In accordance with the 2010 CGSI Study, the capital cost for conversion to natural gas fired generators in Fort Simpson is estimated at $11.2 million.

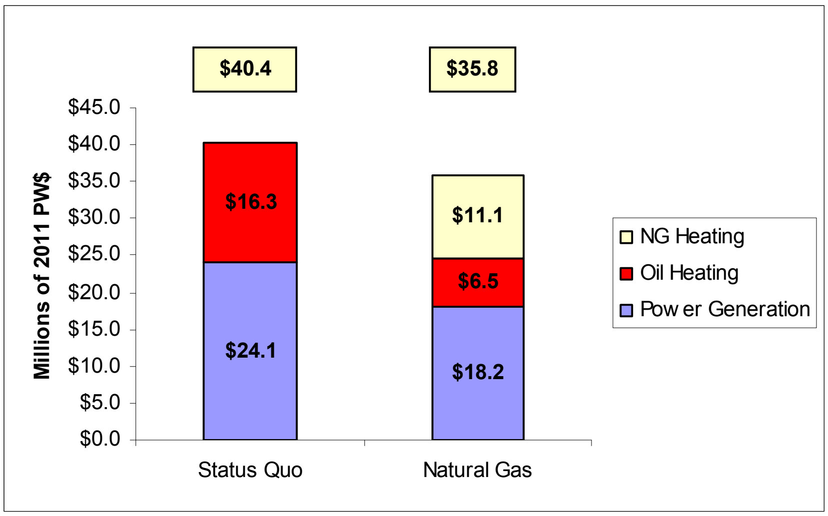
6.1.5. O&M Costs

Annual O&M cost are assumed to average approximately $1.87 million in present value terms, of which approximately 88% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

6.2. Analysis Results

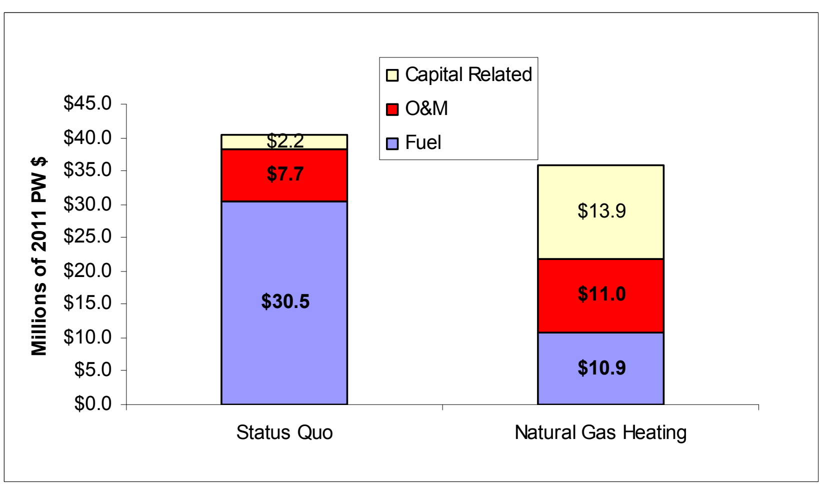
The updated analysis for Fort Simpson continues to demonstrate a favourable return from a conversion to natural gas for heating and power generation, as illustrated in the graph below. This graph indicates that the present value of the Status Quo option is $40.4 million, a premium of $4.6 million or over 13% relative to the present value of the costs associated with a conversion to natural gas.

Figure 6-1
NPV Comparison of Status Quo and Conversion to Natural Gas



The vast majority of these overall savings can be attributed to savings in commodity costs over the Analysis Period. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $19.6 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 6-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would also disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

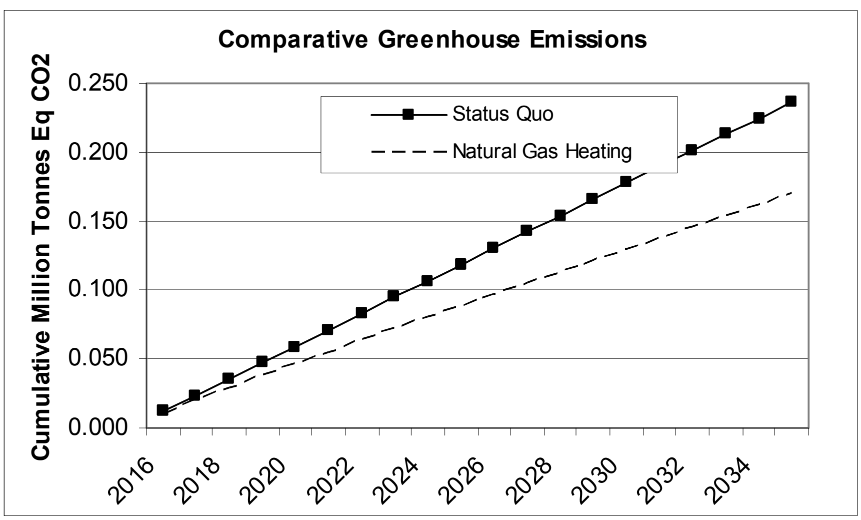
6.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were excluded from the analysis and recovered in global tolls paid by all shippers, the net benefit of the conversion to Natural Gas would increase by $1.4 million to $6.0 million.

6.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 3,700 tonnes or 16% in the first year following conversion, increasing to 66,000 tonnes or 28% through the Analysis Period.

Figure 6-3
Greenhouse Gas Emissions



7.0 Norman Wells

7.1. Key Assumptions

7.1.1. Purpose of the Analysis

Inuvik and Normal Wells represent unique cases among the 13 communities included in this analysis, based on the fact that laterals have already been constructed from nearby gas fields to these communities. Both communities have also constructed gas distribution systems to facilitate the conversion of the heating and hot water load to natural gas. As a result, the standard analysis being undertaken for the other communities in this Study is not applicable, as there is no oil heating or power generation load to displace.

Therefore, no economic feasibility analysis has been performed for Norman Wells. The focus of the Study for this community has been to estimate:

1. The demand for natural gas over the analysis period
2. The capital costs associated with converting gas supply from the existing wells to the MGP

Armed with this data, GNWT can determine whether the costs to connect to the MGP are justified based on:

- Security of supply
- Relative commodity costs between the MGP and the current source of gas
- Relative O&M costs between the current gas supply system and the proposed Lateral, CTS and Community Gate Station
- The cost of generating power using natural gas fired generators operated by NTPC, versus the cost of purchasing power from Imperial Oil (the status quo).

7.1.2. Residential & Non-Residential Heating Oil Use per Building

Data on natural gas use for heating purposes was not available, so consumption levels per building were assumed to mirror the equivalent oil-based consumption levels in Tulita. To categorize this use into residential and non-residential components, it was assumed that consumption of heating fuel occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, it is assumed that the average residential building consumes natural gas equivalent to 1,962 litres of heating oil per year, while the average commercial building consumes the equivalent of 9,058 litres of heating oil per year. By 2019, it is assumed that there will be 398 residential accounts and 152 commercial accounts in Norman Wells, increasing to 413 and 158 by 2038. Under the Status Quo, it is assumed that 92.9 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 88.6 million litres.

7.1.3. Conversions – Pace & Saturation

Given that Normal Wells already provides natural gas to its residents for heating and hot water, it is assumed that 100% of both residential and commercial customers have already converted to natural gas. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

7.1.4. Capital Cost for Lateral

The analysis assumes that the community gate station (the second PRS) will be located 1 kilometre from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. Specific capital costs are outlined in Table 1-2, and in Appendix B.

7.1.5. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 2,120 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $7.2 million. However, this cost is only applicable in the event that electricity requirements are no longer satisfied through Imperial Oil. Therefore, for purposes of Table 1-2, this cost has been classified as "n/a".

7.1.6. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2008 and 2010 CGSI Studies, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Norman Wells results in an estimated cost of $1,970 per account.

Incremental O&M costs for the lateral, Custody Transfer Station and Community Gate Station are expected to total approximately $73,000 per year.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies.

7.1.7. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

7.2. *Cost and Demand Summary*

Key costs associated with the conversion of the gas supply for Norman Wells to the MGP are as follows:

- Custody Transfer Station $1.30 million
- Lateral $ .27 million
- Community Gate Station $ .73 million
- Generation Conversion (if applicable) $7.21 million
- Incremental Annual O&M $ .073 million

Assuming that electricity demand continues to be met through purchases from Imperial oil, demand for natural gas supplied to Norman Wells from the MGP is expected to be approximately 57,700 GJ in 2021, increasing to 59,500 GJ in 2038.

8.0 Tuktoyaktuk

8.1. Key Assumptions

8.1.1. Residential & Non-Residential Heating Oil Use per Building

Data on fuel oil use by Tuktoyaktuk for heating purposes was taken from the 2011 Brackman Energy Consulting Study. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 2,118 litres of heating oil per year, while the average commercial building consumes 6,735 litres per year. By 2019, it is assumed that there will be 323 residential accounts and 74 commercial accounts in Tuktoyaktuk, decreasing to 279 and 63 by 2038. Under the Status Quo, it is assumed that 42.2 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 39.6 million litres.

8.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

8.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 150 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 3" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Tuktoyaktuk. Specific capital costs are outlined in Table 1-2, and in Appendix B.

8.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 2,205 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $7.5 million.

8.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Tuktoyaktuk results in an estimated cost of $2,050 per account.

Annual O&M cost are assumed to average approximately $2.8 million in present value terms, of which approximately 60% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

8.1.6. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

8.1.7. Fuel Storage Capacity

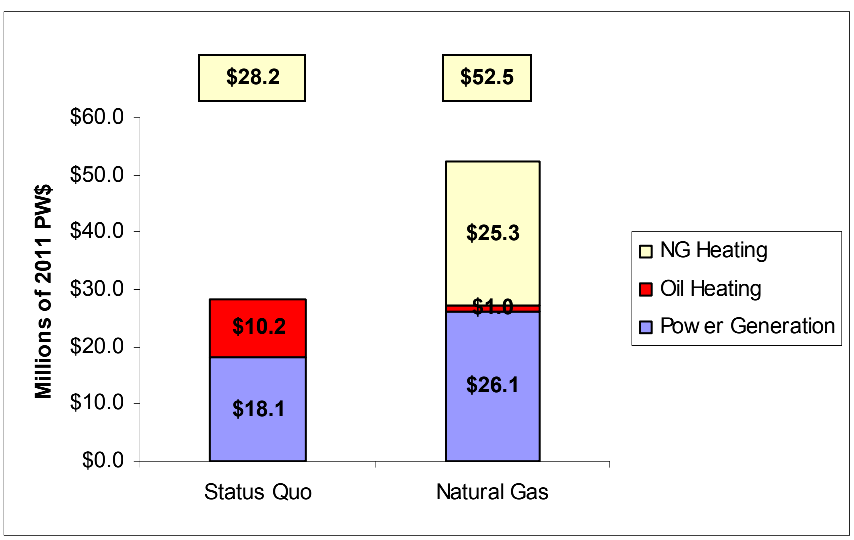
Fuel storage capacity has been estimated based on the ratio of fuel storage to annual generation applicable to Fort Simpson, pro rated for the annual generation applicable to Tuktoyaktuk.

8.2. Analysis Results

The analysis for Tuktoyaktuk demonstrates that the conversion to natural gas is not economically viable without the exclusion of significant capital costs, as reflected in the graph below. This graph indicates that the present value of the Status Quo option is $28.2 million, which is $24.3 million or 46% lower than the present value of the costs associated with a conversion to natural gas.

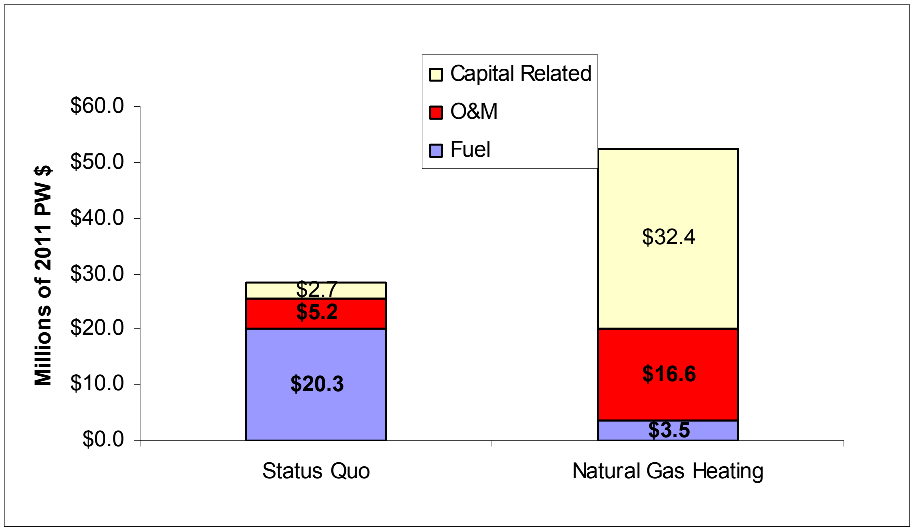
Figure 8-1

NPV Comparison of Status Quo and Conversion to Natural Gas



Although the commodity cost differential would result in savings from a conversion to natural gas, these fuel cost savings are more than offset by the higher levels of capital and O&M costs incurred due largely to the significantly longer distance between this community and the Mackenzie Valley Pipeline. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $16.8 million versus the present value of commodity and O&M costs if heating and generation were to remain on diesel.

Figure 8-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

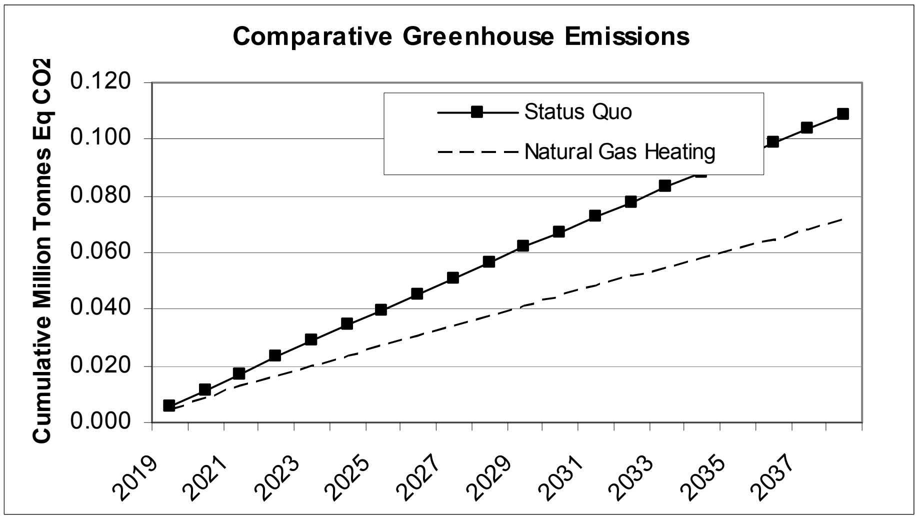
8.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $51.1 million, which would still leave a shortfall of $22.9 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Tuktoyaktuk to natural gas.

8.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 2,800 tonnes or 24% in the first year following conversion, increasing to 38,000 tonnes or 35% through the Analysis Period.

Figure 8-3
Greenhouse Gas Emissions



9.0 Wrigley

9.1. Key Assumptions

9.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Wrigley for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Due to the smaller size of the population in Wrigley, it is assumed that no multi-family units exist, and that 1.00 accounts per building for both residential and commercial customers. On this basis, the analysis assumes that the average residential building consumes 1,872 litres of heating oil per year, while the average commercial building consumes 3,417 litres per year. By 2019, it is assumed that there will be 55 residential accounts and 37 commercial accounts in Wrigley, decreasing to 47 and 31 by 2038. Under the Status Quo, it is assumed that 7.8 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 7.2 million litres.

9.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

9.1.3. Capital Cost for Lateral & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 5 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Wrigley. Specific capital costs are outlined in Table 1-2, and in Appendix B.

9.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 781 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $2.66 million.

9.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the lower account population of Wrigley results in an estimated cost of $2,770 per account.

Annual O&M cost are assumed to average approximately $394,000 in present value terms, of which approximately 85% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

9.1.6. Plant-in-Service Data

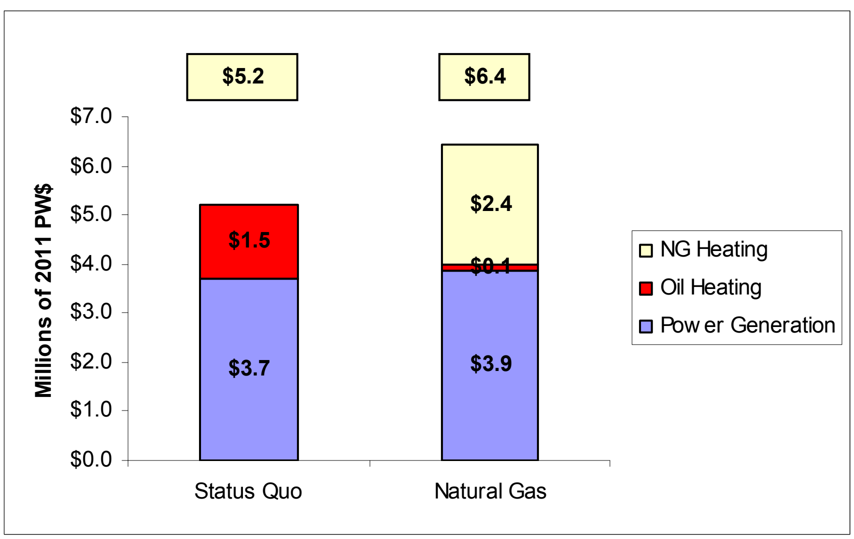
Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

9.2. Analysis Results

The analysis for Wrigley demonstrates that the conversion to natural gas is not economically viable without the exclusion of some capital costs, as reflected in the graph below. This graph indicates that the present value of the Status Quo option is $5.2 million, which is $1.2 million or 19% lower than the present value of the costs associated with a conversion to natural gas.

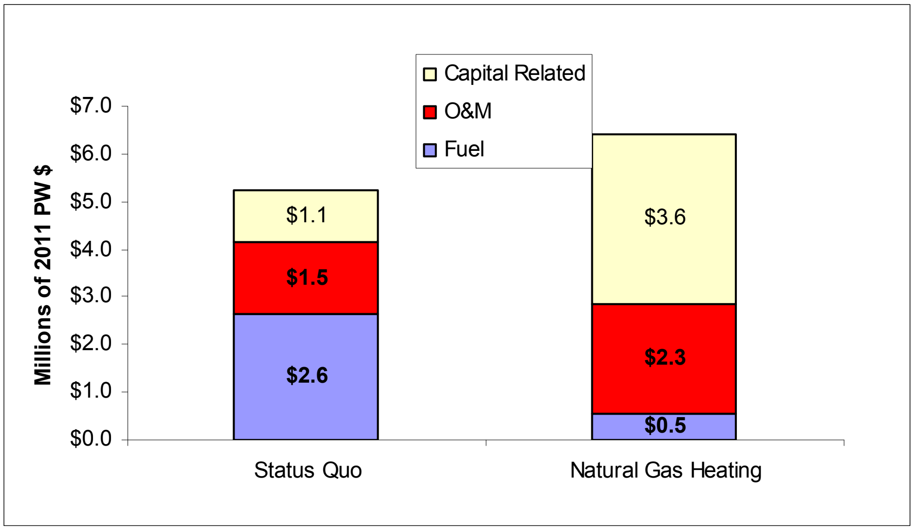
Figure 9-1

NPV Comparison of Status Quo and Conversion to Natural Gas



Although the commodity cost differential would result in savings from a conversion to natural gas, these fuel cost savings are more than offset by the high level of capital costs relative to the size of the community and the corresponding rates of fuel consumption. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $2.1 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 9-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

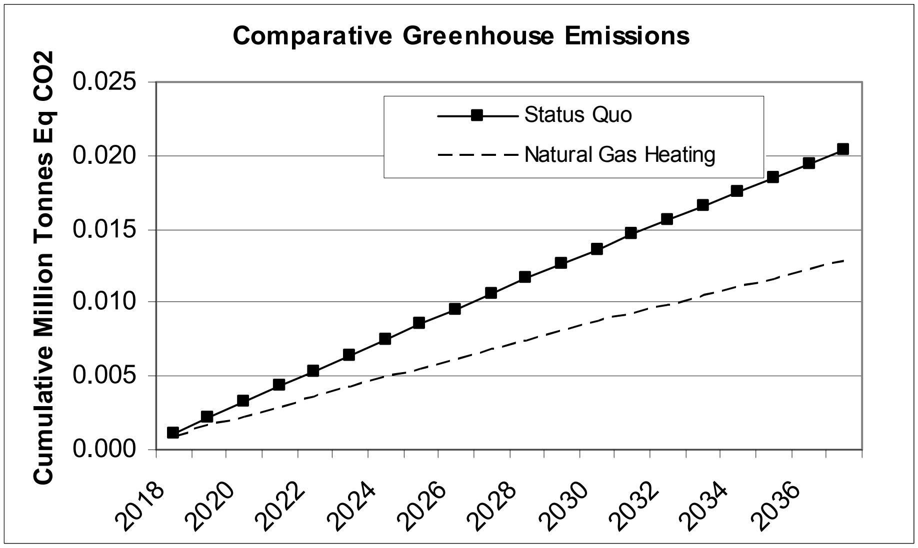
9.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the conversion to natural gas in Wrigley would become economically viable. Under this scenario, the present value of costs associated with the conversion to natural gas would drop to $5.0 million, a savings of $.2 million or 4% relative to the status quo.

9.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate savings in greenhouse gas emissions that are estimated at 500 tonnes or 24% by the end of the first year following conversion, increasing to 7,000 tonnes or 35% through the Analysis Period.

Figure 9-3
Greenhouse Gas Emissions



10.0 Fort McPherson

10.1. Key Assumptions

10.1.1. Residential & Non-Residential Heating Oil Use per Building

Data on fuel oil use for heating purposes was not available, so consumption levels per building were assumed to mirror the consumption levels in Tulita. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 2,563 litres of heating oil per year, while the average commercial building consumes 10,524 litres per year. By 2019, it is assumed that there will be 282 residential accounts and 62 commercial accounts in Fort McPherson, decreasing to 263 and 58 by 2038. Under the Status Quo, it is assumed that 43.9 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 40.7 million litres.

This Study does not consider the impact of the Residual Heat Project, in which NTPC is a 50% partner, on the heating load requirements in the community.

10.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

10.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 140 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 3” will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Fort McPherson. Specific capital costs are outlined in Table 1-2, and in Appendix B.

10.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 1,825 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $6.2 million.

10.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Fort McPherson results in an estimated cost of $2,080 per account.

Annual O&M cost are assumed to average approximately $2.5 million in present value terms, of which approximately 59% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

10.1.6. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

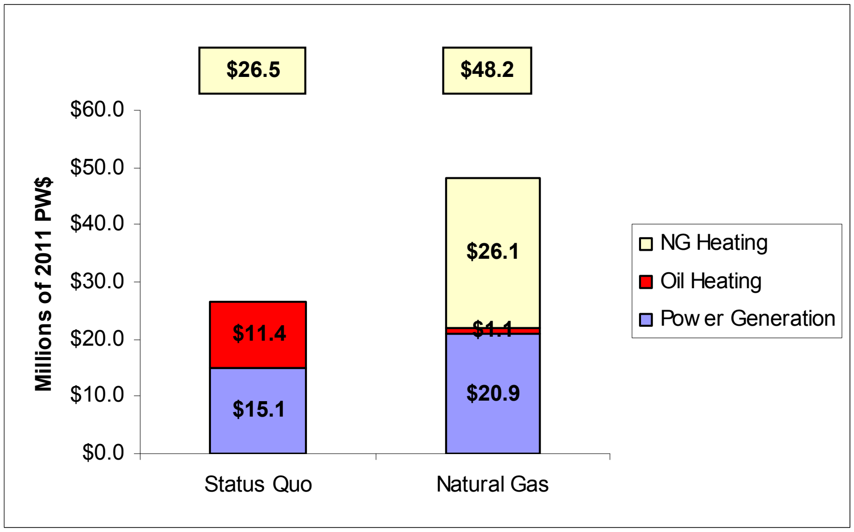
10.1.7. Fuel Storage Capacity

Fuel storage capacity has been estimated based on the ratio of fuel storage to annual generation applicable to Fort Simpson, pro rated for the annual generation applicable to Fort McPherson.

10.2. Analysis Results

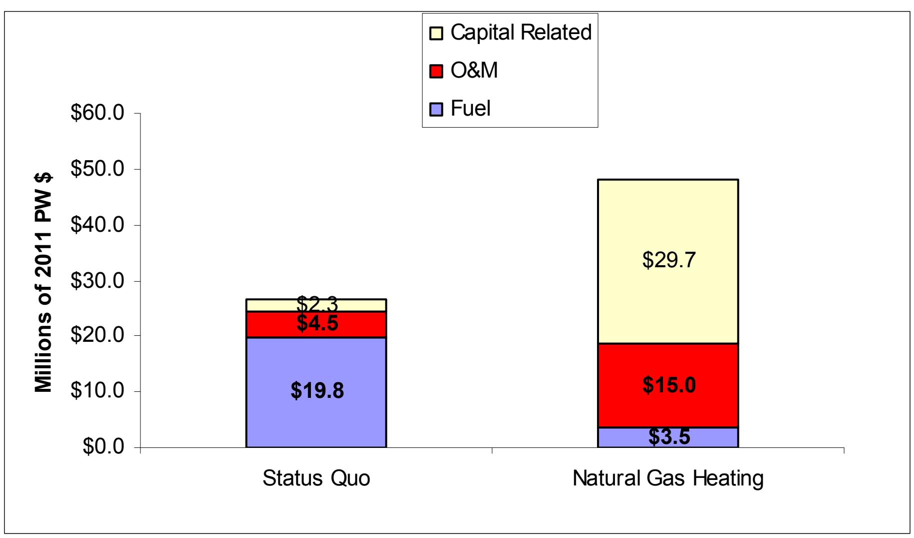
The analysis for Fort McPherson demonstrates that the conversion to natural gas is not economically viable without the exclusion of significant capital costs, as reflected in the graph below. This graph indicates that the present value of the Status Quo option is $26.5 million, which is $21.7 million or 45% lower than the present value of the costs associated with a conversion to natural gas.

Figure 10-1
NPV Comparison of Status Quo and Conversion to Natural Gas



Although the commodity cost differential would result in savings from a conversion to natural gas, these fuel cost savings are more than offset by the high level of capital and O&M costs incurred due largely to the significantly longer distance between this community and the Mackenzie Valley Pipeline. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $16.3 million versus the present value of commodity and O&M costs if heating and generation were to remain on diesel.

Figure 10-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

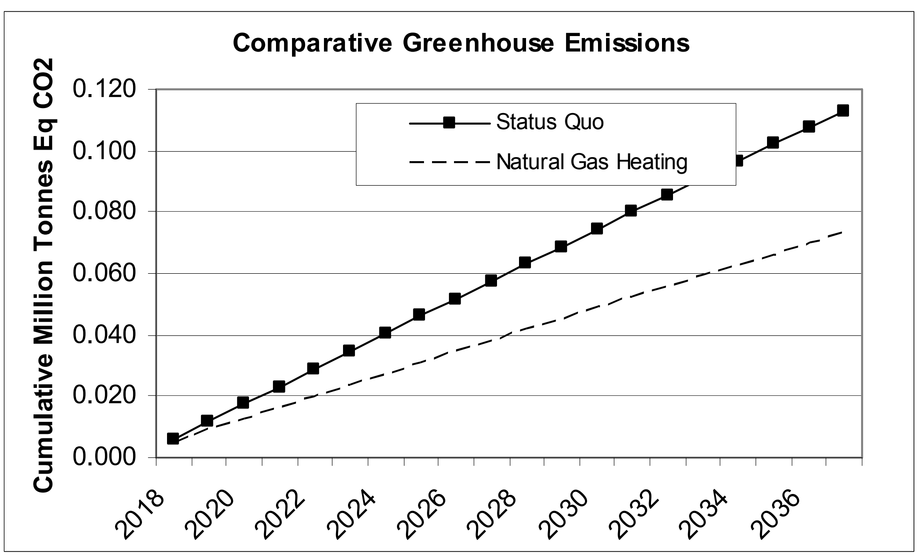
10.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $46.8 million, which would still leave a shortfall of $20.3 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Fort McPherson to natural gas.

10.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 2,700 tonnes or 23% in the first year following conversion, increasing to 40,000 tonnes or 35% through the Analysis Period.

Figure 10-3
Greenhouse Gas Emissions



11.0 Aklavik

11.1. Key Assumptions

11.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Aklavik for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 485 litres of heating oil per year, while the average commercial building consumes 1,559 litres per year. By 2019, it is assumed that there will be 261 residential accounts and 74 commercial accounts in Aklavik, increasing to 267 and 75 by 2038. Under the Status Quo, it is assumed that 21.4 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 21 million litres.

11.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

11.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 90 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Aklavik. Specific capital costs are outlined in Table 1-2, and in Appendix B.

11.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 1,280 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $4.4 million.

11.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Aklavik results in an estimated cost of $2,100 per account.

Annual O&M cost are assumed to average approximately $1.5 million in present value terms, of which approximately 68% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

11.1.6. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

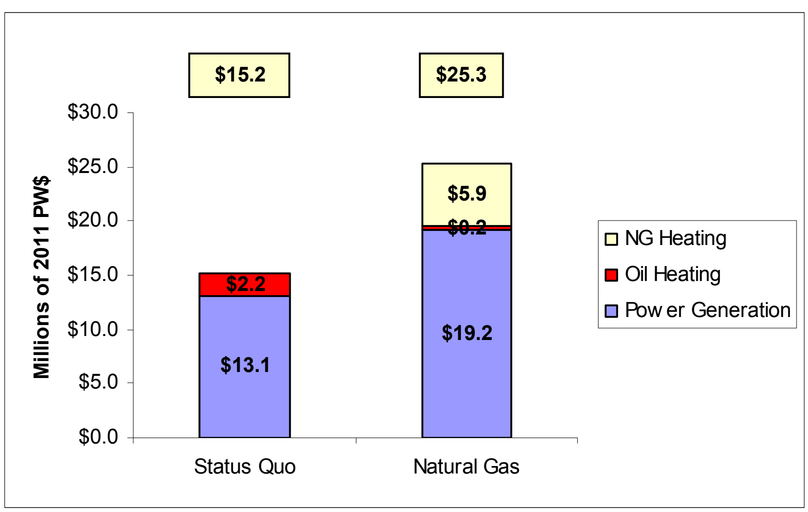
11.1.7. Fuel Storage Capacity

Fuel storage capacity has been estimated based on the ratio of fuel storage to annual generation applicable to Fort Simpson, pro rated for the annual generation applicable to Aklavik.

11.2. Analysis Results

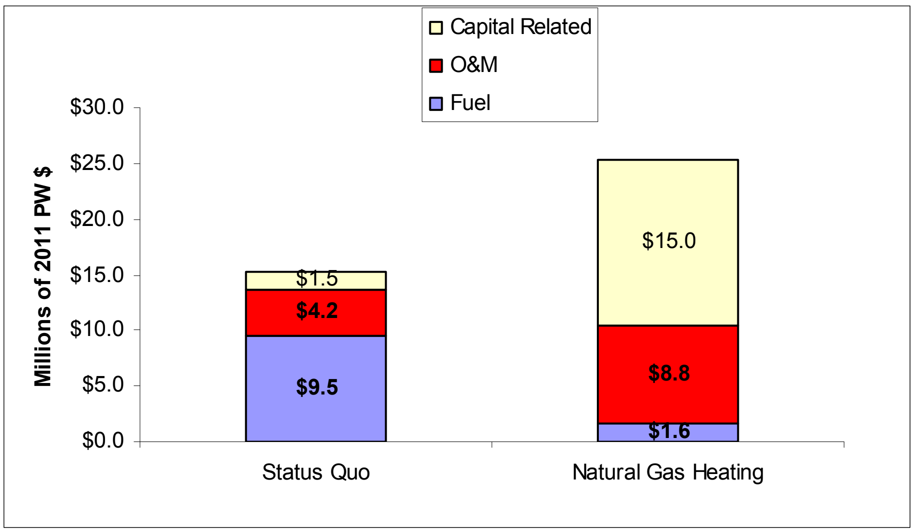
The analysis for Aklavik demonstrates that the conversion to natural gas is not economically viable without the exclusion of significant capital costs, as reflected in the graph below. This graph indicates that the present value of the Status Quo option is $15.2 million, which is $10.1 million or 40% lower than the present value of the costs associated with a conversion to natural gas.

Figure 11-1
NPV Comparison of Status Quo and Conversion to Natural Gas



Although the commodity cost differential would result in savings from a conversion to natural gas, these fuel cost savings are more than offset by the high level of capital and O&M costs incurred due largely to the significantly longer distance between this community and the Mackenzie Valley Pipeline. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $7.9 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 11-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

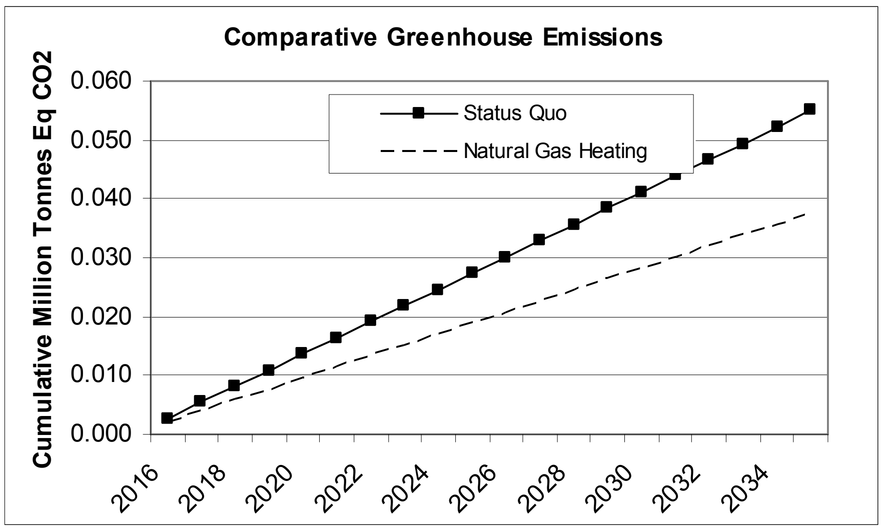
11.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $23.9 million, which would still leave a shortfall of $8.7 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Aklavik to natural gas.

11.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 1,400 tonnes or 26% in the first year following conversion, increasing to 17,000 tonnes or 31% through the Analysis Period.

Figure 11-3
Greenhouse Gas Emissions



12.0 Deline

12.1. Key Assumptions

12.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Deline for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 2,406 litres of heating oil per year, while the average commercial building consumes 8,257 litres per year. By 2019, it is assumed that there will be 220 residential accounts and 56 commercial accounts in Deline, decreasing marginally to 219 and 56 by 2038. Under the Status Quo, it is assumed that 33.1 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 30.8 million litres.

12.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

12.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 110 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 3" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Deline. Specific capital costs are outlined in Table 1-2, and in Appendix B.

12.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 1,140 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $3.9 million.

12.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Deline results in an estimated cost of $2,140 per account.

Annual O&M cost are assumed to average approximately $1.97 million in present value terms, of which approximately 58% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

12.1.6. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

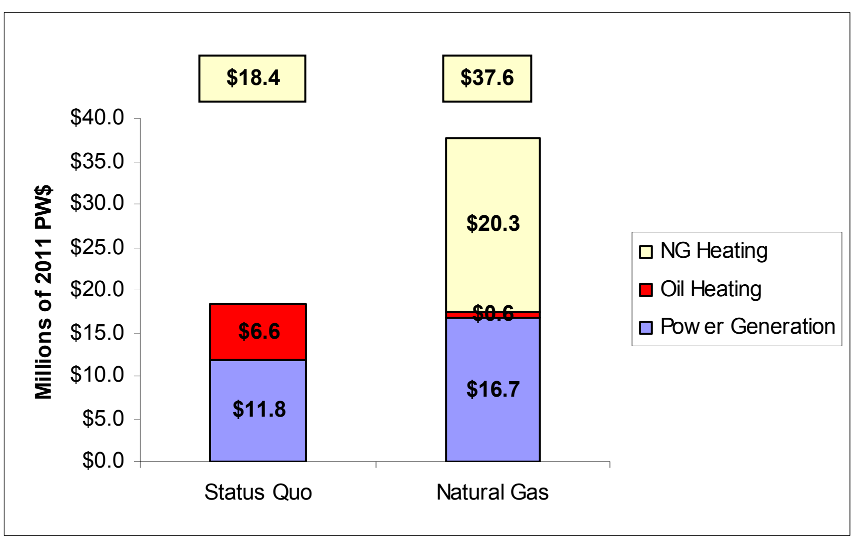
12.1.7. Fuel Storage Capacity

Fuel storage capacity has been determined utilizing information provided by GNWT.

12.2. Analysis Results

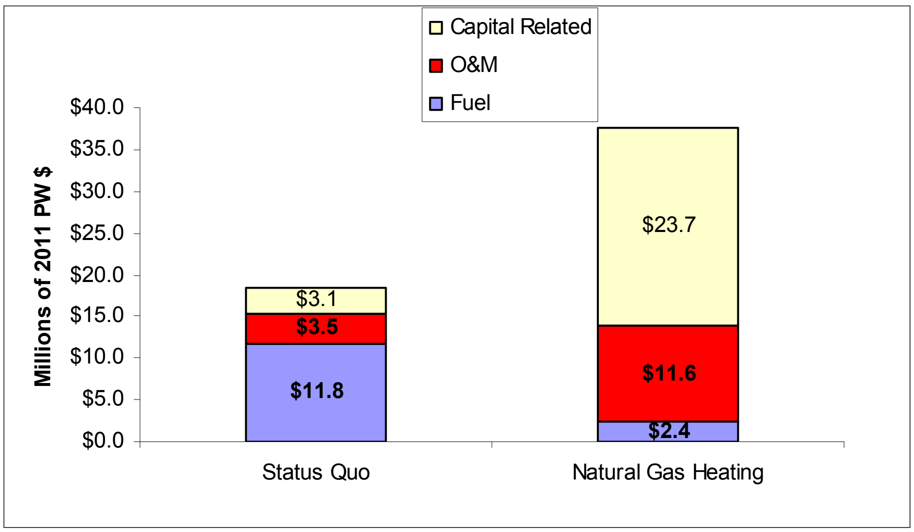
The analysis for Deline demonstrates that the conversion to natural gas is not economically viable without the exclusion of significant capital costs, as reflected in the graph below. This graph indicates that the present value of the Status Quo option is $18.4 million, which is $19.2 million or 51% lower than the present value of the costs associated with a conversion to natural gas.

Figure 12-1
NPV Comparison of Status Quo and Conversion to Natural Gas



Although the commodity cost differential would result in savings from a conversion to natural gas, these fuel cost savings are more than offset by the high level of capital and O&M costs incurred due largely to the significantly longer distance between this community and the Mackenzie Valley Pipeline. As noted in the graph below, the present value of commodity costs following a conversion to natural gas are expected to represent a savings of $9.4 million versus the present value of commodity costs if heating and generation were to remain on diesel.

Figure 12-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

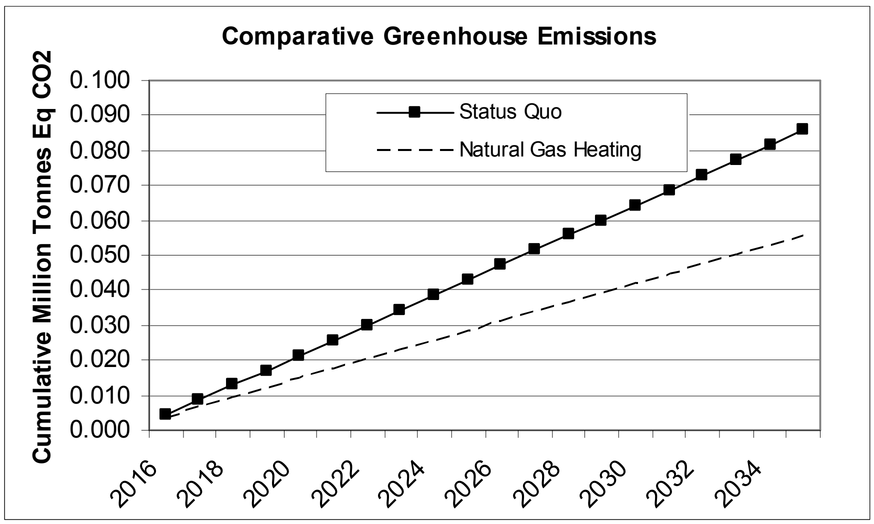
12.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $36.2 million, which would still leave a shortfall of $17.8 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Deline to natural gas.

12.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate cumulative savings in greenhouse gas emissions that are estimated at 2,000 tonnes or 24% in the first year following conversion, increasing to 30,000 tonnes or 35% through the Analysis Period.

Figure 12-3
Greenhouse Gas Emissions



13.0 Jean Marie River

13.1. Key Assumptions

13.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel by Jean Marie River for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Due to the smaller size of the population in Jean Marie River, it is assumed that no multi-family units exist, and that 1.00 accounts per building for both residential and commercial customers. On this basis, the analysis assumes that the average residential building consumes 1,638 litres of heating oil per year, while the average commercial building consumes 2,628 litres per year. By 2019, it is assumed that there will be 23 residential accounts and 15 commercial accounts in Jean Marie River, decreasing to 20 and 13 by 2038. Under the Status Quo, it is assumed that 2.9 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 2.7 million litres.

13.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

13.1.3. Capital Cost for Lateral & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 25 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Jean Marie River. Specific capital costs are outlined in Table 1-2, and in Appendix B.

13.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 230 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $782,000.

13.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the lower account population of Jean Marie River results in an estimated cost of $3,340 per account.

Annual O&M cost are assumed to average approximately $392,000 in present value terms, of which approximately 59% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

13.1.6. Plant-in-Service Data

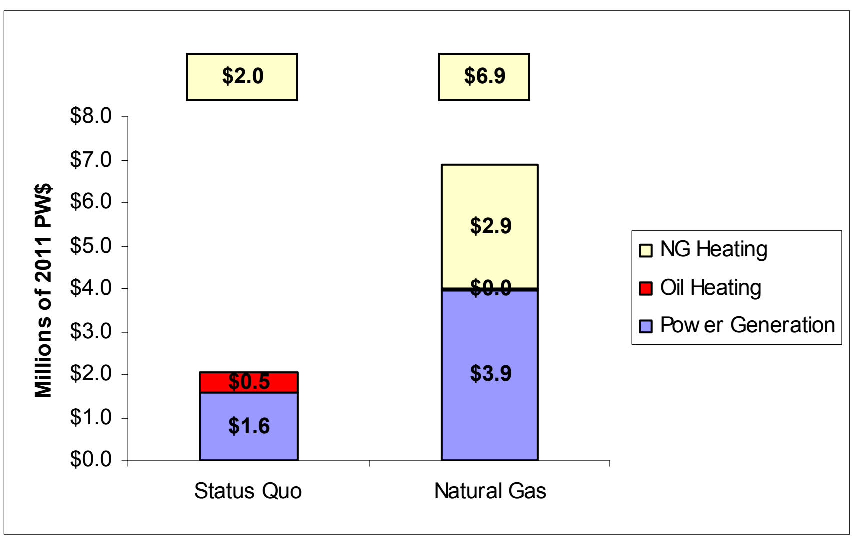
Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

13.2. Analysis Results

The analysis for Jean Marie River demonstrates that the conversion to natural gas will not be economically viable regardless of the level of capital cost exclusion, as reflected in the graphs below. Figure 13-1 indicates that the present value of the Status Quo option is $2 million, which is 4.9 million or 71% lower than the present value of the costs associated with a conversion to natural gas.

Figure 13-1

NPV Comparison of Status Quo and Conversion to Natural Gas



Although the capital cost of the lateral and pressure reducing stations exceeds this $4.9 million differential, this phenomena occurs due to the fact that the regulated return on capital for the natural gas utility is lower than the discount rate applied to the future cash flows. When applied to a standard

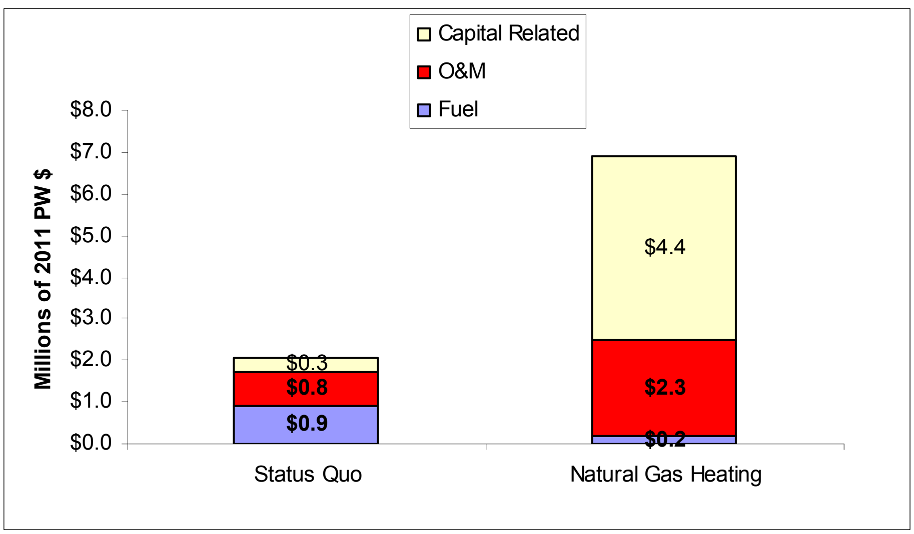
Utility Model, this has the effect of reducing the present value of the capital costs recovered to levels below the original capital costs themselves; thus skewing the comparison between the NPV of the options and the capital cost inputs.

In order for a capital exclusion to alter the viability of the project, there must be an annual savings on combined Fuel and O&M costs after conversion to natural gas. The challenge lies in the fact that with only a small number of residential and commercial customers, there are an insufficient number of accounts over which to amortize the fixed O&M and Administrative costs associated with the conversion to natural gas, particularly the allocation for the replacement/refurbishment of the lateral and pressure reducing stations. Thus, the combined Fuel and O&M costs following conversion to natural gas are projected to be slightly higher than the combined Fuel and O&M costs associated with the Status Quo.

Without any savings in this category, it is impossible to recover the capital costs of the distribution mains and site services; thus rendering the conversion to natural gas uneconomic regardless of the level of capital that is excluded and recovered in tolls paid by all shippers on the MGP.

Figure 13-2

NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

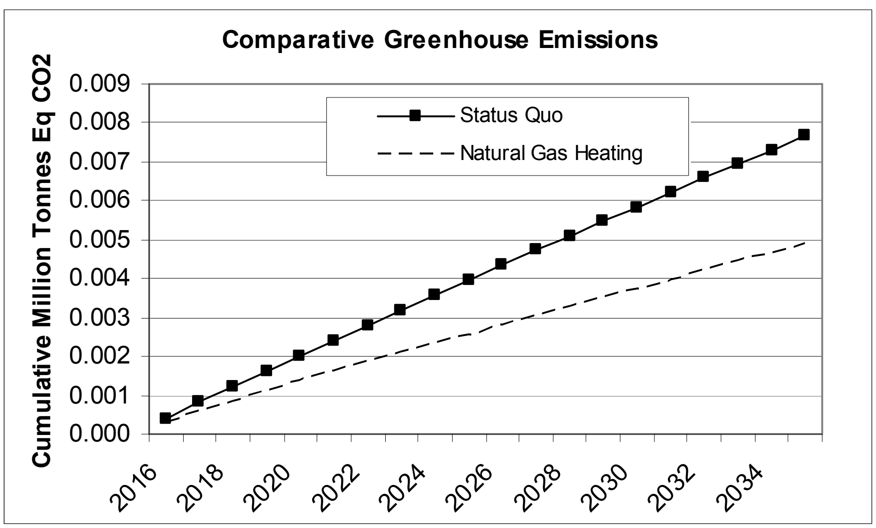
13.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $5.5 million, which would still leave a shortfall of $3.5 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Deline to natural gas.

13.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate savings in greenhouse gas emissions that are estimated at 200 tonnes or 25% by the end of the first year following conversion, increasing to 3,000 tonnes or 38% through the Analysis Period.

Figure 13-3
Greenhouse Gas Emissions



14.0 Tsiigehtchic

14.1. Key Assumptions

14.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel use by Tsiigehtchic for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Due to the smaller size of the population in Tsiigehtchic, it is assumed that no multi-family units exist, and that 1.00 accounts per building for both residential and commercial customers. On this basis, the analysis assumes that the average residential building consumes 2,254 litres of heating oil per year, while the average commercial building consumes 5,500 litres per year. By 2019, it is assumed that there will be 64 residential accounts and 32 commercial accounts in Tsiigehtchic, decreasing to 54 and 27 by 2038. Under the Status Quo, it is assumed that 10.1 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 9.0 million litres.

14.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

14.1.3. Capital Cost for Lateral & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 120 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Tsiigehtchic. Specific capital costs are outlined in Table 1-2, and in Appendix B.

14.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 500 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $1.7 million.

14.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the lower account population of Tsiigehtchic results in an estimated cost of $2,720 per account.

Annual O&M cost are assumed to average approximately $1.3 million in present value terms, of which approximately 52% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

14.1.6. Plant-in-Service Data

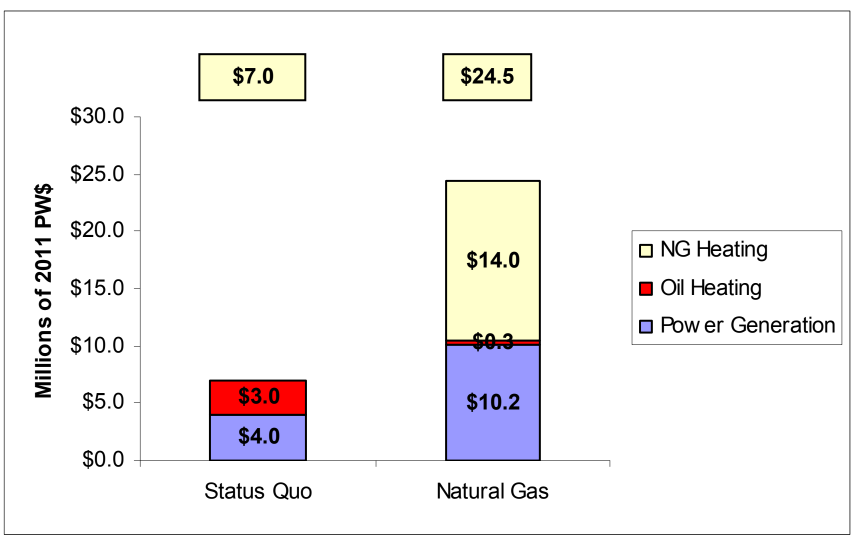
Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

14.2. Analysis Results

The analysis for Tsiigehtchic demonstrates that the conversion to natural gas will not be economically viable regardless of the level of capital exclusion, as reflected in the graphs below. Figure 14-1 indicates that the present value of the Status Quo option is $7 million, which is $17.5 million or 71% lower than the present value of the costs associated with a conversion to natural gas.

Figure 14-1

NPV Comparison of Status Quo and Conversion to Natural Gas



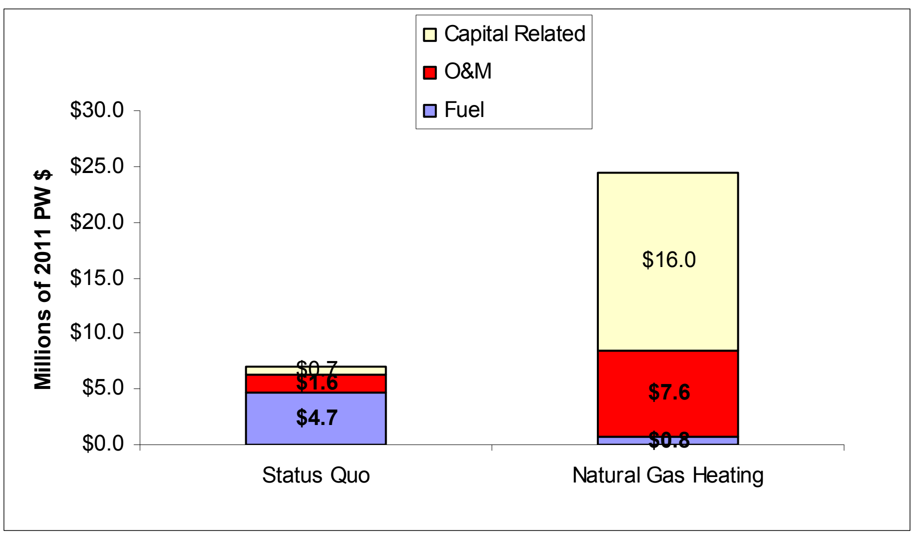
Although the capital cost of the lateral and pressure reducing stations exceeds this $17.5 million differential, this phenomena occurs due to the fact that the regulated return on capital for the natural gas utility is lower than the discount rate applied to the future cash flows. When applied to a standard

Utility Model, this has the effect of reducing the present value of the capital costs recovered to levels below the original capital costs themselves; thus skewing the comparison between the NPV of the options and the capital cost inputs.

In order for a capital exclusion to alter the viability of the project, there must be an annual savings on combined Fuel and O&M costs after conversion to natural gas. The challenge lies in the fact that there are an insufficient number of accounts over which to amortize the fixed O&M and Administrative costs associated with the conversion to natural gas, particularly the allocation for the replacement/refurbishment of the lateral and pressure reducing stations. Thus, the combined Fuel and O&M costs following conversion to natural gas are projected to be higher than the combined Fuel and O&M costs associated with the Status Quo.

Without any savings in this category, it is impossible to recover the capital costs of the distribution mains and site services; thus rendering the conversion to natural gas uneconomic regardless of the level of capital that is excluded from the analysis and recovered in tolls from all shippers on the MGP.

Figure 14-2
NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

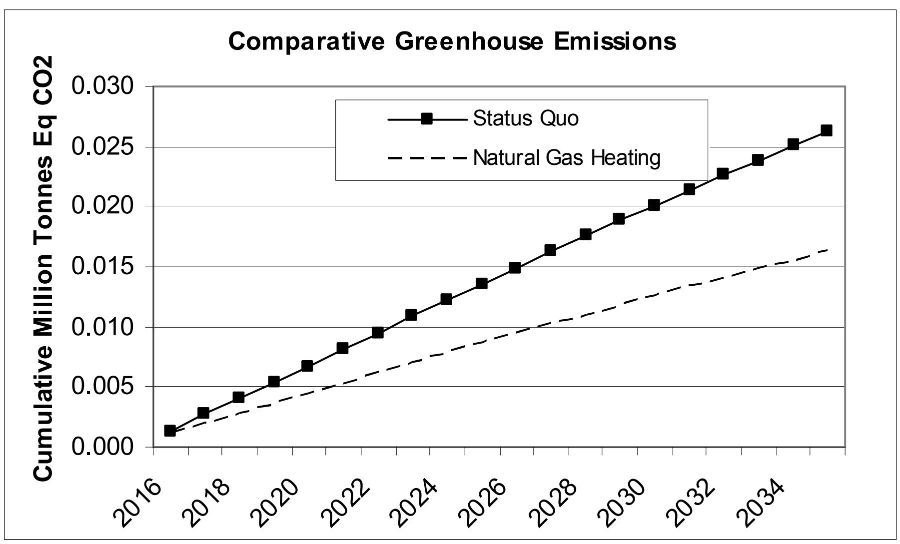
14.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $23.1 million, which would still leave a shortfall of $16.1 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Deline to natural gas.

14.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate savings in greenhouse gas emissions that are estimated at 700 tonnes or 26% by the end of the first year following conversion, increasing to 10,000 tonnes or 38% through the Analysis Period.

Figure 14-3
Greenhouse Gas Emissions



15.0 Colville Lake

15.1. Key Assumptions

15.1.1. Residential & Non-Residential Heating Oil Use per Building

GNWT has provided the total diesel used by Colville Lake for heating purposes. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Due to the smaller size of the population in Colville Lake, it is assumed that no multi-family units exist, and that 1.00 accounts per building for both residential and commercial customers. On this basis, the analysis assumes that the average residential building consumes 1,713 litres of heating oil per year, while the average commercial building consumes 5,855 litres per year. By 2019, it is assumed that there will be 40 residential accounts and 14 commercial accounts in Colville Lake, increasing to 46 and 17 by 2038. Under the Status Quo, it is assumed that 5.9 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 5.3 million litres.

15.1.2. Conversions – Pace & Saturation

Based on the 2008 Encor Study, it is assumed that 100% of both residential and commercial customers will convert to natural gas heating over a 3 year period. It is further assumed that 5% of the power generation requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

15.1.3. Capital Cost for Laterals & Distribution System

The analysis assumes that the community gate station (the second PRS) will be located 170 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 2" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. The cost of distribution mains is estimated by utilizing the cost for distribution mains in Tulita (per the 2008 Encor Study), pro-rated for the number of accounts in Colville Lake. Specific capital costs are outlined in Table 1-2, and in Appendix B.

15.1.4. Cost to Convert Power Generation to Natural Gas

Based on a generation conversion cost of $3,400 per kilowatt and an installed capacity of 240 kilowatts, the capital cost for conversion to natural gas fired generators is estimated at $816,000.

15.1.5. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an

average cost of $1,900 per account. Prorating the difference and projecting it to the lower account population of Colville Lake results in an estimated cost of $3,150 per account.

Annual O&M cost are assumed to average approximately $1.57 million in present value terms, of which approximately 45% is expected to be attributable to administrative costs, and the cost of operating the distribution system.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies. In the absence of data to the contrary, the fuel inventory level has been set at 38% based on experience in Fort Good Hope.

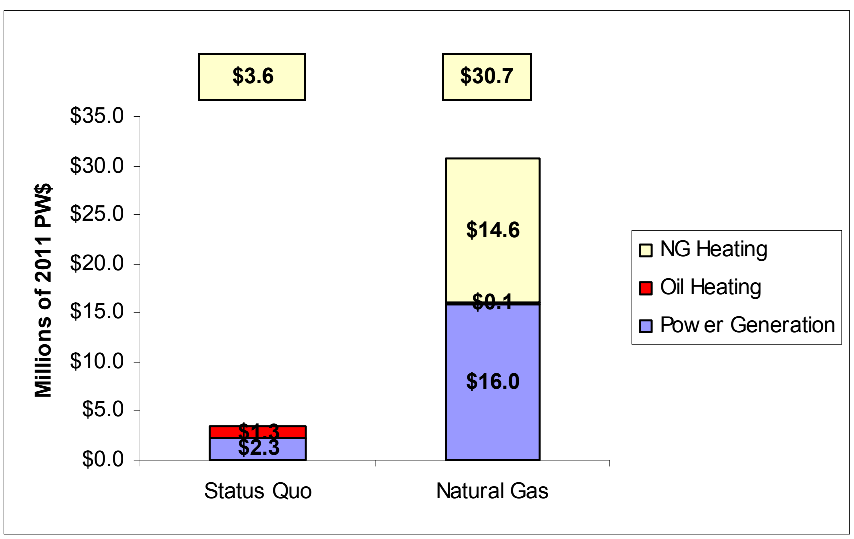
15.1.6. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

15.2. Analysis Results

The analysis for Colville Lake demonstrates that the conversion to natural gas will not be economically viable regardless of the level of capital cost exclusion, as reflected in the graphs below. Figure 15-1 illustrates that the present value of the Status Quo option is $3.6 million, which is $27.1 million or 88% lower than the present value of the costs associated with a conversion to natural gas.

Figure 15-1
NPV Comparison of Status Quo and Conversion to Natural Gas



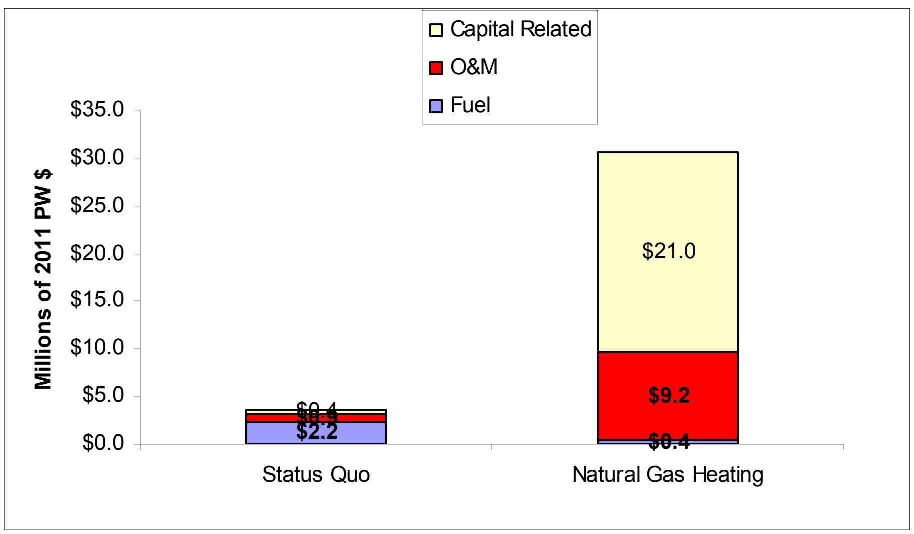
Although the capital cost of the lateral and pressure reducing stations exceeds this $27.1 million differential, this phenomena occurs due to the fact that the regulated return on capital for the natural gas utility is lower than the discount rate applied to the future cash flows. When applied to a standard Utility Model, this has the effect of reducing the present value of the capital costs recovered to levels below the original capital costs themselves; thus skewing the comparison between the NPV of the options and the capital cost inputs.

In order for a capital exclusion to alter the viability of the project, there must be an annual savings on combined Fuel and O&M costs after conversion to natural gas. The challenge lies in the fact that with the existing population of residential and commercial connections, there are an insufficient number of accounts over which to amortize the fixed O&M and Administrative costs associated with the conversion to natural gas, particularly the allocation for the replacement/refurbishment of the lateral and pressure reducing stations. Thus, although there would be a commodity cost savings of $1.8 million, this is more than offset by the higher O&M costs after conversion.

Without any savings in this category, it is impossible to recover the capital costs of the distribution mains and site services; thus rendering the conversion to natural gas uneconomic regardless of the level of capital costs that are excluded and rolled into tolls for all MGP shippers.

Figure 15-2

NPV Comparison of Capital Costs vs. Commodity and O&M Costs



If the analysis period were to extend into perpetuity, the negative capital cost differential associated with a conversion to natural gas would eventually disappear, reflecting the fact that once the initial costs of conversion are incurred, the ongoing capital costs associated with a operating a natural gas heating and generating system can reasonably be expected to be equal to or lower than the ongoing capital costs of operating a diesel based system.

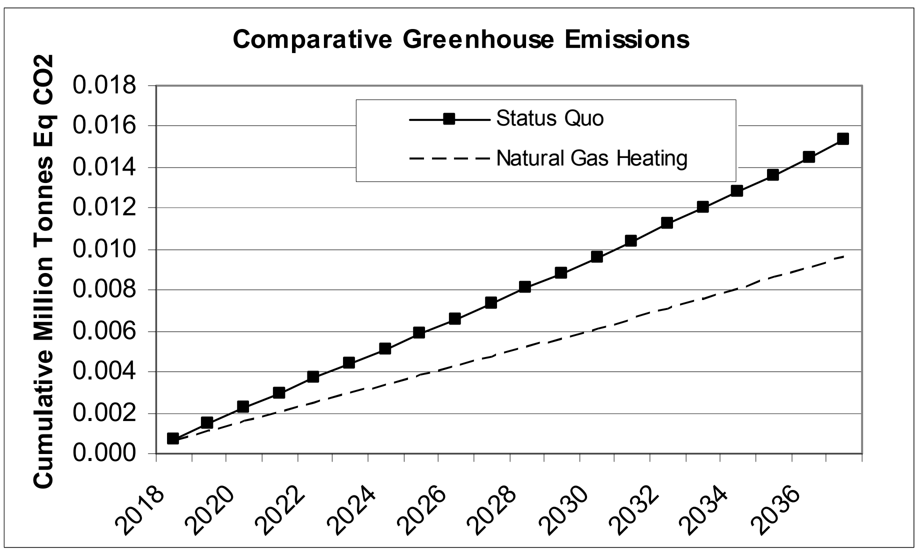
15.3. Contributions per CPCN

If 100% of the costs of the Custody Transfer Station and Community Gate Station were to be excluded from the analysis, and subsequently recovered in global tolls paid by all shippers, the present value of costs associated with the conversion to natural gas would drop to $29.3 million, which would still leave a shortfall of $25.7 million relative to the status quo. Therefore, the proposed capital exclusion under the CPCN will not be sufficient to ensure the economic feasibility of converting Deline to natural gas.

15.4. Environmental Impact

Although low sulphur diesel is a significantly cleaner burning fuel than diesel formulation utilized in the past, it continues to generate significantly more greenhouse gas emissions than an energy equivalent volume of natural gas. As illustrated in the following graph, a conversion to natural gas will generate savings in greenhouse gas emissions that are estimated at 300 tonnes or 21% by the end of the first year following conversion, increasing to 5,000 tonnes or 33% through the Analysis Period.

Figure 15-3
Greenhouse Gas Emissions



16.0 Inuvik

16.1. Key Assumptions

16.1.1. Purpose of the Analysis

Inuvik and Normal Wells represent unique cases among the 13 communities included in this analysis, based on the fact that laterals have already been constructed from nearby gas fields to these communities. Both communities have also constructed gas distribution systems to facilitate the conversion of the heating and hot water load to natural gas. As a result, the standard analysis being undertaken for the other communities in this Study is not applicable, as there is no oil heating or power generation load to displace.

Therefore, no economic feasibility analysis has been performed for Inuvik. The focus of the Study for this community has been to estimate:

1. The demand for natural gas over the analysis period
2. The capital costs associated with converting gas supply from the existing wells to the MGP

Armed with this data, GNWT can determine whether the costs to connect to the MGP are justified based on:

- Security of supply
- Relative commodity costs between the MGP and the current source of gas
- Relative O&M costs between the current gas supply system and the proposed Lateral, CTS and Community Gate Station

16.1.2. Residential & Non-Residential Heating Oil Use per Building

Data on fuel oil use for heating purposes was not available, so consumption levels per building were assumed to mirror the consumption levels in Tulita. To categorize this use into residential and non-residential components, the analysis assumes that consumption of heating oil occurs pro-rata with the consumption of electricity. Based on the results of the 2008 Encor study, it is assumed that there are 1.13 residential accounts per building and 1.00 commercial accounts per building. On this basis, the analysis assumes that the average residential building consumes 1,749 litres of heating oil per year, while the average commercial building consumes 10,523 litres per year. By 2019, it is assumed that there will be 1,459 residential accounts and 478 commercial accounts in Inuvik, increasing to 1,488 and 488 by 2038. Under the Status Quo, it is assumed that 311.8 million litres of fuel oil will be consumed by 2038, while under the natural gas scenario, the equivalent number of litres drops to 297 million litres.

16.1.3. Conversions – Pace & Saturation

Since Inuvik has a natural gas distribution system in place to provide natural gas to its residents for heating and hot water, 90% of customers have already converted from diesel. For purposes of this analysis, it is assumed that the remaining 10% will convert to natural gas before the assumed MGP in-service date of 2019. For power generation, it is assumed that 5% of the community's requirements will continue to be met with diesel generation, in order to provide redundancy in the event of a supply disruption.

16.1.4. Capital Cost for Lateral

The analysis assumes that the community gate station (the second PRS) will be located 28 kilometres from the Mackenzie Valley Pipeline. Based on current consumption requirements, and community growth forecasts, a lateral diameter of 4" will be required based on a lateral operating pressure of 250 psi. Unanticipated growth requirements, including a moderately sized industrial base load, can be satisfied through a combination of excess design capacity and increased operating pressure. Specific capital costs are outlined in Table 1-2, and in Appendix B.

16.1.5. Cost to Convert Power Generation to Natural Gas

Based on the fact that 7.7 MW, or 85% of Inuvik's generating capacity is already gas-fired, an additional $6 million allowance has been included in this Study for the capital cost associated with generation conversion.

16.1.6. O&M and Administrative Costs

Existing O&M and Administrative Costs have been estimated based on the analysis undertaken in the 2010 CGSI Study, in which the two smaller communities of Fort Good Hope and Tulita experienced average costs of $2,300 per account, while the larger community of Fort Simpson experienced an average cost of $1,900 per account. Prorating the difference and projecting it to the account population of Inuvik results in an estimated cost of $1,140 per account.

Incremental O&M costs for the lateral, CTS and CGS are expected to total approximately $332,000 per year.

Working capital (not including fuel inventory) is assumed to be 22% of O&M and Admin costs, which is consistent with the assumptions in the 2008 and 2010 studies.

16.1.7. Plant-in-Service Data

Plant-in-Service data, including installed capital, depreciation, and average annual capitalized expenditures was not available for this Study. Therefore, it has been estimated based on the ratio of each line item to the total generating capacity in the three communities that form the Updated Study Group, prorated for the generating capacity in this community.

16.2. Cost and Demand Summary

Key costs associated with the conversion of the gas supply for Inuvik to the MGP are as follows:

- Custody Transfer Station $ 1.30 million
- Lateral $14.45 million
- Community Gate Station $ .73 million
- Annual Incremental O&M $ .33 million

Demand for natural gas supplied to Inuvik from the MGP is expected to be approximately 498,000 GJ in 2021, increasing to 504,700 GJ in 2038.

17.0 Conclusions & Recommendations

17.1. Summary

The results of the analyses reflected herein suggest that it is economically viable to convert 3 additional communities to natural gas, even without the capital cost exclusions available through the CPCN. The availability of the capital exclusions as currently identified increases the number of communities that can be economically converted to natural gas to 4. A further 4 communities can only be connected to the MGP in an economically viable manner, if some contribution in aid of construction were made toward the capital cost of the lateral. The final 3 communities cannot be converted to natural gas in an economically viable manner even if capital exclusion provisions in the CPCN were modified. Normal Wells and Inuvik have been excluded from this classification, based on the fact that these communities are already fully converted to natural gas.

This information is summarized in the table below:

Community	NPV Savings without Capital Exclusions	NPV of Savings with Capital Exclusions
Fort Good Hope	$6.8 million	$8.2 million
Tulita	$5.4 million	$6.8 million
Fort Simpson	$4.6 million	$6.0 million
Wrigley	($1.2) million	$.2 million
Tuktoyaktuk	($24.3) million	($22.9) million
Deline	($19.2) million	($17.8) million
Fort McPherson	($21.7) million	($20.3) million
Aklavik	($10.1) million	($8.7) million
Tsiigehtchic	($17.5) million	($16.1) million
Jean Marie River	($4.9) million	($3.5) million
Colville Lake	($27.1) million	($25.7) million

It should be noted that the analyses performed herein considered each community on a stand-alone basis. Additional cost savings may be achievable in some instances by using the same lateral for multiple communities, and adjusting the lateral diameter and/or operating pressure as required. This would have the dual benefit of reducing the length of the laterals to some communities, while also enabling two communities to share a single Custody Transfer Station. Possibilities that may merit further consideration include:

1. Serving Aklavik from the Inuvik lateral.
2. Serving Colville Lake from the Fort Good Hope lateral.
3. Serving Deline from the Tulita lateral.
4. Serving Fort McPherson and Tsiigehtchic from the same lateral.

17.2. *Inuvik and Norman Wells*

Inuvik and Normal Wells are unique cases in that each community already has an existing gas supply and community distribution system. Inuvik's gas supply is utilized for both electricity generation and heating/hot water, while Norman Wells purchases electricity from Imperial Oil and utilizes natural gas for heating and hot water. Therefore, for these communities the analysis focuses primarily on the cost of converting the source of gas from the existing wells to the MGP.

17.3. *Recommendations*

17.3.1. Philosophical Direction

A key issue that the GNWT must address is what percentage of the cost savings available through conversion to natural gas will be passed through to residents of the relevant communities, and what portion will be made available to the benefit of other communities. Based on this preliminary analysis, the four communities comprising Groups 1 and 2 will collectively receive net cost savings with a present value of $21.2 million over 20 years. By retaining a portion of these savings for the overall public benefit, the GNWT would be in a position to fund the economic shortfall required to convert Aklavik, or to finance other gas conversion opportunities such as the transportation of CNG or LNG to certain communities.

17.3.2. Fort Good Hope, Tulita, Fort Simpson and Wrigley

For these communities, each of which satisfies economical viability criteria in accordance with the existing CPCN, it is recommended that the GNWT move to the next phase of implementation by commissioning a FEED (Front End Engineering Design) Study in order to design the system and develop more detailed and accurate cost estimates.

17.3.3. Fort McPherson, Deline and Tsiigehtchic

Although none of these communities were deemed to be economically viable given the existing CPCN capital exclusion criteria, it is recommended that a specific analysis be undertaken to determine the technical viability and cost of:

- Connecting Deline to the Tulita lateral
- Service Fort McPherson from a Tsiigehtchic lateral

Although it is not expected that the resulting scenario will lead to economically viable alternatives under the current CPCN parameters, the resulting improvements in economic viability may move these options into consideration for benefit sharing in accordance with Section 17.3.1 above.

For these communities, it is also recommended that alternative gas sources, including the development of CNG or LNG storage and transportation infrastructure, be examined.

17.3.4. Tuktoyaktuk and Aklavik

For these communities, it is recommended that alternative gas sources, including the development of CNG or LNG storage and transportation infrastructure, be examined.

In the event that a decision is made to build a lateral connecting Inuvik to the MGP, it should be determined whether capital and O&M cost savings are available by connecting Aklavik to the Inuvik lateral rather than connecting directly to the MGP. If cost savings are available, the economic viability of supplying gas to Aklavik should be reconsidered.

17.3.5. Jean Marie River and Colville Lake

Given the very small population and gas load available in these communities, it is highly unlikely that an economically viable option for their conversion to natural gas can be developed. Therefore, it is not recommended that the GNWT allocate further resources to exploring the conversion of these communities to natural gas at this time.

17.3.6. Norman Wells and Inuvik

The determination of whether to connect Norman Wells and/or Inuvik to the MGP requires an analysis of a variety of quantitative and qualitative considerations. In order to determine the preferred option for each community, it will be necessary to consider a number of additional factors, including:

- the cost of gas from existing sources relative to the proposed MGP
- security of supply from existing sources relative to the proposed MGP
- the capacity of the existing laterals
- the cost and viability of expanding the capacity of the existing laterals (by increasing pressures or constructing new laterals) where required

The consideration and ultimate quantification of these factors should be the subject of a separate study commissioned or undertaken by GNWT.

17.4. Next Steps

It is recommended that the GNWT undertake the analyses required to:

- Determine whether there are any opportunities to reduce capital costs by having certain communities feed off the same lateral and share a CTS. Options to be considered should, at a minimum, include:
  - Serving Aklavik from the Inuvik lateral.
  - Serving Deline from the Tulita lateral.
  - Serving Fort McPherson and Tsiigehtchic from the same lateral.
- Determine whether it is beneficial to operate laterals at distribution pressures for communities that are in very close proximity to the MGP, in order to eliminate the need for a Community Gate Station.

- Determine whether there are any opportunities to reduce costs by utilizing no-weld flex pipe technology.
- Deterrmine whether CNG or LNG may be technically and economically viable for those communities for which connection to the MGP is not economically viable. Include an examination of both storage and transportation infrastructure.
- Analyze the relative benefits of switching the source of gas for Norman Wells and Inuvik to the MGP versus maintaining the status quo, in order to determine whether a switch in supply is in the best interests of the communities and the NWT as a whole.

APPENDIX A

GLOBAL ASSUMPTIONS

General Assumptions and Factors			
CPI	CPI	1.5%	per year
Gas Inflation	GasCPI	3.68%	per year
Oil Inflation	OilCPI	1.87%	per year
Discount Rate	DiscountPct	10%	per year, nominal
Deprec. Rate - Diesel	DeprRate.Diesel	4.08%	Pct
Deprec. Rate - Ele. Distr.	DeprRate.EleDistr	4.02%	Pct
Deprec. Rate - Ele. Transmission	DeprRate.EleTrans	2.82%	Pct
Deprec. Rate - General	DeprRate.Gen	7.68%	Pct
Deprec. Rate - Natural Gas	DeprRate.Gas	3.00%	Pct
Power Co. WACC	PowerCoWACC	6.48%	
Heat Content	Btu/Cf	1060	Btu/cf
Heat Content	GJPerMMBtu	1.055056	GJ per MMBtu
MVP In Service Year	MVPInServiceYr	2019	November
Base Year	BaseYear	2012	
Litres Per Bbl	LitrePerBbl	159	
GJ Per Mwh	GJPerMwh	3.6	
GJ Per Litre Oil	GJPerLitreOil	0.035	
GJ Per Litre Propane	GJPerLitrePropane	0.02529	
Litres Oil Per Mwh	LitresOilPerMwh	102.86	
CO2 Per GJ Natural Gas	KgCO2PerGJGas	49.90	KG/GJ
CO2 Per GJ Fuel Oil	KgCO2PerGJOil	73.50	KG/GJ
CO2 Per GJ Propane	KgCO2PerGJPropane	61.90	KG/GJ
HoursPerYear	HoursPerYear	8,760	
MVP Community Toll Pct	MVPTownTollPct	50%	
Lateral Cost - 2"		$133,000	diameter-inch per km
Lateral Cost - 3"		$131,000	diameter-inch per km
Lateral Cost - 4"		$129,000	diameter-inch per km
Generation Conversion		$3,400	per kw of capacity
MGP % of Depressurization & Metering Facilities		0%	cost rolled into MGP toll

APPENDIX B

INPUT ASSUMPTIONS – FORT GOOD HOPE

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.12
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,861
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	10,220
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	1,230
Electric Station Service		kwh	SQ.StationKwh	114,000
Losses, % of Electric Sales		%	SQ.KwhLossesPct	5.7%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	54.5%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$3,781.8
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$3,166.4
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$775.1
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$88.4
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$88.4
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$381.3
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$154.3
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$31.2
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$6.8
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$604,934.9
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$127,120.4
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.71
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	N/A
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.55
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$1,330,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$1,059,272
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$3,930,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$467,496
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$127,120
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX C

INPUT ASSUMPTIONS – TULITA

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	3,105
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	6,278
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	1,100
Electric Station Service		kwh	SQ.StationKwh	140,000
Losses, % of Electric Sales		%	SQ.KwhLossesPct	7.4%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	48.2%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$4,170.9
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$2,061.6
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$518.0
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$518.0
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$77.4
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$77.4
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$170.2
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$20.8
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$5.9
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$559,615.2
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$124,883.2
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	350%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.63
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	N/A
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.49
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$1,862,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$980,846
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$3,750,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$426,565
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$124,883
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	175%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX D

INPUT ASSUMPTIONS – FORT SIMPSON

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.14
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,232
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	10,213
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	3,210
Electric Station Service		kwh	SQ.StationKwh	277,828
Losses, % of Electric Sales		%	SQ.KwhLossesPct	4.7%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	62.7%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$5,143.1
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$3,166.1
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$1,091.6
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$1,018.3
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$666.9
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$316.5
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$76.2
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$43.9
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$51.2
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$1,290,194.9
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$278,750.4
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	60%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.57
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	N/A
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.43
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	80%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	80%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	6
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	6
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$10,320,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$2,980,183
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$11,173,256
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$1,035,369
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$278,750
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	30%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX E

INPUT ASSUMPTIONS – NORMAN WELLS

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	1,962
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	9,058
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	2,120
Electric Station Service		kwh	SQ.StationKwh	81,535
Losses, % of Electric Sales		%	SQ.KwhLossesPct	8.5%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	73.9%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$5,984.5
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$3,840.6
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$1,018.4
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$607.7
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$247.3
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$338.5
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$214.8
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$40.9
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$19.0
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$1,046,070.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$233,440.1
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.65
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.50
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$266,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$2,197,592
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$7,208,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$835,180
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$233,440
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX F

INPUT ASSUMPTIONS – TUKTOYAKTUK

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,118
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	6,735
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	2,205
Electric Station Service		kwh	SQ.StationKwh	225,817
Losses, % of Electric Sales		%	SQ.KwhLossesPct	12.1%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	61.3%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$6,224.4
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$3,994.6
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$1,059.2
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$632.1
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$257.2
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$352.0
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$223.4
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$42.6
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$19.8
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$840,500.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$187,565.3
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$1.11
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.86
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$58,950,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$1,696,823
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$7,497,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$677,154
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$187,565
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX G

INPUT ASSUMPTIONS – WRIGLEY

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.00
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	1,872
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	3,417
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	781
Electric Station Service		kwh	SQ.StationKwh	30,981
Losses, % of Electric Sales		%	SQ.KwhLossesPct	8.3%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	44.3%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$2,204.7
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$1,414.9
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$375.2
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$223.9
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$91.1
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$124.7
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$79.1
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$15.1
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$7.0
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$243,760.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$54,397.3
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.54
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.42
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$1,330,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$364,196
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$2,655,400
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$193,363
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$54,397
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX H

INPUT ASSUMPTIONS – FORT MCPHERSON

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,563
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	10,524
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	1,825
Electric Station Service		kwh	SQ.StationKwh	169,995
Losses, % of Electric Sales		%	SQ.KwhLossesPct	3.9%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	58.3%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$5,151.7
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$3,306.2
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$876.7
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$523.2
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$212.9
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$291.4
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$184.9
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$35.2
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$16.4
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$723,840.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$161,531.5
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.99
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.77
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$55,020,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$1,440,230
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$6,205,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$576,591
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$161,532
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX I

INPUT ASSUMPTIONS – AKLAVIK

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	485
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	1,559
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	1,280
Electric Station Service		kwh	SQ.StationKwh	51,389
Losses, % of Electric Sales		%	SQ.KwhLossesPct	11.3%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	54.3%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$3,613.3
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$2,318.9
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$614.9
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$366.9
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$149.3
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$204.4
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$129.7
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$24.7
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$11.5
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$678,300.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$151,368.9
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$1.09
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.84
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$23,940,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$1,336,765
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$4,352,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$520,474
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$151,369
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX J

INPUT ASSUMPTIONS – DELINE

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,406
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	8,257
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	1,140
Electric Station Service		kwh	SQ.StationKwh	59,833
Losses, % of Electric Sales		%	SQ.KwhLossesPct	10.1%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	60.2%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$3,218.1
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$2,065.2
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$547.6
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$326.8
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$133.0
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$182.0
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$115.5
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$22.0
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$10.2
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$571,380.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$127,508.7
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.65
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.50
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$43,230,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$1,105,004
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$3,876,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$445,055
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$127,509
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX K

INPUT ASSUMPTIONS – JEAN MARIE RIVER

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.00
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	1,638
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	2,628
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	230
Electric Station Service		kwh	SQ.StationKwh	38,417
Losses, % of Electric Sales		%	SQ.KwhLossesPct	8.3%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	40.6%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$649.3
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$416.7
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$110.5
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$65.9
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$26.8
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$36.7
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$23.3
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$4.4
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$2.1
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$133,600.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$29,814.1
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.45
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.35
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$6,650,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$165,544
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$782,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$99,655
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$29,814
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX L

INPUT ASSUMPTIONS – TSIIGEHTCHIC

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.00
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	2,254
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	5,500
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	500
Electric Station Service		kwh	SQ.StationKwh	39,972
Losses, % of Electric Sales		%	SQ.KwhLossesPct	7.7%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	47.5%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$1,411.4
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$905.8
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$240.2
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$143.3
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$58.3
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$79.8
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$50.6
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$9.7
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$4.5
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$269,280.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$60,092.3
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.99
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.77
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$31,920,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$409,721
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$1,700,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$204,100
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$60,092
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX M

INPUT ASSUMPTIONS – COLVILLE LAKE

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.00
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	1,713
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	5,855
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	240
Electric Station Service		kwh	SQ.StationKwh	4,957
Losses, % of Electric Sales		%	SQ.KwhLossesPct	13.7%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	36.4%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$677.5
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$434.8
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$115.3
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$68.8
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$28.0
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$38.3
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$24.3
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$4.6
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$2.2
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$154,350.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$34,444.6
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$0.75
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.58
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$45,220,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$202,791
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$816,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$113,785
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$34,445
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX N

INPUT ASSUMPTIONS – INUVIK

Status quo				
Residential Electric Accounts Per Building			SQ.ResAcctsPerBldg	1.13
Non-Residential Accounts Per Building			SQ.ComAcctsPerBldg	1
Residential Oil Use Per Building		Litres/Yr	SQ.ResOilUsePerBldg	1,749
Non-Residential Oil Use Per Building		Litres/Yr	SQ.ComOilUsePerBldg	10,523
Residential Pct On Oil (Others on Propane)		%	SQ.ResOnOilPct	100%
Non-Residential Pct On Oil "		%	SQ.ComOnOilPct	100%
Average Res and Non-Res Load Factor		%	SQ.OilAvgLoadFactor	32.0%
Gas Peak Hour, Pct of Peak Day		%	SQ.OilPkHrPctOfPkDay	4.6%
Electric Generator Capacity		Kw	SQ.GeneratorCapacity	11,260
Electric Station Service		kwh	SQ.StationKwh	1,724,103
Losses, % of Electric Sales		%	SQ.KwhLossesPct	6.2%
Power Co. Load Factor, % of Generation		%	SQ.PowerLoadFactorPct	67.5%
Generation Efficiency On Oil		%	SQ.GenPctEfficiency	38.6%
NTPC Opening Diesel Plant In Service	2019	$000's	SQ.NTPCDieselPIS	$9,853.5
NTPC Accum. Diesel Deprec.	2018	$000's	SQ.NTPCDieselAccumDepr	$6,323.6
NTPC Opening Distribution Plant In Service	2019	$000's	SQ.NTPCDistrPIS	$5,409.1
NTPC Accum. Distribution Deprec.	2018	$000's	SQ.NTPCDistrAccumDepr	$3,227.9
NTPC Opening General Plant In Service	2019	$000's	SQ.NTPCGeneralPIS	$1,313.6
NTPC Accum. General Deprec.	2018	$000's	SQ.NTPCGenAccumDepr	$1,797.7
NTPC AvgAnnualDieselPlantAdds	$2012	$000's	SQ.NTPCDieselPlantAdds	$1,140.6
NTPC AvgAnnualDistributionPlantAdds	$2012	$000's	SQ.NTPCDistrPlantAdds	$217.4
NTPC AvgAnnualGeneralPlantAdds	$2012	$000's	SQ.NTPCGeneralPlantAdds	$100.9
Annual O&M And Admin	$2012	$	SQ.OandMandAdmin	$2,152,320.0
Working Capital before Fuel Inventory	$2012	$	SQ.WCapitalBeforeFuel	$480,309.9
Average Fuel Oil Inventory, Pct of Capacity		%	SQ.AvgFuelOilInventoryPct	75%
Heating Oil Cost - Incremental From Edmonton	$2012	$/litre	SQ.GeneralOilDelCost	$1.09
Propane Cost - Incremental From Edmonton	$2012	$/litre	SQ.GenPropaneDelCost	$0.00
Generation Diesel Fuel Cost "	$2012	$/litre	SQ.NTPCOilDelCost	$0.84
Natural Gas Heating				
No. Res. Conversions at Saturation		%	Gas.ResOnGasPct	100%
No. Com. Conversions at Saturation		%	Gas.ComOnGasPct	100%
No. Years to Saturated Res. Market		Years	Gas.ResSaturationYrs	3
No. Years to Saturated Com. Market		Years	Gas.ComSaturationYrs	3
Generation Efficiency on Natural Gas		%	Gas.GenPctEfficiency	38%
Natural Gas Custody Transfer Station	$2012	$	Gas.GasCTS	$1,301,870
Natural Gas Community Gate Station	$2012	$	Gas.GasCityGateCost	$729,399
Natural Gas Lateral Cost	$2012	$	Gas.LateralCost	$14,448,000
Natural Gas Major Mains Cost	$2012	$	Gas.MainsCost	$7,813,662
Natural Gas Cost Per Service	$2012	$/Bldg	Gas.ServCostPerBldg	$1,400
Generation Conversion Cost	$2012	$	Gas.DieselToGasCost	$38,284,000
Generator Building Cost	$2012	$	Gas.GenBuildingCost	$0
Annual O&M And Admin before new capital	$2012	$	Gas.OandMandAdmin	$2,005,977
Working Capital before Fuel Inventory	$2012	$	Gas.WCapitalBeforeFuel	$480,310
Average Fuel Oil Inventory, Pct of Capacity		%	Gas.AvgFuelOilInventoryPct	38%
Pct Generation Remaining on Oil		%	Gas.GenOnOilPct	5%

APPENDIX O

PRICE AND TOLL FORECASTS

GasCostAtMVPTap

Gas Forecast AECO-C	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
GLJ - Oct 2011 - Cdn$/MMBtu	**4.36**	**4.59**	**5.05**	**5.51**	**5.97**	**6.43**	**6.86**	**7.00**	**7.14**	7.28	7.43	7.58	7.73	7.88
" (C$/GJ)	4.13	4.35	4.79	5.22	5.66	6.09	6.5	6.63	6.77	6.9	7.04	7.18	7.33	7.47
MGP Fuel %					1.0%	1.0%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%	1.6%	1.7%
NGTL Toll C$/GJ	0.25	0.26	0.26	0.27	0.27	0.27	0.28	0.28	0.29	0.29	0.29	0.30	0.30	0.31
MGP Toll - C$/GJ					2.89	2.86	2.79	2.56	2.50	2.38	2.34	2.54	2.55	2.50
Pipeline Tap Price - C$/GJ	#N/A	#N/A	#N/A	#N/A	#N/A	N/A	N/A	5.05	5.21	5.39	5.54	5.58	5.72	5.87

OilPriceAtEdmonton

40 API Oil Price (Edmonton)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
GLJ - Oct 2011 - C$/bbl	**94.39**	**96.94**	**101.02**	**101.02**	**101.02**	**102.41**	**104.47**	**106.58**	**108.73**	110.90	113.12	115.39	117.69	120.05
Cost - C$/Litre	0.59	0.61	0.64	0.64	0.64	0.64	0.66	0.67	0.68	0.70	0.71	0.73	0.74	0.76

GasCostAtMVPTap

Gas Forecast AECO-C	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
GLJ – Oct2011 in Cdn$/MMBtu	8.04	8.20	8.37	8.53	8.70	8.88	9.06	9.24	9.42	9.61	9.80	10.00	10.20
" (C$/GJ)	7.62	7.77	7.93	8.09	8.25	8.41	8.58	8.75	8.93	9.11	9.29	9.48	9.67
MGP Fuel %	1.8%	1.9%	2.0%	2.1%	2.2%	2.3%	2.4%	2.5%	2.6%	2.7%	2.7%	2.7%	2.7%
NGTL Toll C$/GJ	0.31	0.32	0.32	0.33	0.33	0.34	0.34	0.35	0.35	0.36	0.36	0.37	0.37
NGP Toll - C$/GJ	2.43	2.35	2.27	2.18	2.17	0.98	0.96	0.93	0.92	0.93	0.93	0.93	0.93
Pipeline Tap Price - C$/GJ	6.05	6.23	6.42	6.61	6.77	7.51	7.67	7.85	8.02	8.19	8.36	8.54	8.72

OilPriceAtEdmonton

40 API Oil Price (Edmonton)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
GLJ - Oct 2011 - C$/bbl	122.45	124.90	127.39	129.94	132.54	135.19	137.90	140.65	143.47	146.34	149.26	152.25	155.29
Cost - C$/Litre	0.77	0.79	0.80	0.82	0.83	0.85	0.87	0.88	0.90	0.92	0.94	0.96	0.98

APPENDIX P

POPULATION FORECASTS

	Ft Good Hope	Tulita	Ft Simpson	Inuvik	Norman Wells	Tuk	Wrigley	Deline	Ft McPherson	Colville Lake	Aklavik	Jean Marie River	Tsiigehtchic
GNWT Projections													
2011 Population	**567**	**566**	**1,283**	**3,615**	**800**	**929**	**113**	**565**	**791**	**147**	**645**	**76**	**136**
2015 Projection	**591**	**587**	**1,281**	**3,663**	**829**	**912**	**109**	**585**	**783**	**162**	**666**	**73**	**128**
2020 Projection	**585**	**603**	**1,291**	**3,737**	**839**	**891**	**119**	**589**	**779**	**167**	**676**	**70**	**130**
2025 Projection	**573**	**623**	**1,305**	**3,766**	**858**	**866**	**115**	**589**	**775**	**164**	**678**	**67**	**130**
2030 Projection	**559**	**624**	**1,291**	**3,777**	**862**	**829**	**109**	**588**	**758**	**175**	**682**	**65**	**122**

APPENDIX Q

GLOSSARY OF ABBREVIATIONS

AECO	AECO (Alberta Energy Corporation) gas price reference point
AGA	American Gas Association
AHL	Annual heating load
API 40	Light sweet crude (American Petroleum Institute gravity of 40)
CGS	Community Gate Station
CH4	*CH Four* Consulting Inc.
CGSI	Canadian Gas Services International
CSS	Community Sales Station
CTS	Custody Transfer Station (adjacent to the MGP)
GLJ	Gilbert Lautsen Jung Associates
GNWT	Government of the Northwest Territories
HDD	Heating degree day
HDD	Horizontal directional drill (for pipeline river crossing)
IOL	Imperial Oil Limited
ITI	NWT Department of Industry, Tourism and Investment
MGP	Mackenzie Gas Pipeline
MVGCS	Mackenzie Valley Gas Conversion Feasibility Study
NEB	National Energy Board
NGTL	Nova Gas Transmission Limited
NPV	Net present value
NTBS	Northwest Territories Bureau of Statistics
NTPC	Northwest Territories Power Corporation
NTPUB	Northwest Territories Public Utilities Board
NRC	Natural Resources Canada
NUL	Northern Utilities Limited
O&A	Operating and Administration
O&M	Operating and Maintenance
PE	Polyethylene pipe
PRS	Pressure Reduction Station
PSI	Pounds per Square Inch
PUB	Public Utilities Board
PV	Present Value