

ENERGY FOR YUKON: THE NATURAL GAS OPTION

Eagle Plain Case Study

(Energy to Mines (E2M) - Update 2010)

Prepared for the Yukon Department of Energy, Mines and Resources,
Oil & Gas Resources Branch by:

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Eagle Plain Case Study

Executive Summary

Project Description

This study compares the relative costs of various energy supply options for three potential Yukon mine sites with very different energy requirements. The selected mines are: the Casino Mine located west of Pelly Crossing requiring 100 Megawatts (MW); the Selwyn and MacTung Mines on the eastern border of the Territory (33 to 45 MW); and a hypothetical mine located 25 km from the existing Yukon Energy Corporation's (YEC) electrical grid with an electrical demand of five MW. The latter is representative of previous mine developments in Yukon.

Several of the supply options are based on transporting natural gas to a generation station at Stewart Crossing and utilizing the Yukon high voltage electrical transmission system to deliver power to customers. The Whitehorse-Aishihik-Faro (WAF) grid currently has capacity to transmit an additional 40 MW. A significant benefit of this supply option is the provision of energy to YEC to meet its electric generation requirements.

In the course of preparing this study, many scenarios were modelled. The following scenarios are presented in this study to provide a range of possible energy supply options:

- Electrical generation at the mine sites using diesel delivered by truck (the base case for all mines);
- Electrical generation at the Casino mine site using natural gas delivered by pipeline from Eagle Plain;
- Electrical generation at the Casino mine site using natural gas delivered as Liquefied Natural Gas (LNG) by truck from Eagle Plain and LNG from Stewart Crossing (gas piped from Eagle Plain to Stewart Crossing);
- Electrical generation at the Selwyn and MacTung mine sites using natural gas delivered as LNG by truck from Ft. Nelson, BC;
- Electrical generation by YEC at Stewart Crossing using natural gas delivered by pipeline from Eagle Plain. Existing and new transmission lines are then used to transmit the electricity to the three mine projects; and
- Electrical generation by YEC at Whitehorse using natural gas delivered by pipeline from the Alaska Highway Pipeline Project (AHPP) into new or expanded transmission lines from Whitehorse to Casino.

Results

Each energy supply option assumes a mine life of 10 years and a fuel inflation rate of 3% per year (1 % above inflation). The price of diesel reflects 2009 delivered fuel prices for YEC and Yukon Electrical Co. Ltd. (YECL).¹ For the purposes of this study the price of natural gas is

¹ See Page 29 of the E2M 2008 Case Study. YEC/YECL filing to the YUB dated February 2010 estimated the 2009 average rate for the incremental cost of diesel is 27.99 cents/kWh with the exception of Old Crow.

based on an estimate of the cost of development and production at the wellhead. The actual price will be a negotiated price between the gas provider and its customer. The various energy supply scenarios are compared on the basis of the real levelized cost of energy over the mining project life.

In every scenario, using diesel is substantially more expensive than the natural gas options in relative cost terms. This suggests there is substantial opportunity for a supplier of natural gas and a customer to reach a mutually beneficial agreement. The natural gas supplier gains an opportunity to sell what has been a stranded resource. The buyer gains lower energy costs and the potential for long term energy price stability through contracts. Yukon receives direct and indirect benefits from increased economic activity and an additional energy source which will strengthen Yukon's energy supply system. In addition, using natural gas results in 34% less greenhouse gas (GHG) than using diesel.

The study also found that for the size and duration of the potential energy loads envisioned it is less expensive to build a small diameter pipeline than an electrical transmission line. Further, the study found that it was feasible to utilize the WAF grid to deliver energy from central Yukon to Eastern Yukon. This provides more options for servicing mine loads in the east with natural gas from Eagle Plain.

A final observation of the study is that the Alaska Highway Pipeline Project can materially assist in the commercialization of Eagle Plain gas to serve local markets. The AHPP could provide impetus to construct a pipeline connecting MacKenzie Delta natural gas to the AHPP at Whitehorse. This large diameter pipeline would transect Eagle Plain basin which would significantly lower the cost of service for Eagle Plain gas. The Eagle Plain basin could provide an additional 300 or 400 million cubic feet per day (MMscfd)² to AHPP through this connecting pipeline.

² Figure 12, page 30, Fekete Engineering, North Yukon Conceptual Oil and Gas Development Scenario and Local Benefits Assessment, November 2005.

Background: E2M Study 2008

In 2008 the Oil and Gas Resources branch (OGR) released the Energy to Mines (E2M) Study.³ The report was a preliminary investigation of the “potential opportunity to utilize natural gas in electric power generation in Yukon and to test the economic viability, risks and obstacles of the concept. To do this, a proposed Yukon pipeline grid was designed to ship natural gas from Eagle Plain to various mine sites and electrical generation sites in Yukon.” The study found that natural gas electrical generation, using gas delivered to the mine site by pipeline from Eagle Plain, compared favourably with extending electrical transmission lines from the YEC electric grid. As well, the study found that both natural gas generation and electrical transmission to mine sites were much more economic than diesel-generated power at the mine sites.

E2M concluded that there was merit in undertaking a more in-depth natural gas/electric generation study. The result of the more in-depth analysis is this paper - *Eagle Plain Case Study*. As indicated by the title it is one component of the project *Energy for Yukon: the Natural Gas Option*. It updates the numbers in the original study and assesses other scenarios and delivery options for utilizing natural gas as an energy source. In both reports the cost estimates, while stated in absolute terms, are more usefully viewed in relative terms.

This study was completed by Wolf Island Engineering with the cooperation, analysis and input from Leading Edge Projects Inc., Confer Consulting Ltd. and Ellwood Energy Projects Ltd.

Scope and Methodology

The scope of this study is to determine and compare the costs of the various options for generating electricity with natural gas from Eagle Plain for various Yukon mine sites as well as for transmission on the YEC electric grid. The proposed mines used in the study are the Casino Mine located west of Pelly Crossing, the Selwyn and MacTung mines located on the eastern Yukon border and a hypothetical mine located 160 km from Stewart Crossing and 25 km from the existing YEC electrical grid with a demand of five MW and a life of seven years. The latter is representative of several previous Yukon mines. Location of these mines can be seen on Figure 1 – Advanced Exploration Projects in Yukon.

The various energy supply options compared in this study are as follows:

- Electrical generation at the mine sites using diesel delivered by truck (the base case for all mines);
- Electrical generation at the Casino mine site using natural gas delivered by pipeline from Eagle Plain;
- Electrical generation at the Casino mine site using natural gas delivered as LNG by truck from Eagle Plain or from Stewart Crossing with gas piped to Stewart Crossing;
- Electrical generation at the Selwyn and MacTung mine sites using natural gas delivered as LNG by truck from Ft. Nelson, BC;

³ Wolf Island Engineering, Energy to Mines Study, January 10, 2008, revised December 1, 2009.

- Electrical generation at Stewart Crossing using natural gas delivered by pipeline from Eagle Plain with a new transmission line (Casino), or into the existing grid with new transmission lines (Selwyn, MacTung, or hypothetical mine); and
- Electrical generation at Whitehorse using natural gas delivered by pipeline from the AHPP into new or expanded transmission lines from Whitehorse to Casino.

The mining locations and the YEC electrical transmission grid are also shown on Figure 1 – Electrical Infrastructure, Mining and Oil & Gas in Yukon.

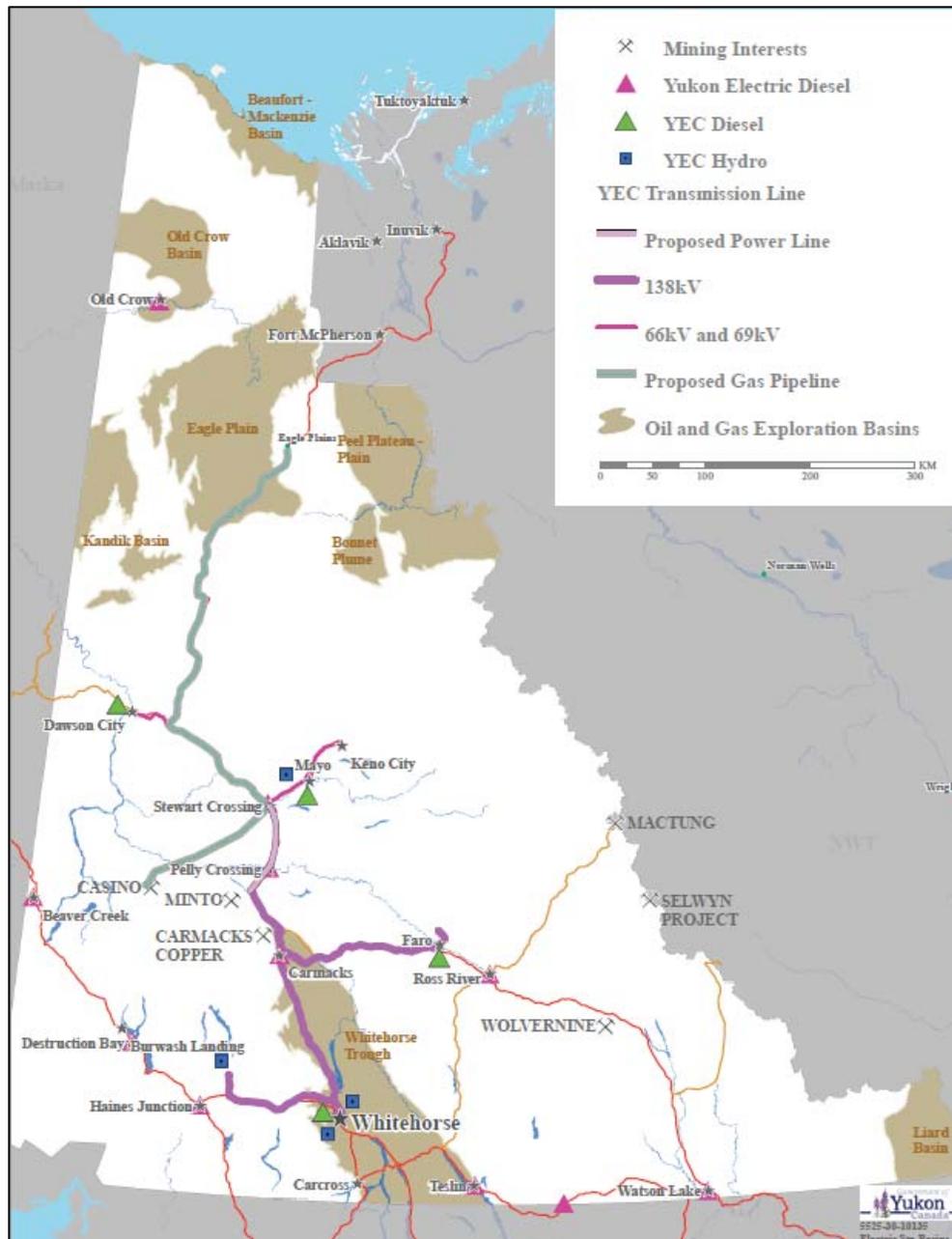


Figure 1 – Yukon’s Transmission System and Proposed Mines

Conceptual Yukon Pipeline

For the purposes of this study, a Yukon pipeline was conceptually designed in order to deliver natural gas to central Yukon. For more detail, see Figure 2 – Conceptual Yukon Pipeline Grid, on the next page.

The “Yukon Mainline” would take gas from the Eagle Plain basin and follow the Dempster and Klondike highways to Stewart Crossing to take advantage of the 138 KV transmission grid being extended from Pelly Crossing to Stewart Crossing. Gas delivered to Stewart Crossing would generate electricity to be delivered to customers through the existing electric grid and possibly new transmission lines depending on the required load. As well, the Stewart Crossing Compressor Station could deliver natural gas into a Casino Lateral. This lateral would be constructed cross-country delivering natural gas to the Casino mine site where it would be used to generate electricity for the mine operations.

The Stewart Crossing delivery point could also be used to produce LNG for delivery by truck to smaller and/or remote mines in central and southern Yukon.

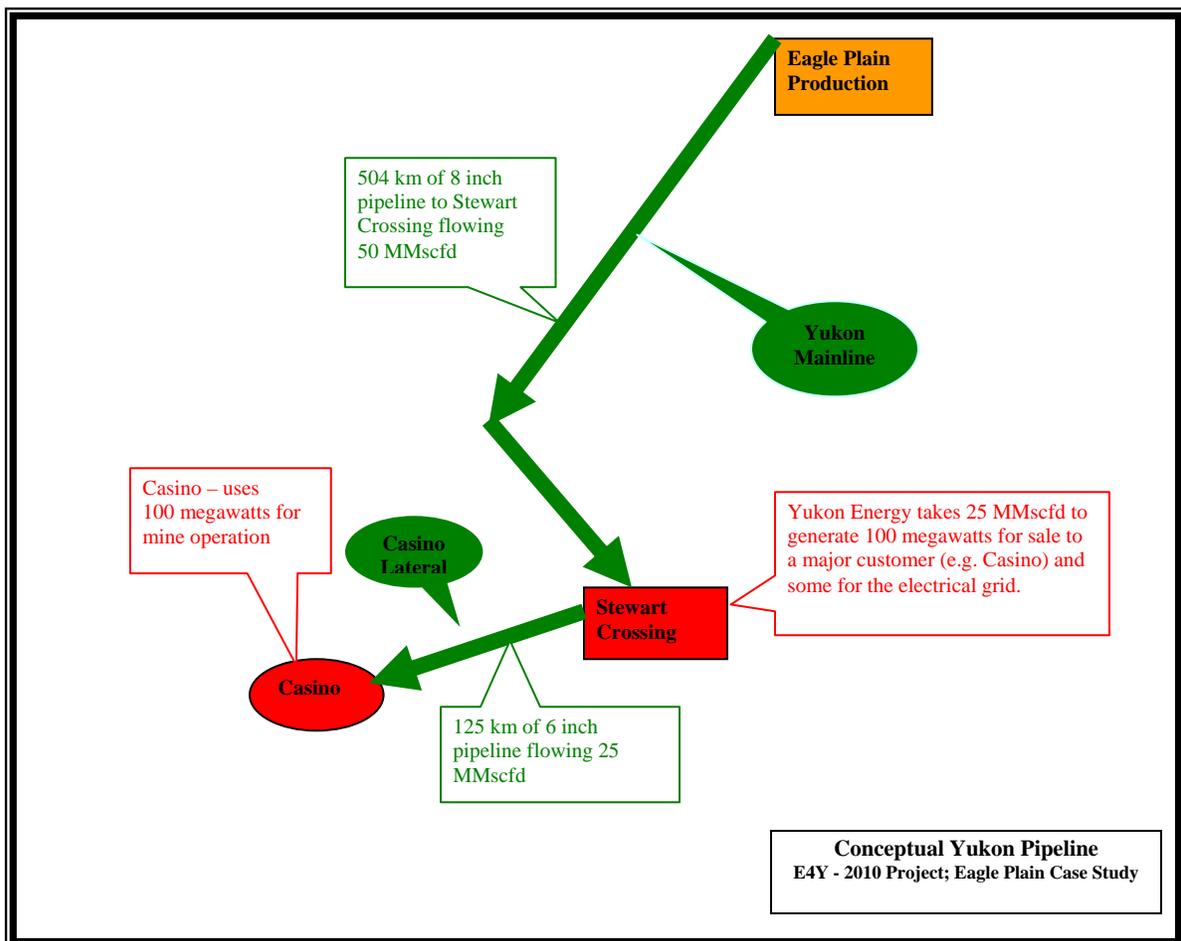


Figure 2 – Conceptual Yukon Pipeline

Yukon's Mining and Electrical Generation Sectors

As can be seen from Graph 1⁴, Yukon's electrical demand from mines alone is forecast to be in the order of 200 megawatts (MW) by 2016. Of the 200 MW approximately 20 MW is within the service range of YEC's transmission grid. The current installed capacity of YEC is 139 MW of which 75 MW is hydro generated.⁵ While this is sufficient to meet current demand, anticipated new industrial load combined with base load growth will require additional generation capacity as soon as 2012 to avoid relying on diesel generation. The YEC planned hydro expansion (Mayo B) will assist in meeting this gap. However, if all the new industrial loads within the service range of YEC proceed as proposed, YEC will be short of hydro generated energy in the near future. Alternatively, if none of the proposed new mines proceed YEC will have sufficient energy to meet its future obligations with its existing hydro generated energy.

As a regulated utility, YEC must prudently balance planning and assessing new investments for future load growth while at the same time not over building new generation. As an isolated electric grid YEC does not have the option of selling surplus energy into other markets and buying deficits from adjacent generators. Getting the balance of load and generation right is even more problematic if trying to balance the differing characteristics of hydro and mining projects.

Mining projects respond to the commodities market and for this reason frequently need to be developed relatively quickly, paid for quickly and ramped up and slowed down quickly over their lives in response to mineral prices.

Hydro projects, high voltage transmission lines and pipelines are capital intensive, require long lead times to plan and build and have fixed costs with a long payback period. For this reason they typically require one or more credit worthy customers who are willing to sign long-term contracts before financing can be secured.

Electrical generation projects using either turbine or reciprocating engines, with diesel or natural gas as the fuel, typically have more flexibility. This is also the case for LNG manufacturing and delivery facilities. They can often be staged to better match the build up of power needs over time, thus requiring lower initial capital. They can often be modularized in truckable units and hence can be moved to new locations if required.

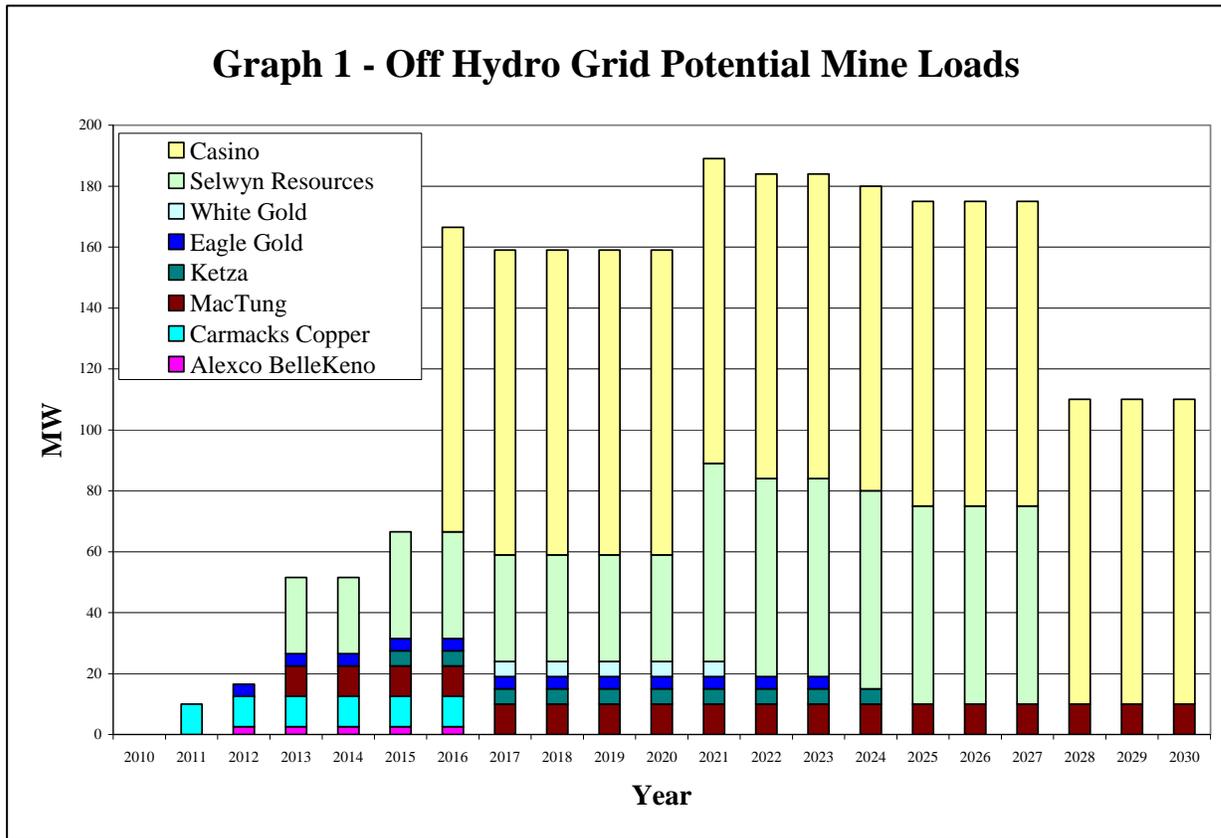
For the purpose of this study, proposed mines off the electric transmission grid were selected for assessing natural gas as an alternative energy source. The Casino mine is somewhat atypical of previous mining projects in Yukon in that it will have a relatively high power requirement and is expected to be in operation much longer than most previous projects.

Therefore, Casino was chosen as a base market for natural gas electrical generation given its proposed energy requirement of 100 MW of demand over a 30 year mine life. The Selwyn and MacTung mines near the Yukon/Northwest Territories border were selected based on their advanced stage of exploration, significant energy requirements (33 to 45 MW) and proximity to each other. These mines represent an intermediate group in terms of power requirements and longevity.

⁴ Department of Economic Development, Yukon Government, May, 2010.

⁵ YEC Presentation, "Yukon's Electrical Needs to 2019", June 2, 2010

A smaller 5 MW hypothetical mine located 160 km from Stewart Crossing and 25 km from the existing electrical grid was also assessed as representative of previous mining operations in Yukon.



This study does not address other cost factors which the mine developer must consider when evaluating the overall economics of a potential mine development such as the cost of road access to the mine site. The focus of this study is meeting the energy requirements of the mine.

Assumptions

The economic and cost estimating assumptions underlying this study are detailed in Attachment 4. Two key assumptions are the price of natural gas and the calculation of GHG output.

By not being connected to the North American natural gas grid there is no Yukon commodity market for natural gas. Setting a price for the Eagle Plain natural gas will be a negotiation between the supplier and the buyer. If there is more than one buyer and only one supplier, it may be difficult to negotiate a fair and reasonable price. Under this scenario the Yukon Utilities Board would likely have a role in establishing a fair and reasonable price. For the purpose of this study, the price of gas is based on an estimated cost of production and the initial gas price was increased relative to inflation only and without regard to the North American market since there is not necessarily going to be a connection between the two markets.

Only GHG emissions related to the operating fuel of the generating plants were calculated for this paper. Not included were the GHG emissions from the manufacturing of the equipment, the construction and operation of the facilities and GHG emissions from trucking diesel fuel or LNG.

Analysis

Natural Gas Costs

In order to determine the economic attractiveness of utilizing Yukon's natural gas resources within Yukon, it is necessary to develop the unit costs of providing natural gas to the various mines listed in the previous section. To do this, the cost estimates were developed in four parts on a relative basis. These are first order cost estimations and are intended for cost comparisons only.

First, estimates were developed for the production of natural gas at the Eagle Plain field. These are called Field Production Costs and they are detailed in Attachment #1, "Estimates of Costs for the Conceptual Yukon Pipeline."

Second, the costs of delivering the natural gas to the various mine and electrical sites by pipeline are determined. These are called Mainline or Lateral costs and they are also detailed in Attachment #1.

Third, the cost of generating the electricity from natural gas at various sites is also estimated. This includes electricity generation at Stewart Crossing for the Selwyn and MacTung mines at the Yukon/Northwest Territories border and using existing transmission lines plus a line extension from Faro to these mines to deliver this electricity.

Fourth, delivering natural gas in the form of LNG by truck to the mine sites is also assessed and these costs involve liquefaction at Eagle Plain, or Stewart Crossing, or Ft. Nelson; trucking to the mine sites; and re-gasification at the mine site. They are detailed in Attachment #5.

Fifth, taking natural gas from AHPP and delivering it to the YEC grid at Whitehorse for electrical generation and transmission in a new or upgraded transmission line up to Casino is also analyzed.

The total cost of generating electricity with natural gas at the mine sites is shown in Attachment #2.

Pipeline Costs

As can be seen in Figure 2 - Conceptual Yukon Pipeline, a total of 629 km of pipelines are needed to transport natural gas from Eagle Plain to Stewart Crossing and then from Stewart Crossing to the Casino Mine Site. The mainline from Eagle Plain to Stewart Crossing would be built alongside existing highway corridors and the lateral to the Casino mine would be constructed cross-country.

In 2007, Nova Gas Transmission applied to the Alberta Energy and Utilities Board to construct 300 kms of 42-inch pipeline across the northern part of the province. Nova estimated the cost of the pipeline with compression to be \$983 million (2007 CDN). This equates to \$78,000 CDN per diameter-inch/km.

For the purposes of this study, because of the proposed smaller diameter pipe to be constructed and because about two-thirds of the pipeline would be constructed alongside existing highways, an estimate of \$60,000 per diameter-inch/km is used for pipe being constructed along an existing highway and \$80,000 per diameter-inch/km for pipe being constructed cross-country to Casino.

Using the above estimates, the capital costs, in 2009 dollars, for the Mainline and Casino Lateral are as follows:

- Yukon Mainline \$242 million CDN
- Casino Lateral \$60 million CDN

The details of these costs are shown in Attachment #1, Estimates of Costs for the Conceptual Yukon Pipeline.

The pipeline and lateral toll estimates have been developed by Confer Consulting and are also included in Attachment #1.

It should be noted that an O&M cost of 1.5% of initial capital cost was chosen for annual operating costs which is conservatively high.

On-Site Electrical Generation Costs

Converting the natural gas to electricity at the mine sites and the YEC grid was assumed to utilize LM6000 General Electric single-cycle gas turbines (or equivalent) and associated electrical generation equipment at each site. Two of these units will generate about 85 MW of electricity. The General Electric website indicates that the efficiency of these units is about 40%. Therefore, the 100 MW of electricity needed at Casino requires about 25 MMscfd of natural gas delivered to the mine site. For the purposes of this study, a capacity utilization of 90% is used.

It should be noted that another major component of mine operating costs is the generation of space heating. An added benefit of on-site turbine electrical generation is the use of the waste heat from the turbine to heat the buildings and facilities. Although this study restricted itself to single cycle turbines, the use of combined heat and power units could further reduce operating costs.

Diesel Power Generation Costs

For this analysis new low-RPM baseload diesel generators were assumed to be used. The installed cost for diesel generators is about \$1.2 million per MW, and the operating cost is assumed to be \$0.02 per kWh, a figure used by YEC. Fuel efficiency is assumed to be 4.00 kWh per litre of diesel fuel and the life expectancy is about 20 years.

Late 2009 delivered fuel prices for YEC and The Yukon Electrical Co. Ltd. were averaging about \$0.85 per litre (equivalent to \$0.2125 per kWh) in road accessible locations, and this figure was adopted as the baseline for this study.

Electrical Transmission Line Costs

Transmission lines of two different voltages occur in this study under different circumstances. The annual O&M costs for transmission lines are assumed to be 0.5% of the original capital

costs. The capital costs for the transmission lines include any necessary substations. The installed costs for transmission lines were developed as outlined below. Depending on prevailing economic conditions at the time of construction, the installed costs may be conservatively high.

1. 25 kilovolt (kV) lines are assumed to cost \$300,000 per km. This is based on the Minto spur line having cost about \$10 million for about 29 km (about \$345,000 per km) with some downward rounding to allow for the fact that the Minto spur line involved a barge crossing of the Yukon River.
2. 138 kV lines to big mines are assumed to cost \$600,000 per km on the basis that a high capacity line would cost more than the Carmacks to Pelly Crossing line (about \$300,000 per km) and the projected cost of the Pelly Crossing to Stewart Crossing line (including substations) of about \$533,000 per km.

LNG Costs

LNG is a potential alternative to pipelines as a means of delivering natural gas to electrical generation facilities. LNG can be stored and transported by truck in double walled “thermos” containers or vessels. In recent years there have been a number of advances in LNG technology to the point where there are now several firms designing and constructing “off the shelf,” modularized LNG plants capable of processing 1 – 20 MMscfd of natural gas. Modularized, skid mounted facilities can be relocated as needed at moderate cost and, since they could be used at more than one site, accelerated depreciation may be avoided compared to assets such as pipelines, transmission lines, dams, or other fixed assets.

In this study various scenarios for the location of the LNG plant are considered. One location is Eagle Plain with LNG trucked to the Casino mine’s re-gasified electrical generation facilities. An alternative location is Stewart Crossing after the gas is transported by pipeline from Eagle Plain. Upon liquefaction at Stewart Crossing, the LNG would be transported to Casino or a 5MW mine. For the Selwyn and MacTung mines along the Yukon/NWT border, natural gas would be liquefied at Ft. Nelson with subsequent truck transport to the mines. Costs have been developed for LNG facilities capable of feeding 10, 20, 40 and 80 MW generation plants.

For power requirements above 100 MW it is assumed that a pipeline would be constructed from Eagle Plain to Stewart Crossing and the LNG plant would be relocated to the end of the pipeline where its output would be trucked directly to generation facilities located at remote mine sites elsewhere in Yukon.

Costs are based on budgetary estimates from suppliers for labour and equipment requirements based on experience. The costs range from around \$10 million for 2.5 MMscfd of delivered LNG to about \$50 million for 20 MMscfd of LNG. These costs include the LNG plant, five days of storage at the LNG plant location, a truck loading station, a truck off loading station, five days of storage at the receiving terminal and a vaporizer or re-gasifier.

LNG appears to be uneconomical above a generation requirement of 200MW because of logistical and cost issues. For example, 200MW of generation capacity requires about 50 MMscfd of gas, which, in turn, requires the equivalent of about 535,000 Imperial gallons per day or about 45 truck loads. If this was sourced at Eagle Plain it would require about 90 trucks on the road at any given time with a total fleet size of about 95 or 100 trucks with about 135

drivers, which means a substantial permanent camp at Eagle Plain and associated facilities. This would not be practical and certainly uneconomical.

Therefore the study limited the LNG options to smaller scale developments such as 25 MMscfd (100 MW equivalent) for the Casino mine (produced at either Eagle Plain or Stewart Crossing) and 1.25 MMscfd (five MW load) at Stewart Crossing for a small mine. This initial load for the small mine would be about 1 or 2 trucks per day which is feasible and would have a minimum impact on road maintenance costs.

Natural Gas Costs from the AHPP

In order to estimate the cost of providing natural gas at a YEC Whitehorse generating station and then upgrading and installing sufficient transmission facilities between Whitehorse and Casino, four costs had to be determined. They are as follows:

- Cost of delivering North Slope natural gas to the Whitehorse area via AHPP;
- Cost of depressurizing and metering the natural gas at Whitehorse;
- Cost of electrical generation at Whitehorse; and
- Cost of electrical transmission (and line losses) to Casino.

The costs of delivering natural gas from the North Slope were determined by adding the tolls required to deliver the gas to Whitehorse to the net back prices of the North Slope gas shippers.⁶ The costs of delivering natural gas to a YEC Whitehorse electrical generating station included depressurization, metering and a 10 km lateral⁷ and are shown in Attachment #6.

A new transmission line from Whitehorse to Stewart Crossing would be required because the present line is restricted to 50 MW when an additional 100 MW is required for the purpose of this comparison. These costs and the cost for a new transmission line from Stewart Crossing are included in Attachment #2.

Greenhouse Gas Emissions

Environment Canada data for the CO₂, CH₄ and N₂O emitted from the combustion of natural gas and diesel fuel were used to calculate the overall GHG emissions. The presently accepted United Nations global warming potential for CH₄ and N₂O expressed as CO₂ equivalent were used to calculate the overall GHG emissions in CO₂ equivalents (CO₂ eq). The factors are 21 for CH₄ and 310 for N₂O. For the study a figure of 1890g CO₂ per m³ of gas is adopted.

Results

It should be noted that these estimates correspond to the American Association of Cost Engineers (AACE) Class 5 i.e. they are useful for screening purposes only. They show that natural gas has a cost advantage over diesel but additional work would need to be done to get a more reliable picture of the differences between the various natural gas options.

⁶ TransCanada PipeLines AGIA application, section 2.10, Project Viability toll and net backs - November 30, 2007

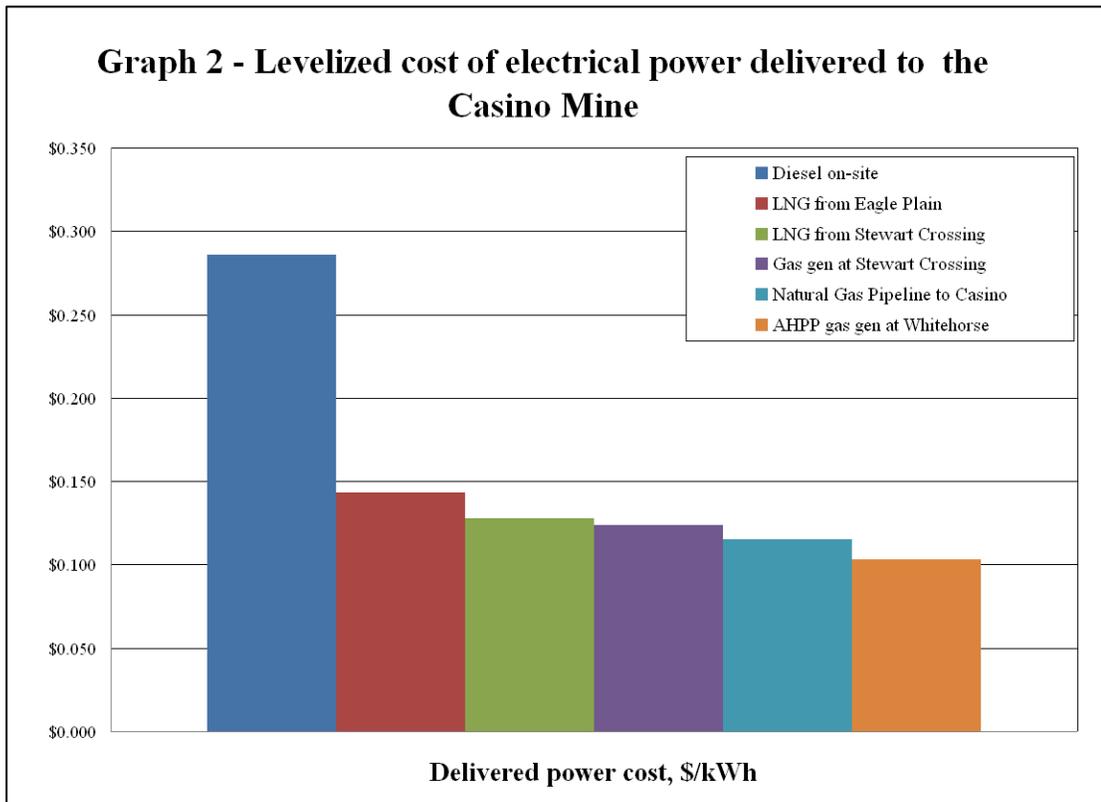
⁷ Estimated Costs for Providing Natural Gas to Yukon Communities, Wolf Island Engineering - revised August 10, 2009

Costs were compared for a mine’s project life of 10 years and 25 years. The natural gas and diesel generation cases considered are reasonably well matched for a life of either 10 or 25 years. Only the 10 year results are presented in this report as it is more in line with the timeframe for a mining project.

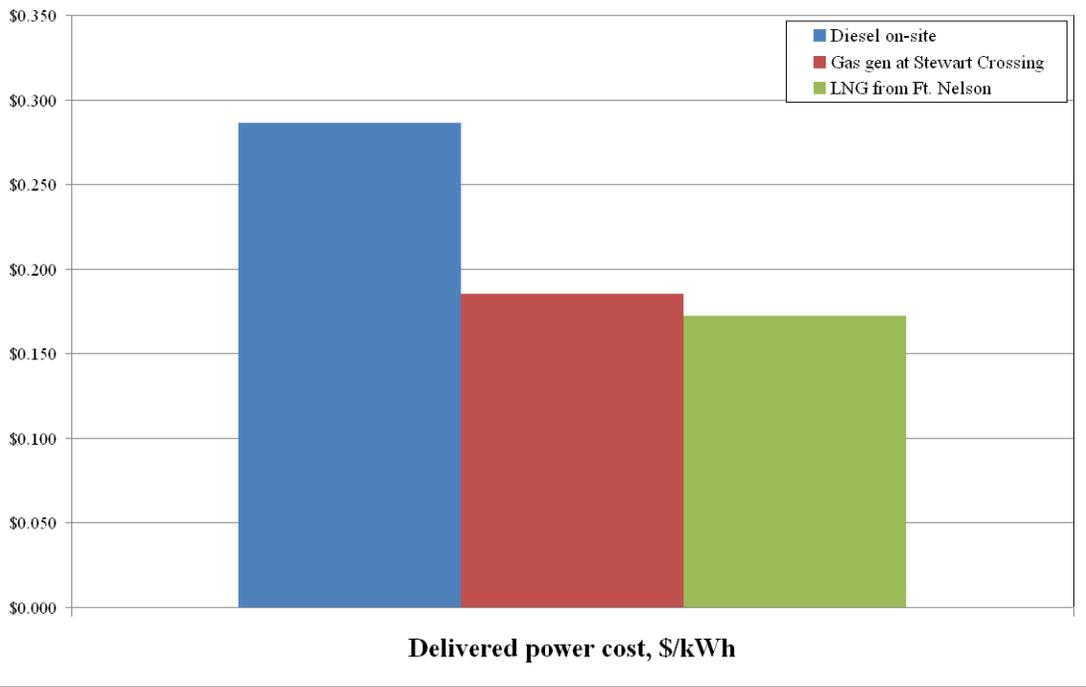
All of the analyses are compared on the basis of the real levelized cost of energy over the mine’s project life and with a fuel inflation rate of 3% per year (1 % above inflation). The real levelized cost of energy is a measure of the cost of energy over the life of a project calculated with the real increasing cost of energy supply and with an appropriate discount rate (based on the cost of capital and inflation) applied to future years’ costs and energy benefits.

The Casino Lateral pipeline costs have been calculated on a cost per kWh basis (kWh of electrical load at the mine site) similar to that for electrical transmission lines. They are treated as separate projects the costs of which are added to the electrical costs rather than to the gas costs. Electrical transmission costs are also treated in this manner and electrical line losses are added separately.

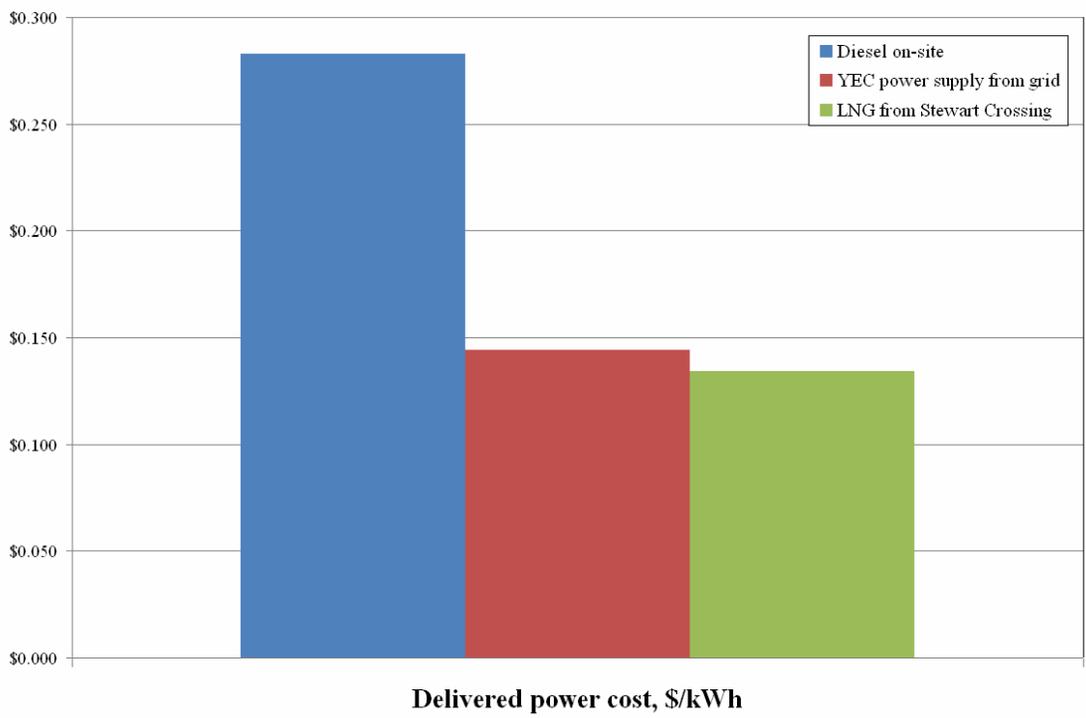
The full cost comparison results can be found in Attachment #2, Summary of Different Power Supply Costs to Mines. The following Graphs #2, #3, and #4 highlight the key comparisons for further discussion.



Graph 3 - Levelized cost of electrical power to the Selwyn and MacTung mines



Graph 4 - Levelized cost of electrical power delivered to 5MW mine



Casino Mine

For Casino, using diesel to generate electricity costs about \$0.286 per kWh and is between two to three times as expensive as the various options using natural gas or LNG. Piping natural gas to Casino and generating it there would cost \$0.115 per kWh and is marginally better than the cost of \$0.124 per kWh for generating the electricity at Stewart Crossing and transmitting it on electric transmission lines. The LNG options are slightly more expensive again at \$0.128 per kWh with LNG produced at Stewart Crossing and \$0.143 per kWh with LNG produced at Eagle Plain. Again, this analysis does not take into account the potential benefit of the waste heat from gas or diesel generation at the mine site.

Supplying Casino with electricity generated from AHPP gas by YEC at Whitehorse over a 25 year span has a slightly lower cost at \$0.103 per kWh compared to electricity generated from Eagle Plain gas at Stewart Crossing (\$0.124 per kWh over a 10 year span). Since natural gas pipelines are less costly to build than electrical transmission lines, piping the gas to Casino should be somewhat cheaper than the \$0.103 per kWh for gas generated electricity at Whitehorse and then transmitted to Casino.

Selwyn and MacTung Mines

Supplying the Selwyn and MacTung mines with trucked LNG produced at Ft. Nelson produces slightly lower costs at \$0.172 per kWh than electricity generated at Stewart Crossing and delivered by a combination of existing and new transmission lines, which costs \$0.185 per kWh. However, diesel generation at \$0.286 per kWh is still the most expensive by a significant margin.

5 MW Mine

The same comparison is made for a smaller hypothetical mine with a seven year lifespan located 160 km from Stewart Crossing and 25 km from the existing YEC grid serviced with a 25 kV line. As expected, the shorter distance and lower voltage of the transmission line improves the economics for electrical transmission as compared to on-site diesel generation. In this case, the unit costs for electrical transmission are \$0.144 per kWh or about one half that of diesel on site generation at \$0.283 per kWh. However, trucked LNG produced at Stewart Crossing has an even lower cost at \$0.134 per kWh.

GHG Emissions

A detailed analysis of GHG emissions for the various energy supply options is presented in Attachment #3, Summary of Different Project/Supply Option Greenhouse Gas Emissions During Operation.

The next most favourable option for GHG production, after grid-supplied hydro power, was the use of natural gas as compared to diesel generation.

AHPP

If an Alaska Highway pipeline were built, the Eagle Plain basin could provide 300 or 400 MMscfd⁸ through a southern “Dempster Lateral” which would significantly lower the Yukon gas pipeline cost of service because of economies of scale.

⁸ North Yukon Conceptual Oil and Gas Development Scenario and Local Benefits Assessment, November 2005 - Figure 12, page 30.

Attachment #1⁹

Estimates of Costs for the Conceptual Yukon Pipeline

Estimates of Delivered Costs of Natural Gas:			
Eagle Plain to Central Yukon (2006\$)			
Gas Field Costs			
Raw Gas Cost, including royalty			2.50
Field Capital Costs			
- Marketable Production	MMcfd	12.0	
- Average Capital Invested (2003\$)	\$000s	36,900	
- Capital Recovery Factor	See Panel A	20.44%	
Annual Capital Recovery Cost (2003\$)	\$000s/y	7,544	
Annual Marketable Production	MMcfd	4,380.0	
Annual Unit Cost	\$/Mcf	1.72	
Escalation Rate	per year	2%	
Escalation Factor to 2006\$	Escalate at	1.0612	
Annual Unit Cost for Capital Recovery	2006\$/Mcf	1.83	1.83
Field Operating Costs (excluding royalty)	\$/Mcf	0.90	0.90
Unit Field Costs @ 100% Load Factor	\$/Mcf		5.23
Marketable Production at Eagle Plain	MMcfd		50.0
Annual Field Costs	\$000s/y		95,406

Total Delivered Cost of Gas		
<u>Location</u>		<u>Total Cost</u>
Stewart Crossing	\$/Mcf	7.05
Casino	\$/Mcf	7.96

⁹ Confer Consulting Ltd., Estimates of Delivered Costs of Natural Gas – Eagle Plain to Central Yukon, February 26, 2010 – revised July 29, 2010.

Pipeline Costs @ 100% Load Factor			
		Pipeline	
		Yukon	Casino
		<u>Mainline</u>	<u>Lateral</u>
Flow	MMcfd	50.0	25.0
Distance	km	504	125
Diameter	inches	8.0	6.0
Unit Cost - On Highway	\$/dia-inch-km	60,000	80,000
Capital Cost	\$000s	241,920	60,000
Cost of Service Factor	See Panel B	13.77%	13.77%
Annual Cost of Service	\$000s/y	33,301	8,259
- Toll at 100% Load Factor	\$/Mcf	1.82	0.91
Eagle Plain to Stewart Crossing	\$/Mcf	1.82	
Eagle Plain to Casino	\$/Mcf		2.73

Panel A			
		Capital Recovery Factor for:	
		Field Facilities	LM6000
Depreciation		5.00%	5.00%
Debt			
- Capital Structure		40%	60%
- Debt Cost		6%	6%
- Debt Cost (weighted)		2.40%	3.60%
Equity			
- Capital Structure		60%	40%
- ROE (After Tax)		15%	10%
- ROE (After Tax) (weighted)		9.00%	4.00%
Income Tax	31%	4.04%	1.80%
- ROE (Before Tax)		13.04%	5.80%
Total Capital Recovery Factor		20.44%	14.40%

Panel B		
Pipeline Cost of Service Factor		
Depreciation	(40 year life)	2.50%
Debt		
- Capital Structure	70%	
- Debt Cost	6%	
- Debt Cost (weighted)	4.20%	4.20%
Equity		
- Capital Structure	30%	
- ROE (After Tax)	11%	
- ROE (After Tax) (weighted)	3.15%	
Income Tax	31%	1.42%
- ROE (Before Tax)		4.57%
Capital Recovery Factor		11.27%
Property Tax		1.00%
O&M		1.50%
Total Pipeline Cost of Service Factor		13.77%

Attachment #2¹⁰

Summary of Power Supply Costs to Mines

Project / Supply option	Initial fuel cost \$/l or \$/Mcf	Real levelized cost of energy						
		Power generation cost \$/kWh	Pipeline cost \$/kWh	LNG plant cost \$/kWh	Trucking cost \$/kWh	Electric Transmission cost \$/kWh	Electric Transmission losses 10%, \$/kWh	Delivered power cost, \$/kWh
Casino								
Diesel on-site	\$0.85	\$0.286						\$0.286
Natural gas from SC hub	\$7.05	\$0.103	\$0.012					\$0.115
LNG from SC hub	\$7.05	\$0.103		\$0.013	\$0.012			\$0.128
LNG from Eagle Plains	\$5.23	\$0.086		\$0.013	\$0.044			\$0.143
YEC gas gen at Stewart	\$7.05	\$0.101				\$0.012	\$0.011	\$0.124
AHPP YEC gas gen at Whse	\$3.61	\$0.074	\$0.002			\$0.019	\$0.008	\$0.103
Selwyn/MacTung (Passes)								
Diesel on-site	\$0.85	\$0.286						\$0.286
LNG from Ft. Nelson	\$5.08	\$0.084		\$0.015	\$0.073			\$0.172
YEC gas gen at Stewart	\$7.05	\$0.101				\$0.073	\$0.011	\$0.185
5MW mine (line from 138kV)								
Diesel on-site	\$0.85	\$0.283						\$0.283
LNG from SC hub	\$7.05	\$0.101		\$0.024	\$0.009			\$0.134
Mine 25km from present grid		\$0.100				\$0.033	\$0.011	\$0.144
Notes	1	Project lives compared are for 10 years except Casino AHPP gas generation which is 25 years and the 5 MW mine which is 7 years						
	2	Fuel inflation rate is assumed to be 3% and general inflation 2%						

¹⁰ Leading Edge Projects Inc., Summary of Different Power Supply Costs to Mines with Varying Lives - May 14, 2010

Attachment #3¹¹

Summary of Project/Supply Option Greenhouse Gas Emissions From Operations

Project / Supply option	GHG emissions per year		
	Total energy generated, GWh	GHG emissions, tonnes per GWh	Total GHG emissions tonnes
Casino			
Diesel on-site	876	697.5	611,010
Natural gas from SC hub	876	462.6	405,238
LNG from SC hub	876	462.6	405,238
LNG from Eagle Plains	876	462.6	405,238
YEC gas gen at Stewart	973.3	462.6	450,249
AHPP YEC gas gen at Whse	973.3	462.6	450,249
Selwyn/MacTung (Passes)			
Diesel on-site	438	697.5	305,505
LNG from Ft. Nelson	438	462.6	202,619
YEC gas gen at Stewart	486.7	462.6	225,147
5MW mine (line from 138kV)			
Diesel on-site	43.8	697.5	30,551
LNG from SC hub			
Mine 25km from present grid	48.7	0	0

¹¹ Leading Edge Projects Inc., Summary of Different Power Supply Costs to Mines with Varying Lives - May 14, 2010

Attachment #4

Background Information and Assumptions for Analyses¹²

Oil cost projections

1. One information source is the US Energy Information Agency's *Annual Energy Outlook 2010* presentation dated December 14, 2009 (delivered and published on website in early January 2010). Its forecasted increase in price for low sulphur light crude oil in constant dollars for the period 2010 to 2035 is 1.1% per year, and for imported crude oil is 1.0% per year (and in nominal dollars 3.0% per year). The forecasted increase in price for distillate fuel oil is 0.7% per year in constant dollars and 2.7% in nominal dollars. The implied general inflation rate (equivalent to consumer price index or CPI) is about 2.0% per year.
2. The other source is a presentation made by TransCanada PipeLines to Alaskan officials. It quoted information from the US DOE for light sweet imported crude oil prices which suggests that the real cost in real 2009 US\$ per barrel will increase to \$126 in 2030 from about \$75 or an average of about 2.6% per year. Most of this increase is forecasted to come in about the first five years with the rate of increase levelling to about 1.5% per year.

These two sources, both originating in the US, suggest that there is a scatter of increase rates about the 1.0% per year mark with one (for distillate fuel oil) of 0.7% per year (25 years), and one (TransCanada quoting US DOE for imported light sweet crude) of 2.6% (20 years). Based on this information, a base case is used with a 1.0% per year real increase (3.0% nominal with CPI rate of 2.0% per year), and a high case with a real increase of 2.0% per year.

Natural Gas price projections

1. One information source is the US Energy Information Agency's *Annual Energy Outlook 2010* presentation dated December 14, 2009 (delivered and published on website in early January 2010). Its forecast for natural gas prices at Henry Hub in constant dollars is for 0% increase to 2035 from the peak 2008 prices of \$8 to \$9 per MMBtu. However, starting from a low of \$6 to \$7 per MMBtu this represents a real increase of 1.0% to 1.5% per year. The forecast includes a dip in prices in 2009-2010
2. The other source was a presentation made by TransCanada Pipelines to Alaskan officials. It quoted information from the US DOE which forecasts the Alberta Hub price to increase to about \$7.60 per MMBtu in 2030. Depending on whether the starting point is \$5.30 or \$5.80 per MMBtu, this represents real increases of 1.4% to 1.9%.

Both forecasts referred to above predict a fairly rapid rise from present day prices over the next few years followed by a steady slow rise for the remainder of the forecast period. The forecasts of real increase range from about 1% to about 2%. Based on this information a base

¹² Leading Edge Projects Inc., Background Information to Leading Edge Projects' Assumptions, May 14, 2010

case is used with a 1% per year real increase (3.0% nominal with CPI rate of 2.0% per year), and a high case with a real increase of 2.0% per year.

Inflation/Consumer Price Index rate projection

1. The US Energy Information Agency's *Annual Energy Outlook 2010* presentation, referred to in oil price forecasts, projects energy prices up to 25 years into the future. This agency is forecasting real oil price increases of 1.0% to 1.1% and nominal price increases of 3%. The difference between the real and nominal oil price increase rate is the forecast general inflation rate. In this case the difference is 1.9% to 2.0%, which is implicitly the general inflation rate projected by this agency.
2. The Statistics Canada *Consumer price index, historical summary, by province or territory* table available from the Statistics Canada Web site (<http://www40.statcan.ca/101/cst01/econ150a-eng.htm>) provides Canadian consumer price index information. From this data the following general inflation rates can be calculated for various periods of time:
 - a. 2009: 0.26%
 - b. 2000-2008: 2.00%
 - c. 2000-2009: 1.83%
 - d. 1995-2009: 1.80%
 - e. 1990-2009: 2.01%
 - f. 1985-2009: 2.41%
 - g. 1985-1995: 3.35%

These two sources of data indicate that with the exception of 2009 (a year of significant economic downturn) the general inflation rate over the past 20 years has averaged about 2%. Preceding this, in 1985 to 1995, there was a period of higher inflation. An assumption of 2% per year of future general inflation would be consistent with the experience of the past 20 years and it is used in this study.

Wellhead and gas pipeline transmission costs

1. Wellhead gas cost \$5.23 per Mscf as per Attachment 1.
2. Yukon Mainline cost \$1.82 per Mscf as per Attachment 1. This makes the cost of gas at Stewart Crossing \$7.05 per Mscf. In this report Stewart Crossing is treated as the "hub" at which gas costs are inflated over time.

The Casino Lateral pipeline cost has been calculated on a cost per kWh basis (kWh of electrical load at the mine sites) similar to that for electrical transmission lines. It is treated as a separate project the cost of which is added to the electrical costs rather than to the gas costs. Electrical transmission costs are also treated in this manner.

As shown in Attachment 1, the cost of capital (blended debt and equity at 70% and 30% respectively) for pipelines is 8.77% before income tax.

Natural gas power generation

Capital costs outlined in the original E2M report for gas generation based on the GE LM6000 gas turbine (\$51,360,000 for a 42.8 MW unit or \$1.2 million per MW installed) are utilized as well as the operating costs of \$11.11 per MWh (\$0.01111 per kWh) since these costs are still judged to be valid. While the generating capacity required under various circumstances is not necessarily a round number of LM6000 generators required, the cost of capacity at \$1.2 million per MW is retained. The LM6000 is representative of mid-range gas turbine electrical generation systems. Fuel efficiency is determined to be 8.53 Mcf per MWh and the life expectancy is about 20 years.

Attachment 1 shows the cost of capital (blended debt and equity at 60% and 40% respectively) for mine site generation to be 9.40% before income tax which assumes a tax-paying utility, not a mining company. If the mining company made the investment, it would require a higher return. For utility owned generation the cost of capital was assumed to be YEC's present approved cost of capital of 6.54%. However, this rate cannot be directly comparable to the above rates because YEC does not pay income tax so no income tax is included in the number. Since the generation units are depreciated over the project life, no net salvage value is assumed. Note that the cost of capital is the "cost of service factor" less the depreciation. Then the depreciation period was adjusted in the spreadsheets as required (7, 10, 25 and 50 years). In regard to initial capital cost, the 10 and 25 year cases were dealt with as outlined below in order to keep the calculations relatively simple.

1. For a 10 year project life it was assumed that 110% of the capacity required for the project was purchased at the outset and depreciated over the 10 years. The extra 10% provides for a slight reduction in efficiency over time and an allowance for downtime for maintenance.
2. For a 25 year project life it was assumed that 150% of the capacity required for the project was purchased at the outset and depreciated over the 25 years. The extra 50% provides for a reduction in efficiency over time, an allowance for downtime for maintenance, and rotational use of units to ensure that the entire plant remains operative over 25 years.

LNG facilities

Plant facilities for the production of LNG are estimated to cost \$26 million for a capacity of 10 MMscfd (40 MW equivalent of electrical gas turbine generator output) and \$41 million for a capacity of 20 MMscfd (80 MW equivalent).¹³ Facilities to unload trucks, store the LNG and re-gasify it were estimated to cost \$1 million for a 2.5 MMscfd (10 MW equivalent) facility, \$4 million for a 10 MMscfd (40 MW equivalent) facility, and just under \$8 million for a 20 MMscfd (80 MW equivalent) facility. Since this study uses plant sizes from 5 MW to 100

¹³ All LNG costs are from Ellwood Energy Projects Ltd. - May 2010

MW, the costs for each plant size are proportioned to the 40 MW and 80 MW plant costs. The results are shown in the following table:

LNG Facilities	5 MW	50 MW	100 MW
Production	\$4.3	\$33	\$51
Unloading, storage, re-gasify	\$0.52	\$4.98	\$9.85
Total Costs	\$4.82	\$37.98	\$60.85

Costs expressed in \$millions

LNG production and re-gasification facilities are estimated to have a useful life of 25 years. The cost of capital is assumed to be 8.77% (same as pipeline facilities) and the annual O&M for these facilities is assumed to be 2.5% of initial capital cost increasing annually with the cost of general inflation. Again, this cost of capital is consistent with a utility and would not be the same as for a mining company.

LNG from Ft. Nelson for Selwyn/MacTung

LNG production at Ft. Nelson (from existing pipelines) for truck transport to Selwyn and MacTung is also examined. For the purposes of this study it was assumed that the Alberta Hub gas price of \$5.08 per Mscf would apply (see discussion on AHPP gas supply below). Facility costs consistent with those described above are assumed.

Recent information from a fuel trucking and distribution company indicates that transporting fuel by fully loaded Super B trucks in Yukon would cost in the range of \$7.50 to \$9.50 per loaded truck mile (all-in costs). This is equivalent to \$4.66 to \$5.90 per loaded truck kilometre. For the purposes of this report it is assumed that trucking of LNG would be \$4.66 per loaded truck - km would apply only to hard surfaced roads (paved and BST). A cost of \$5.90 per loaded truck - km is assumed for trucking on gravel surfaced roads. Trucking costs are assumed to increase at the same rate as general inflation.

A Super B fuel truck hauls about 46,000 litres or 10,130 Imperial gallons. One MMscf of gas converted to LNG is about 9,200 Imperial gallons, about 10% less than a Super B load of fuel. However, given that LNG trucking will require somewhat more specialized tankers, it was assumed that 9,200 Imperial gallons would constitute a full truckload. LNG trucking costs (per loaded truck - km) are thus equivalent to cost per MMscf.

The costs for LNG production and re-gasification, LNG trucking and for the AHPP connection facilities (pressure reduction, metering, and pipeline) in each of the applicable mine power supply cases are treated the same way as lateral pipeline and transmission line costs. They are each considered separate projects for which a levelized cost of energy (per kWh of electrical energy required at the mine sites) is calculated. These costs are then added to the cost of generating power with the source gas cost to yield the delivered costs of electrical energy per kWh at the mine sites.

Alaska Highway Pipeline Project (AHPP) gas supply

An option to generate electrical power at Whitehorse using gas from the proposed AHPP is assessed in this report. The cost of gas delivered from AHPP at Whitehorse is estimated to be \$3.61 per Mscf on the following basis. Sproule's natural gas price forecast for April 30, 2010 indicated that the Alberta AECO-C (the Alberta Hub) price for gas in the first four months of 2010 was \$5.08 (CDN) per Mscf. The cost of transport of gas from Alaska to the Alberta Hub was estimated by TransCanada to be \$US2.95 per MMBtu (November 30, 2007 in Application for License on P2.10-4). Backing out half of this cost (and assuming that for the purpose of this report the Canadian and US dollars are equivalent, and that 1MMbtu is equal to 1Mscf) the estimated cost of AHPP gas at Whitehorse would be $\$5.08 - \$1.47 = \$3.61$ per Mscf. This cost would increase over time by either 3% or 4% per year, which is the projected increase for gas prices (see previous discussion).

The capital costs for facilities to obtain gas from the AHPP and supply it to YEC generation facilities was based on information contained in the report "Estimated Costs for Providing Natural Gas to Yukon Communities."¹⁴ This report estimates that a pressure reduction and metering facility for 25 MMscfd would cost \$11.8 million (Table 3, page 7) and that a 10 km 6-inch diameter pipeline would cost \$4.8 million (\$80,000 per km) for a total capital cost of \$16.6 million. The cost of capital for these facilities is assumed to be 8.77% and O&M costs are estimated at 2.5% of the initial capital cost per year increasing at the rate of general inflation (consistent with other pipeline facilities).

Diesel power generation

For this analysis new low-RPM baseload diesel generators are assumed to be used. The installed cost for diesel generators is also about \$1.2 million per MW, and the operating cost is assumed to be \$0.02 per kWh, a figure used by YEC. Fuel efficiency is assumed to be 4.00 kWh per litre of diesel fuel and the life expectancy is about 20 years.

Late 2009 delivered fuel prices for YEC and Yukon Electrical Co. Ltd. are about \$0.85 per litre (equivalent to \$0.2125 per kWh) in road accessible locations, and this figure is adopted as the baseline for this study. The cost of capital considered to be appropriate for gas turbine generation equipment, 9.40%, was also used for mine site diesel generation. The units are depreciated over the project life and no net salvage value is assumed. In regard to initial capital cost, the 10 and 25 year mine life cases were dealt with as outlined below in order to keep the calculations relatively simple.

1. For a 10 year project life it was assumed that 115% of the capacity required for the project was purchased at the outset and depreciated over the 10 years. The extra 15% allows for maintenance downtime; diesel generators are a bit less reliable than gas turbines but with more units of smaller capacity there is more flexibility in dispatching them.
2. For a 25 year project life it was assumed that 150% of the capacity required for the project was purchased at the outset and depreciated over the 25 years. The extra 50%

¹⁴ Prepared by Wolf Island Engineering - March 31, 2009 and Revised August 10, 2009.

provides for an allowance for downtime for maintenance, and rotational use of units to ensure that the entire plant remains operative over 25 years.

Transmission line costs

Transmission lines of two different voltages occur in this report under different circumstances. The O&M costs for transmission lines are assumed to be 0.5% of the original capital costs. The capital costs for the transmission lines include any necessary substations. The installed costs for transmission lines are developed as outlined below. Depending on prevailing economic conditions at the time of construction, the installed costs may be conservatively high.

1. 25kV lines were assumed to cost \$300,000 per km. This is based on the Minto spur line having cost about \$10 million for about 29 km (about \$345,000 per km) with some downward rounding to allow for the fact that the Minto spur line involved a barge crossing of the Yukon River.
2. 138kV lines to big mines are assumed to cost \$600,000 per km on the basis that a high capacity line would cost more than the Carmacks to Pelly Crossing line (about \$300,000 per km) and the projected cost of the Pelly Crossing to Stewart Crossing line (including substations) of about \$533,000 per km.

Transmission line losses are assumed to be 10% of the energy sent out from the generation plant. This means that the YEC power generation facilities would need to be 11.1% larger than on-site facilities so that after transmission losses the required power supply is available at the mine site. The levelized cost of energy of line losses are thus 11.1% of the levelized cost of the actual electrical energy required by the mine on site.

Power supply to smaller mines

A case of a hypothetical 5 MW mine 160 km from Stewart Crossing and 25 km from the existing grid with an assumed seven year life is considered. For this case two options besides on-site diesel generation are considered. First, it is assumed that the present 138 kV grid would have sufficient capacity to route power to such a mine, and that the present industrial rate of about \$0.10 per kWh (average of energy and demand at about 80% load factor) is available at the point of interconnection. It is assumed that the 5 MW mine load would be served by a 25 kV line which originates at a new substation at the existing 138 kV line and terminates at a substation at the mine. A second option is to consider LNG produced at Stewart Crossing and trucked to the mine site for re-gasification and electricity generation.

Sensitivities

The base case assumes that inflation to be 2% and that all O&M costs are increased at the rate of inflation. Capital cost sensitivities of natural gas pipelines, electrical transmission lines, natural gas power generation facilities, LNG production and re-gasification facilities, and diesel generation facilities are not included in this study. The sensitivities examined are outlined below.

1. Natural gas price increases (at Stewart Crossing, Whitehorse, and Ft. Nelson): base case 3% per year (1% above inflation) and a high case of 4% per year.
2. Diesel fuel price increases: base case 3% per year (1% above inflation) and a high case of 4% per year.

The reason for only examining sensitivities related to energy costs is that those costs make up by far the largest component of delivered electric costs, often in the order of 50% or more of total costs.

Levelized cost of energy

All of the analyses are compared on the basis of the levelized cost of energy over the mining project life. The levelized cost of energy is calculated by dividing the sum of the discounted real annual costs over the life of the project by the discounted real annual energy production over the life of the project. The real discount factor used to calculate the annual values is $[(1+\text{cost of capital})/(1+\text{inflation rate})] - 1$. For the private pipeline investments examined in this update the real discount factor is $(1.0877/1.0200)-1 = 0.0664$ or 6.64%. For the private gas or diesel generation equipment investments examined in this update the real discount factor is $(1.0940/1.0200)-1 = 0.0725$ or 7.25%. For the YEC investments the real discount rate is $(1.0654/1.0200)-1 = 0.0445$ or 4.55%.

Greenhouse gas (GHG) emissions

In this study only GHG emissions related to the operating fuel of the generating plants are calculated (this includes electrical generation to compensate for line losses). The GHG emissions that would have resulted from manufacturing the equipment, the construction of facilities, and indirectly from the operation of the facilities (fuel transport by truck, LNG production and re-gasification, building heating, small vehicle use, maintenance vehicle use, etc.) are not considered. This level of detail is beyond the scope of this study, but could be considered in a more comprehensive assessment.

Environment Canada data for the CO₂, CH₄, and N₂O emitted from the combustion of natural gas and diesel fuel are used to calculate the overall GHG emissions. The presently accepted United Nations global warming potential for CH₄ and N₂O expressed as CO₂ equivalent are used to calculate the overall GHG emissions in CO₂ equivalents (CO₂ eq). The factors are 21 for CH₄ and 310 for N₂O.

The combustion of a litre of diesel fuel results the production of 2663g of CO₂, 0.133g of CH₄ and 0.4g of N₂O. The GHG emissions in CO₂ eq is thus: $2663\text{g} + (0.133 \times 21)\text{g} + (0.40 \times 310)\text{g} = 2789.8\text{g}$ or 2.7898kg CO₂ eq. At the assumed large baseload diesel efficiency of 4.0kWh per litre assumed for mine power supply, the CO₂ eq produced per kWh is 0.6975kg CO₂ eq per kWh, or 697.5 tonnes CO₂ eq per GWh.

Environment Canada lists the CO₂ produced per m³ of natural gas by province as composition varies a bit across the country. The CO₂ emitted from gas combustion in western Canada at 1916 to 1918g per m³ is slightly higher than in eastern Canada where it is 1877 to 1879g per m³ (with only Saskatchewan being lower at 1820g and Northwest Territories being higher at 2454g). These numbers converge around the figure of 1890g CO₂ that is reported in the US as

based on the US EIA gas composition data. For the report a figure of 1890g CO₂ per m³ of gas is adopted.

Environment Canada list single numbers for the CH₄ and N₂O emissions from the combustion of gas by electric utilities, those being 0.49g and 0.049g per m³ respectively. The GHG emissions expressed as CO₂ eq per m³ of gas combusted is thus 1890g + (0.49 X 21)g + (0.049 X 310)g = 1915.5g or 1.9155kg CO₂ eq. When combusting natural gas in a turbine at an efficiency of 8.53Mcf/MWh (8.53cf per kWh) the GHG emissions would thus be about 462.6g of CO₂ eq per kWh or 462.6 tonnes CO₂ eq per GWh.

Field Development Costs

During the regulatory review of the Mackenzie Valley Gas Project (MGP), the Government of Yukon was an active intervener in the National Energy Board hearings. The purpose of the intervention was to ensure that Yukon's natural gas resources were not overlooked by the project proponents and that the tolling structure and lateral policies were not detrimental in allowing Yukon natural gas to market via the Mackenzie Valley Pipeline. As a result, much analysis and modeling of the Eagle Plain Basin has already been completed by consultants representing the Yukon government and the MGP proponents.

Further, the Government of Yukon also commissioned Fekete Associates Inc. to do an in-depth review of the Eagle Plain basin in order to evaluate its economic attractiveness for development and production of the basin's large natural gas resources.

These two separate analyses have been used in this study to determine the following field production cost estimates.

MGP's reservoir consultants, Gilbert, Laustsen and Jung Associates (GLJ)¹⁵ determined, for Eagle Plain, that the marketable gas resource per pool was 31.38 Bcf. This was based on a 114 pool probability with:

- an estimated discovered marketable gas resource of 47 Bcf;
- an undiscovered marketable gas resource of 3,530 Bcf; and
- a marketable gas total of 3,577 Bcf.

For the Field Development Cost estimates, two wells per pool were estimated to be required for adequate drainage based on the small average pool size of 12 MMcf/d per pool. In order to provide the Yukon pipeline grid with 50 MMcf/d, several pools would have to be developed and produced and brought on stream over the life of this study as the original pools decline.

Based on the GLJ MGP work done on the Eagle Plain basin, the following estimates were derived:

Drilling and completing two wells:	\$12 million
(drilling at \$3,000/m; well depth of 1500 m; \$500,000 well pad; \$500,000 completion and a 10% contingency)	
Flow lines to gathering system:	\$13.5 million

¹⁵NEB Hearings, Mackenzie Gas Project, GLJ Response to Yukon IR #2.2 - May 2005, page 8.

(18 km of NPS 6 pipe based on \$125,000 per diameter-inch/km)

Processing facility and compression: \$11.4 million

(\$1 million/MMcf/d with a flow rate per pool of 12 MMcf/d for eight years at 345 days/year)

Total Field Development: \$36.9 million per pool

From Confer Consulting's analysis in Attachment #1,

Annual unit cost for capital recovery: \$1.83 per Mcf

And, from the Fekete Report,¹⁶

Field Operating Unit Costs: \$0.90 per Mcf

Raw gas cost including royalties: \$2.50 per Mcf

Total unit field costs @100% load factor are \$5.23 per Mcf

¹⁶ North Yukon Conceptual Oil and Gas Development Scenario and Local Benefits Assessment, November - 2005, Table 8.

Attachment #5

Cost Estimates for the Use of Trucked LNG in Yukon¹⁷

All Costs in 000's \$, Q2, 2010				
LNG Plant Site	10MW	20MW	40 MW	80 MW
	2.5 MMSCFD	5 MMSCFD	10 MMSCFD	20 MMSCFD
LNG Plant	\$6,000.0	\$11,000.0	\$18,000.0	\$27,000.0
Civil	\$78.0	\$78.0	\$78.0	\$78.0
Piping	\$20.0	\$30.0	\$50.0	\$87.5
Electrical	\$6.5	\$9.7	\$16.2	\$28.3
Bldgs	\$125.0	\$150.0	\$175.0	\$200.0
Tanks	\$750.0	\$1,500.0	\$3,000.0	\$6,000.0
Total Directs	<u>\$6,979.5</u>	<u>\$12,767.8</u>	<u>\$21,319.2</u>	<u>\$33,393.9</u>
Eng & PM	\$523.5	\$957.6	\$1,598.9	\$2,504.5
Contingency	\$1,046.9	\$1,915.2	\$3,197.9	\$5,009.1
Camp & Catering	\$10.2	\$15.3	\$25.5	\$44.6
Total Indirects	<u>\$1,580.6</u>	<u>\$2,888.0</u>	<u>\$4,822.3</u>	<u>\$7,558.3</u>
Total Cost	\$8,560.1	\$15,655.8	\$26,141.6	\$40,952.1
Stewart Crossing Facilities				
Tanks	\$750.0	\$1,500.0	\$3,000.0	\$6,000.0
Load/unload	\$60.0	\$90.0	\$150.0	\$260.0
Regassifier	\$40.0	\$60.0	\$100.0	\$175.0
Total Directs	<u>\$850.0</u>	<u>\$1,650.0</u>	<u>\$3,250.0</u>	<u>\$6,435.0</u>
Eng & PM	\$63.8	\$123.8	\$243.8	\$482.6
Contingency	\$127.5	\$247.5	\$487.5	\$965.3
Total Indirects	<u>\$191.3</u>	<u>\$371.3</u>	<u>\$731.3</u>	<u>\$1,447.9</u>
Total Cost	\$1,041.3	\$2,021.3	\$3,981.3	\$7,882.9
Grand Total	\$9,601.4	\$17,677.1	\$30,122.9	\$48,835.0

¹⁷ Ellwood Energy Projects Ltd., May - 2010

Attachment #6

Cost Estimates for Providing Natural Gas to Yukon Communities¹⁸

Table 3: Cost Estimates for Yukon Pressure Reduction & Metering Facilities

Community	Population in 2006¹⁹	Estimated Total Gas Demand²⁰ (MMscf/d)	Estimated Capital Cost²¹ (\$M)
Beaver Creek	112	0.2	2.1
Burwash Landing	73	0.1	2.1
Destruction Bay	55	0.1	2.1
Haines Junction	589	0.7	2.8
Whitehorse	22,114	25.0	11.8 ²²
Teslin	297	0.4	2.8
Upper Liard	178	0.2	2.1
Watson Lake	846	1.3	4.2
Total	24,118	28.0	30.0

The Whitehorse Lateral is estimated to be \$4.8 million CDN when using the off-highway cost of \$80,000 per diameter inch km. This estimate is based on a flow rate of 25 MMscfd using a 6 inch diameter and a distance from the AHPP pipeline to Whitehorse of 10 km.

Since Yukon is not connected to the North American natural gas grid there is no commodity market for natural gas. For the purpose of this study the estimated cost of development is used to establish the price of gas at the source. The actual price will be a negotiated price between the gas provider and its customer. If there are two or more customers the price will be established by the utility board with the goal of protecting the interests of both the customers and the gas company.

¹⁸ Estimated Costs for Providing Natural Gas to Yukon Communities, Wolf Island Engineering - revised August 10, 2009

¹⁹ Bureau of Statistics, Executive Council Office, Yukon Government – 2006 Census.

²⁰ Interpolated and extrapolated from NWT Community Gas Demand estimates.

²¹ Estimated from similar sized communities in NWT.

²² Conversations and e-mails with Jack Beattie, TCPL - August 26, 2009