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Viability Of Using Northern Oil And Gas Reserves To Supply Energy For Mining And Community Needs
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VIABILITY OF USING NORTHERN OIL AND GAS RESERVES TO SUPPLY ENERGY FOR MINING AND COMMUNITY NEEDS
Sector: Mining/Oil/Energy

6-5-27
Analysis/Review

NOGAP H53-1

Viability of Using Northern Oil and Gas Reserves to Supply Energy for Mining and Community Needs

Presented to:
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Viability of Using Northern Oil and Gas Reserves to Supply Energy for Mining and Community Needs

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DISCLAIMER: The conclusions and recommendations of this study are those of NORTH OF 60 ENGINEERING LTD. and do not necessarily represent the policies, views and/or opinions of EMPR or other agencies of the Government of the Northwest Territories.

The conclusions are based on a number of assumptions that have been made for the purposes of this study. They may need to be modified, on a case by case basis as economic and other conditions change over time, and must be re-confirmed prior to acceptance by the user.

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Executive Summary

The mining industry is currently the largest independent economic sector in the Northwest Territories representing about 70 per cent of the goods exported from the NWT. Operating mines in the Northwest Territories currently produce zinc, gold, lead, and silver. Development of recent discoveries, in particular the base metal mine at Izok Lake, could provide a significant economic uplift. Economical development of these resources, however, is dependent on a number of important factors, one of which is the cost of energy.

Energy costs are a large component of the operating costs for northern mines. Traditionally, diesel and heavy fuel oil have been supplied from southern refineries. Mines located in the western Northwest Territories have been supplied from the small refinery at Norman Wells and larger refineries in Edmonton, while eastern NWT mines have primarily been supplied from refineries in Eastern Canada and offshore. Energy costs in the region are high because of the long transportation distances and storage costs to support year round operations. The high costs frustrate industry, the government and residents because the region is rich in oil and gas reserves.

The purpose of this study was to assess the economic viability of developing some of the known reserves in the region, to supply cheaper energy for the communities and the mining operations in the Mackenzie Delta, the West Kitikmeot and the High Arctic.

The communities in the Northwest Territories require. fuel for heating, electricity and transportation. Fuel for heating and electricity represents threequarters of the total annual demand, which is approximately 70,000 m' for the eleven immunities considered in this study (see Table 1).

The potential mining demand is significant. Operating mines in the Northwest Territories consume 45,000 m' per year of diesel and the additional demand for future new mines is estimated to be more than 100,000 m' per year. As in the communities, most of the fuel is used to produce heat and electricity.

This study has concentrated on the stationary diesel demand for the communities and mining industry, i.e. excluding transportation. Three demand scenarios were considered with the total demand for diesel ranging from just over 130,000 m' per year to 230,000 m' per year.

A number of supply options were considered in the study. These included:

- Conventional supply from refineries in Eastern Canada, Edmonton and Norman Wells.
- Back hauling of diesel from Europe or Southern Canada. The ore carriers the mines would use to transport their product can be upgraded to allow them to carry both concentrate and fuel, thus providing the possibility of back hauling diesel at a very low cost from offshore sources of supply.
- The development of some of the discovered oil reserves in the area, to provide a feed stock for a northern refinery (topping plant).

Three northern hydrocarbon development alternatives were considered for this study. They included:

- the Atkinson oil field, one of the smaller onshore reservoirs in the Mackenzie Delta,
- seasonal production from the Amauligak field in the Beaufort Sea, and
- existing production from the Bent Horn field in the High Arctic.

Development plans were prepared for the two Beaufort fields. Topping plants were sized and costed for the three locations. It was assumed for the purposes of this study that the topping plants would produce three products, naphtha, diesel and a residual crude. The first two products would be used in the Northwest Territories, while the residual would be transported on a seasonal basis to southern markets. Product storage would be required for all three products due to the seasonal nature of the transportation systems.

A supply cost model was prepared to analyze the numerous alternatives. The model has three inputs, the demand, the product supply cost and the transportation costs to move the product from supply source to the end user.

Product supply costs for local energy supplies were calculated to net both the refiner and the producer a 15 per cent return on their investment and operating costs. Local landed costs for P50 diesel prices range from a low

$198 /m³ for product from Edmonton to a high of $392 /m³ for product from Bent Horn.

Transportation alternatives considered included:

- river barges and tugs
- ice-reinforced ocean going barges
- 40,000 dead weight tonne (DWT) capacity ice reinforced, combination ore-bulk-oil (OBO) carriers.

Transportation costs were calculated to move product from the supply alternatives to the communities and a mining terminal in the Coronation Gulf using various combinations of the above vessels.

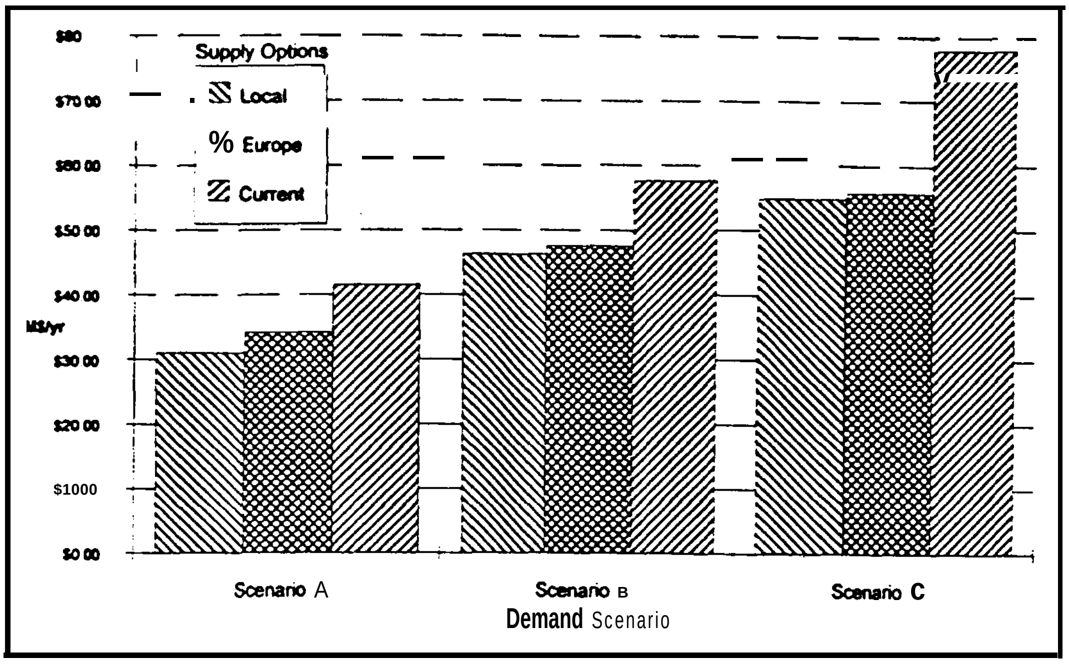
The supply model was used to determine the minimum supply cost for three different options. They were:

- current supply sources, i.e. Montreal, Edmonton and Norman Wells
- current supply sources, plus local topping plants at Tuk and/or Bent Horn
- current supply sources, plus Europe.

The results of the analysis are summarized in Figure 1. From a cost standpoint, the results show that local energy supplies yield the lowest supply cost for all three demand scenarios. Back hauling from Europe is a close second while utilizing current sources is clearly the most expensive.

Europe can supply product into Coronation Gulf at a slightly cheaper cost than a topping plant located in the Mackenzie Delta. This is evident, if for example, the community demand is dropped from Scenario B. In this example, the supply cost is 27.8 M$ per year from Europe and 31.6 M$ per year using local sources. Thus, from a mining perspective, supply from Europe is slightly more attractive.

A local topping plant would produce approximately 175,000 m' of heavy fuel oil (HFO) per year. Given today's technology, there is also the possibility that mines such as Izok Lake could use this fuel as an alternative to diesel for much of their energy demand. If for example, the mines could use HFO for 50 per cent of their energy needs, and if the rack price were 25 per cent of diesel, the total supply cost for the mining demand in Scenario B is reduced to 23.2M$ per year. This compares favorably to the European alternative for diesel at 27.8M$ per year - making the local supply option cheaper.



Diesel Supply Cost
Figure 1

A number of important conclusions can be drawn from this study. They are:

- **Northern hydrocarbon resources can be economically developed to meet the energy needs of the mining industry and local communities.**
- **Northern hydrocarbon resources can compete in the market place with alternative energy sources such as back hauling of product from Europe, or supplying product from existing sources.**
- **A Northern topping plant would produce heavy fuel oil which could potentially be used by the mines as an inexpensive source of energy.**
- **Unlike alternative sources, the development of local energy supplies would provide significant benefits. These include local employment and training, economic benefits to the region, and the opportunity to attract new business into the Northwest Territories.**

Introduction

Study Objective

The objective of the study was to assess the economic feasibility of developing the discovered reserves in the Mackenzie Delta, Beaufort Sea and Arctic Island regions as an energy supply for northern mining operations and local communities.

Background & Rationale For Study

The mining industry is currently the largest independent economic sector in the Northwest Territories representing about 70% of the exports from the NW. Operating mines in the Northwest Territories currently produce zinc, gold, lead and silver. Development of recent discoveries, in particular the potential zinc, copper and lead mine at Izok Lake, could provide a significant boost to the economy of the Northwest Territories. However, economical development of these resources is dependent on a number of factors, including the capital cost to develop the ore body and transportation infrastructure, and anticipated commodity prices and operating costs.

Energy costs are a significant component of operating costs in the northern mining industry. Traditionally, diesel and heavy fuel oil have been supplied from southern refineries. Mines located in the western Northwest Territories have been supplied from the small refinery at Norman Wells and larger refineries in Edmonton, while eastern NWT mines have primarily been supplied from refineries in Eastern Canada and offshore. Energy costs in the region are high because of the long transportation distances and storage costs to support year round operations.

The high energy costs in the region frustrate industry, the government and residents because the region is rich in oil and gas reserves. Exploration for oil and gas dates back to the discovery of the Norman Wells field in the early 1920s. To date the extensive exploration programs carried out in the Mackenzie Delta and the Beaufort Sea during the past quarter century have discovered more than 200 million m^3 of recoverable oil and 300 billion m' of recoverable gas. Farther north in the Arctic Islands (Sverdrup Basin), industry has discovered 80 million m^3 of recoverable oil and 480 billion m' of recoverable gas.

Production to date includes only the Norman Wells field on the Mackenzie River, the Cameron Hills area near the Alberta border and a small seasonal production operation at Bent Horn in the Arctic Islands. One reason for the lack of hydrocarbon development is that high-cost transportation systems are needed to move the product to southern markets. Yet a smaller, but still significant, local market could develop if one or more of the recently discovered mineral deposits were developed.

The purpose of this study was to assess the economic viability of developing some of the discovered reserves in the region to supply cheaper energy for the communities and the mining operations in the Mackenzie Delta, the West Kitikmeot and the High Arctic as shown in Figure 2. Development of these reserves would provide significant benefits to the region. These include employment and training opportunities, income in the form of taxes and royalties, and opportunities for spinoff business associated with oil and gas development.

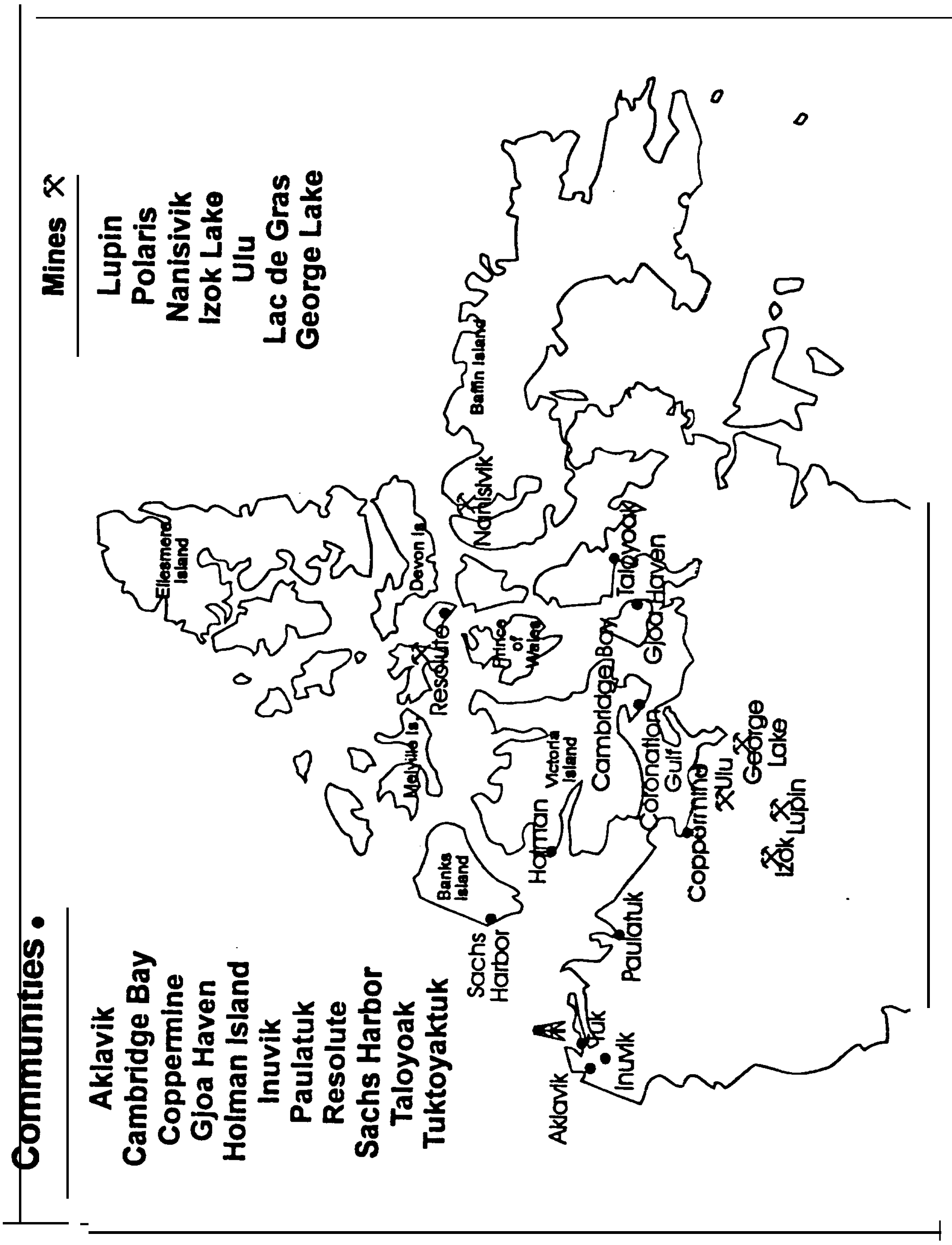
Scope of Work

As indicated, the objective of this study was to assess the economic feasibility of developing the discovered reserves in the Mackenzie Delta, Beaufort Sea and Arctic Islands as an energy supply for northern mining operations and local communities.

This objective was addressed through seven tasks, which in essence, represent the deliverables of the study.

Task 1 identified the existing and future demand in the following areas:

- Communities (listed in Figure 2)
- Mining Industry
  - Current operations
  - Potential developments
- Hydrocarbon Exploration and Development



Community & Mine Locations
Figure 2

Three development / demand scenarios were considered based on various levels of mineral activity in the region. They are summarized in Table 4.

Task 2 identified potential fuel supply options in the region from the existing discovered reserve base. These included the onshore and offshore reserves in the Mackenzie Delta region as well as onshore reserves in the Arctic Islands.

Task 3 identified the associated production scenarios, the production and processing technology requirements, and the costs for each of the supply options.

Task 4 identified the transportation alternatives to move the production or refined product to market. These included but were not limited to:

- Pipelines
- Tankers - seasonal
- Tankers - year round
- Fuel Barges - seasonal
- Others - electrical power generation and transmission
  - trucking

Task 5 established the economic feasibility of selected alternatives.

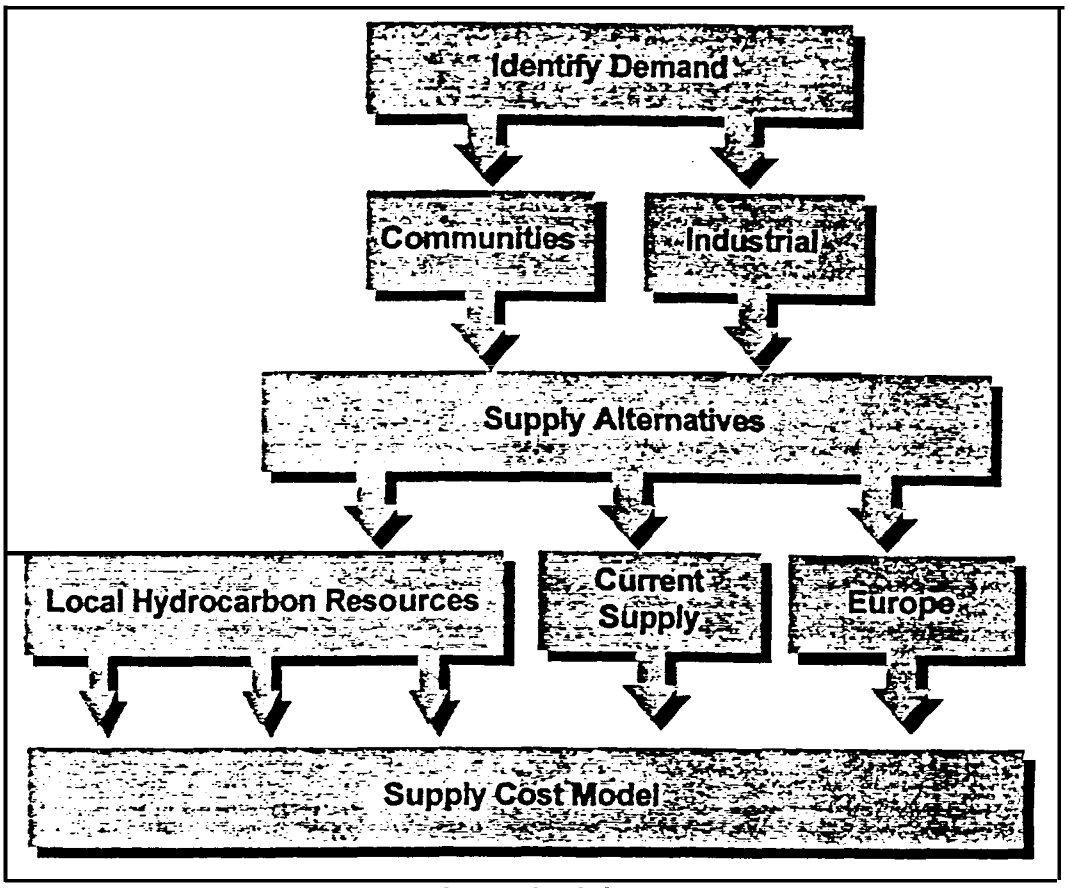
Task 6 identified the spinoff businesses, employment and economic opportunities associated with the various alternatives.

And finally, Task 7, this report, documents the results of the study.

Study Methodology & Assumptions

Figure 3 is a block diagram of the process that was used to assess the economic viability of developing local hydrocarbon resources to compete with existing supply sources or potential supply sources such as hydroelectric power, or the back haul of refined product from Europe.

The first step was to investigate and quantify the type, and volumes of petroleum products that are used by the communities and mines considered in this study (Figure 2). That investigation clearly showed that diesel represents over 85 per cent of the fuel consumed. Therefore, the other fuels (Turbo, and Motor Gasoline) were not considered in the study in order to simplify the analysis. The diesel requirements were quantified into three demand scenarios as outlined in the terms of reference for the study.



Study Methodology
Figure 3

The next step in the process was to identify the current means of supplying diesel fuel to the specific communities and mines and to identify possible alternative energy sources that could produce a compatible fuel. Three sources were identified. They included both onshore and offshore development in the Mackenzie Delta region, and the existing production from the Arctic Islands. Based on the results of a previous study[1], the development of existing gas reserves was dropped because of the high costs required for transportation and storage.

The economic viability of developing the three oil options was then determined. This required an identification and assessment of likely development costs, production rates and operating costs for each.

Capital and operating costs for each supply option were established using the Northern Regions Venture Cost Model developed by NORTH OF 60

ENGINEERING LTD. Production forecasts were calculated for each option using a decline model commonly accepted by the petroleum industry. The production profile for each reservoir was based on a constant percentage decline. The initial production plateau was calculated on a relatively conservative reserve life index of 10 to 13 years, depending on the size of the reserve base. The production decline was assumed to commence after 40 per cent of the recoverable reserves had been produced.

The economic viability of each development option was assessed on a $20 US/barrel flat (in constant 1993$) price forecast for West Texas intermediate Oil in the Chicago market place. This assumption is in line with the views of most of the industry at this time. The inflation rate was assumed to be 4 per cent per year and the exchange rate was assumed to be 0.80 $Cdn/$US. Royalties were calculated using the generally accepted Canadian Petroleum Resource Act (CPRA) royalty structure. The economic analysis established a fieldgate price for the crude which would yield the producer a reasonable fate of return, assumed at 15 per cent per annum.

The economic viability of producing diesel using local topping plants was then assessed. Again, this required an appraisal of capital investments, operating costs and product yields. Some of the key assumptions in this analysis were that all three crude sources examined in this study would yield the same percentage of diesel per unit volume of crude. Other important assumptions were that the small amount of naphtha production could also be sold at diesel prices and that the price of the reduced crude would cover transportation costs to southern markets; i.e. it is of no value to the topping plant owner. Both of these assumptions are relatively conservative. In reality, there is an opportunity for the larger consumers such as the mines to use the cheaper heavy fuel oil as a source of energy. The bottom line of this analysis, though, was to establish a diesel price at the plant gate, commonly referred to as the rack price.

The final step in the analysis was to assess the transportation costs to move the product from the topping plant sites to the communities and ports supporting the mine sites. This entailed an analysis of existing barge rates, and the detailed transit analysis for ship traffic in the Coronation Gulf. The transportation costs were then coupled with product costs and diesel demand in a Supply Cost Model developed for the study to determine the minimum supply cost for all possible alternatives.

A number of assumptions have been made to simplify the assessment. The author believes that these assumptions do not harm the accuracy of the results of the study, nor do they alter the conclusions and recommendations.

Hydrocarbon Demand

Eleven communities, three operating mines and three potential new mines were considered in the study. The locations of the communities and mines are shown in Figure 2. The following sections identify the community and industrial energy demand.

Communities

Northwest Territories communities require fuel for heating, electricity production and transportation. Tables 1 & 2 summarize the 1989 fuel consumption under these three general classifications for the communities considered in this study. Table 1 represents the stationary demand, i.e. the demand for heating and electricity, while Table 2 summarizes the transportation demand.

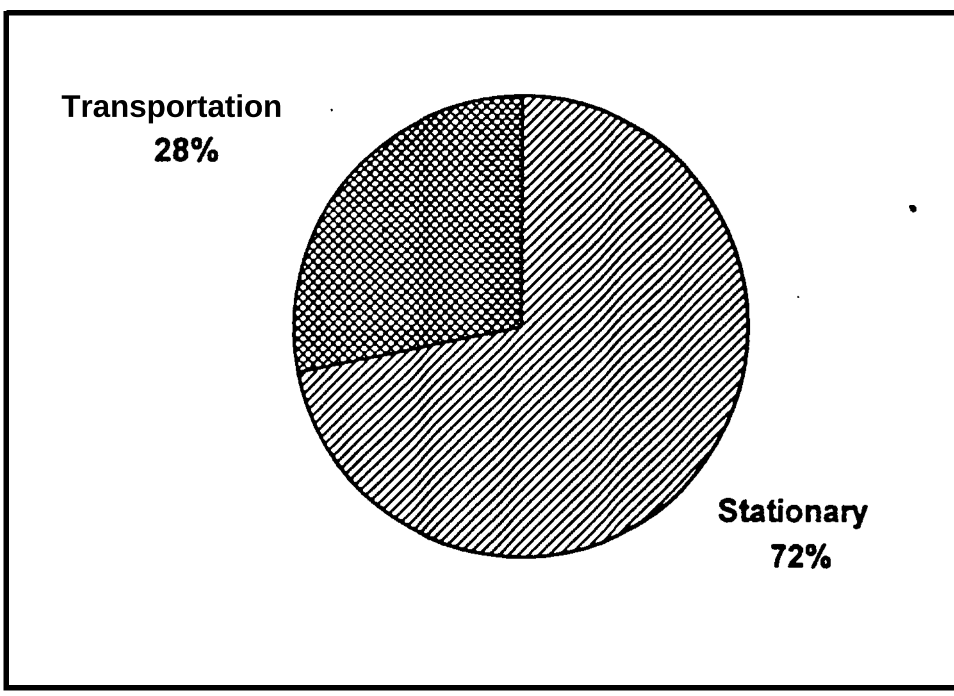
Communities	Population	Heating Demand P50 m³/yr	Heating Demand HFO m³/yr	Electrical Generation P50 m³/yr	Electrical Generation HFO m³/yr	Total HFO EQUIV m³/yr
Aklavik	755	1,515	0	937	0	2,452
Cambridge Bay	995	3,092	0	1,662	0	4,755
Coppermine	885	1,806	0	1,023	0	2,829
Gjoa Haven	650	1,385	0	807	0	2,192
Holman Island	305	1,027	0	511	0	1,538
Inuvik	3,380	10,573	8,226	2.787	6.271	29,252
Paulatuk	190	433	0	244	0	677
Resolute	185	597	0	1,848	0	2,445
Sachs Harbor	155	525	0	364	0	889
Taloyoak	490	1,513	0	787	0	2,300
Tuktoyaktuk	925	2.487	0	1,619	0	4,106
Tots	8,915	24,953	8,226	12,588	6,271	53,432

1989 Community Stationary Demand Source: EMPR
Table 1

Communities	Diesel m³/yr	Gasoline m³/yr	Av Gas m³/yr	Turbo m³/yr
	Transportation Demand			
Aklavik	0	614	0	0
Cambridge Bay	0	403	235	1,135
Coppermine	79	519	116	374
Gjoa Haven	0	343	1	0
Holman Island	0	209	19	338
Inuvik	3,792	4,352	1,475	4,970
Paulatuk	0	87	0	0
Resolute	0	24	0	0
Sachs Harbor	0	107	0	121
Taloyoak	0	283	144	273
Tuktoyaktuk	352	688	0	9
Total	4,222	7,629	1,991	7,221

1989 Community Transportation Demand Source: EMPR
Table 2

As shown in Figure 4, the stationary demand for heating and electricity is significantly larger than the transportation demand.



Community Fuel Demand
Figure 4

There is a good correlation between the stationary demand and the population within the various communities. The population in these communities has been relatively stable, having grown from 6,459 in 1971[2] to 8,518 in 1988[3]. This represents a growth rate of just over 1.5 per cent per year. The non-indigenous part of this growth and future growth are dependent on the local economy. The 1988 census figures show population shifts. In all likelihood, the population in the towns of Inuvik, Tuktoyaktuk and Coppermine would grow if mining and hydrocarbon development were to take place; however, this growth would have little impact on the overall energy demand picture.

Mining Operations

Fuel demand for the operating mines and potential future mines is summarized in Table 3. As with the communities, most of the consumption is stationary, with most of the energy being converted to electricity and heat.

Mines	Ore Mined MTonnes/Yr	P50 Fuel Demand m³/Yr
Operational		
Lupin	0.8	20,000
Polaris	1.0	16,000
Nanisivik	0.7	10,000
Potential		
Izok Lake	1.1	21,000
Ulu	0.3	7,000
Lac de Gras	3.5	55,000
George Lake	1.0	20,000
Sub Total	8.4	149,000

Mining Energy Demand: EMPR (Estimates)
Table 3

Table 3 shows that the potential mining demand is certainty significant. It represents almost twice the current community demand, 'and is clearly one of the major factors in determining the economic viability of current operations and the potential for future developments.

Petroleum Exploration and Development

Petroleum exploration in the region has, historically, also represented a significant demand for refined petroleum products. Exploration in the mainland part of the NWT began in the early 1920s and resulted in the discovery of the Norman Wells oil field by Imperial Oil Resources Ltd. in 1920. Shortly after its discovery, Imperial built a small refinery to produce gasoline and diesel fuel for the local market. As mining activity increased, a larger refinery was built in 1939 and later expanded in the early '40s to supply the wartime CANOL pipeline. Increasing demand in southern Canada led to the most recent expansion of the field in the mid 1980s when the InterProvincial Pipeline was built from Norman Wells to Zama, Alberta.

Exploration in the Mackenzie Delta - Beaufort Sea region of the Northwest Territories began in the early 1960s. Since then, more than 200 wells have been drilled, more than half offshore. Demand for refined product to support the exploration effort during the peak of the activity in the mid 1980s was in the order of 100,000 m' of diesel fuel per year. In spite of the significant reserves that were discovered during the 1970s and 1980s, the economic outlook for frontier development has changed radically due to a significant drop in oil prices. Exploration activity in the region had dropped to a 25 year low. The small effort currently going on is focused on finding additional onshore reserves to make an extension of the InterProvincial Pipeline to the Beaufort economically viable. For this study, the authors have assumed a modest level of activity, representing three wells per year consuming 5,000 m^3 of diesel per year. A high case, of 10,000 m' per year was also considered to reflect increased activity in the region, which might result from successful exploration programs or development of current discoveries.

Demand Volumes

This section summarizes the demand volumes considered in this study.

An analysis of the fuel demands in the previous section clearly shows that diesel is the predominant fuel used in the Northwest Territories. It represents over 80 per cent of the current fuel consumption and this percentage could grow, depending on the number of mines developed and the extent of hydrocarbon exploration and development. For this reason, this study has focused on stationary diesel demand to simplify the analysis.

As requested by the Department of Energy, Mines and Petroleum Resources, GNWT, NORTH OF 60 ENGINEERING LTD. has considered the three demand scenarios summarized in Table 4.

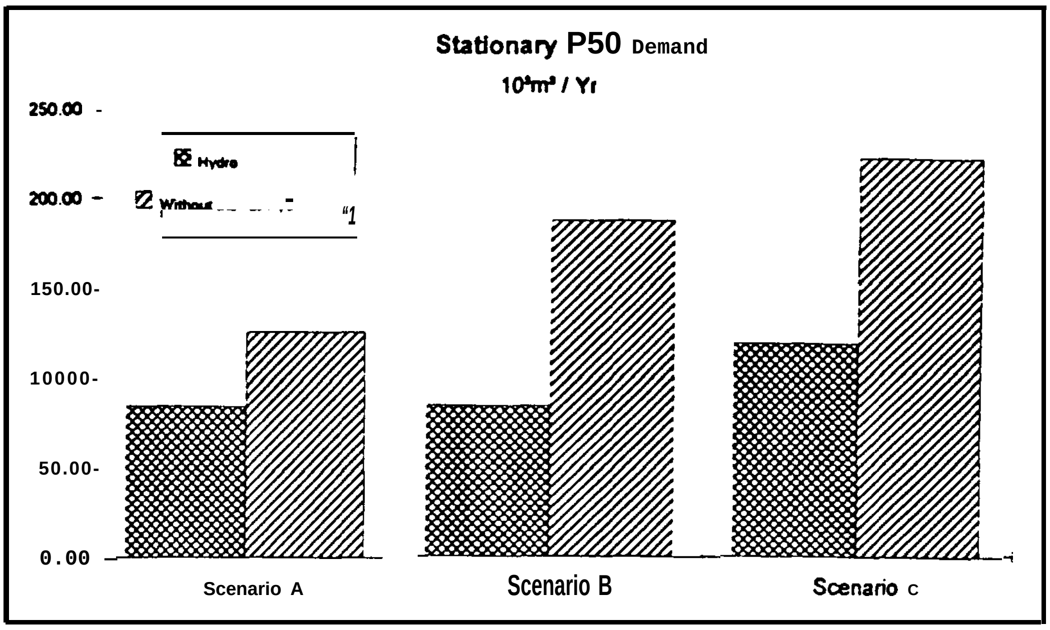
The diesel demand for these scenarios is presented in Table 5 and summarized in graphic form in Figure 5.

Scenario A EXCELLENT POTENTIAL OF PROCEEDING WITHIN THREE YEARS	Scenario B REASONABLE POTENTIAL OF PROCEEDING IN THREE TO FIVE YEARS	Scenario C MODEST POTENTIAL OF PROCEEDING IN MORE THAN FIVE YEARS
Communities Mining Lupin Polaris Nanisivik	Communities Mining Lupin Polaris Nanisivik	Communities Mining Lupin Polaris
Izok Lake	Izok Lake Ulu Lac de Gras	Izok Lake Ulu Lac de Gras George Lake Smelter

Demand Scenarios
Table 4

As evident from Figure 5, the total demand for diesel fuel ranges from just over 125,000 m^3 per year in Scenario A to 220,000 m' per year in Scenario C.

Also, shown in Figure 5, is the potential impact of hydroelectric power generation on the total demand. There are a number of possible locations for hydroelectric power generation within the Coppermine River basin. If, for example, a 68 Megawatt plant were to be built at Rocky Defile, one of the possible locations, it could service the energy demands of the Lupin and Izok Lake mines in Scenario A, and still have additional capacity to feed the Ulu and Lac de Gras operations, that are incremental in Scenario B. This would drop the diesel demand to 84,000 m^3 per year in Scenario A and B and to 120,000 m^3 per year in Scenario C. The potential impact of hydroelectric development on the results of this study will be addressed later in this report.



Diesel Demand by Scenario
Figure 5

Diesel Demand 10^3m^3/yr	Scenario A		Scenario B		Scenario C	
	Hydro	No Hydro	Hydro	No Hydro	Hydro	No Hydro
communities	53.43	53.43	53.43	53.40	53.43	.53.43
Petroleum Industry	5.00	5.00	5.00	5.00	10.00	10.00
Mining Industry	26.00	67.00	26.00	129.00	56.00	159.00
otal Demand	84.43	125.43	84.43	187.40	119.43	222.43

P50 Diesel Demana
Table 5

Supply Options

Supply from Existing Sources

Petroleum products for the Northwest Territories are supplied from refineries in Eastern Canada, Alberta, Norman Wells, and offshore.

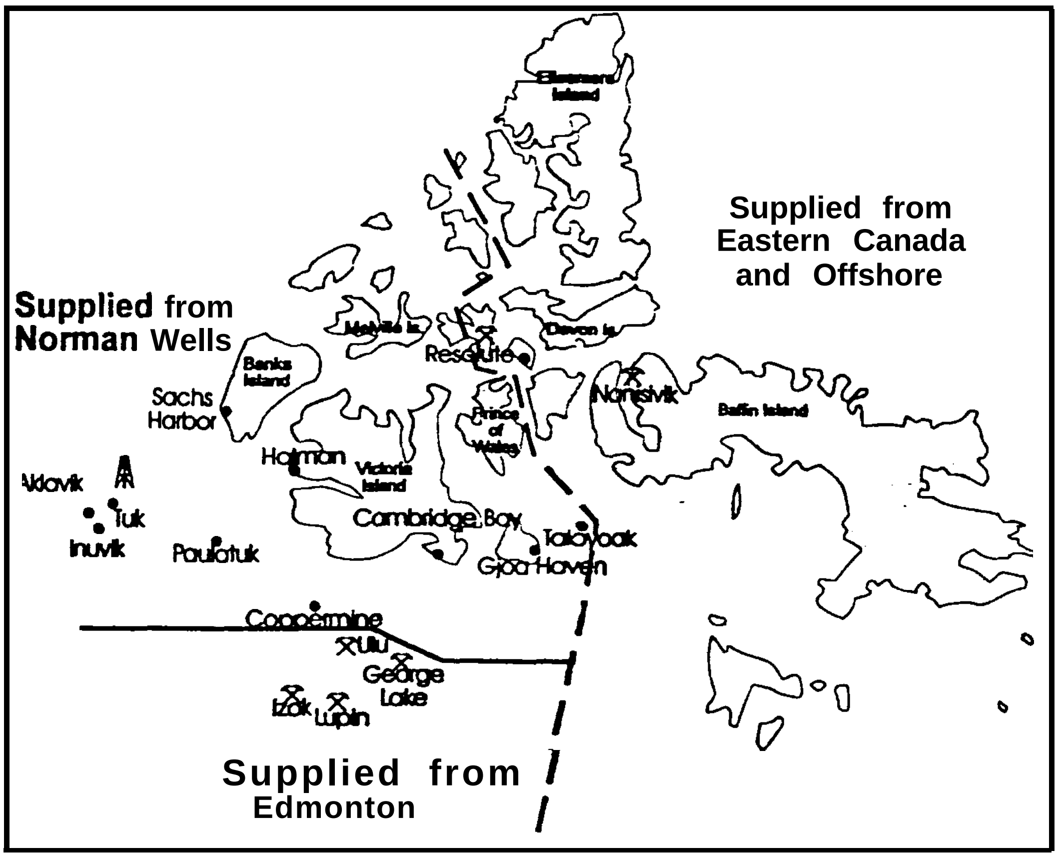
Generally speaking, the communities east of Taloyoak and the mines at Nanisivik and Polaris are supplied from refineries in Eastern Canada. The mainland region of the Northwest Territories is, generally, supplied from refineries in Edmonton and the communities north of Norman Wells and east to Taloyoak are supplied from Norman Wells. See Figure 6.

Many communities in the Northwest Territories are not sewed by the private sector distributors of petroleum products. Where the private sector is unable to establish an economically viable service, the GNWT, through the Petroleum Products Division, acquires, arranges transportation for, stores and distributes fuels.

Supplying refined product into this region is expensive. High transportation and storage costs result from generally small demand within the communities, their remoteness, harsh climate, and lack of year round transportation systems. Supply trips are infrequent.

Product from the East Coast is shipped once a year to the Polaris and Nanisivik mines and the communities, where it is stored in tankage to meet the year-round needs. Communities in the Kitikmeot region and along the Mackenzie Valley north of Fort Norman obtain their fuels from the refinery at Norman Wells, which currently produces Turbo B fuel, P50, P40, HFO and residual fuel oil.

Product in the Yellowknife area generally comes from Edmonton via rail to Hay River and then by barge or tanker truck to Yellowknife. The Lupin mine trucks its Edmonton produced fuel in over a winter road from Yellowknife.



Northwest Territories Supply Regions
Figure 6

One option is to continue to supply the communities and existing and future mines from present day sources. However, when one considers that the Norman Wells refinery can produce only about 75,000 m' of diesel a year, it is evident that any increase in demand would have to be met from southern refineries, or offshore, thus incurring the large transportation charges.

Hydroelectric Power

One option currently under consideration is to develop hydroelectric power from a number of possible locations in the Coppermine River basin. One site is at Rocky Defile. This location has the potential to produce approximately 68 MW (397 gWh), which could be distributed by power line to the mine sites. This facility and distribution system would cost an estimated $220 million. Other less expensive hydroelectric options are also under consideration, however, production from them may be limited due to the seasonal flow characteristics of the rivers.

Back haul from Europe or Southern Canada

The developers of the proposed Izok Lake mine are considering moving the metal concentrate during the winter months to a deep water port near Coppermine, where it would be stockpiled. The ore would be shipped during the summer months or over an extended navigation season, in ice-strengthened ore carriers through the southern route of the Northwest Passage to European markets. A portion of the concentrate could also be shipped west to markets in the Pacific Rim. These ore carriers can be upgraded (at a capital cost of about 5 to 10 M$ depending on the size and class of the ship)' to allow them to carry both concentrate and fuel, thus providing for the possibility of back hauling diesel at low cost from offshore sources. The diesel would be stored at a Coronation Gulf deep water port and then moved by truck or pipeline to the mine sites. Surplus diesel above mining needs could also be barged to the communities in the area, reducing the transportation costs of moving product from Norman Wells.

Developing Local Hydrocarbon Resources

The final supply option considered in this study is the development of some of the discovered oil reserves in the area, to provide a feed stock for a northern topping plant. Diesel (and potentially other products) would be barged or shipped from the plant to the deep water port in the Coronation Gulf and the communities. From the port, the fuel would be trucked or pipelined to the mine sites.

The development alternatives considered for this study are:

- The development of small onshore reserves that would be produced year round to supply a nearby topping plant. Product from the topping plant would be stored and then transported during the summer months to the communities and mine sites.
- The development of an offshore oil reservoir for production during the summer. Some production would be transported to southern markets, while the rest would be used as feed stock for a northern topping plant.
- The installation of a topping plant at Bent Horn to produce diesel to be shipped south during the summer to the Coronation Gulf. From there, it would be trucked to the mines, or barged to the communities.

Another possibility would be to develop local gas reserves and either liquefy the gas or build a small pipeline to the mine sites. However, the author judges this alternative to be relatively expensive, and unable to compete with the oil alternatives. It was therefore not considered in this study.

Hydrocarbon Development

Local Alternatives

As already noted, exploration for oil and gas in the Northwest Territories dates back to the early 1920s. While a number of significant discoveries have been made, production to date includes only the Norman Wells field in the southern area of the region and a small seasonal production operation at Bent Horn in the Arctic Islands. The primary reason for this lack of development is that high-cost transportation systems are required to move the product to southern markets.

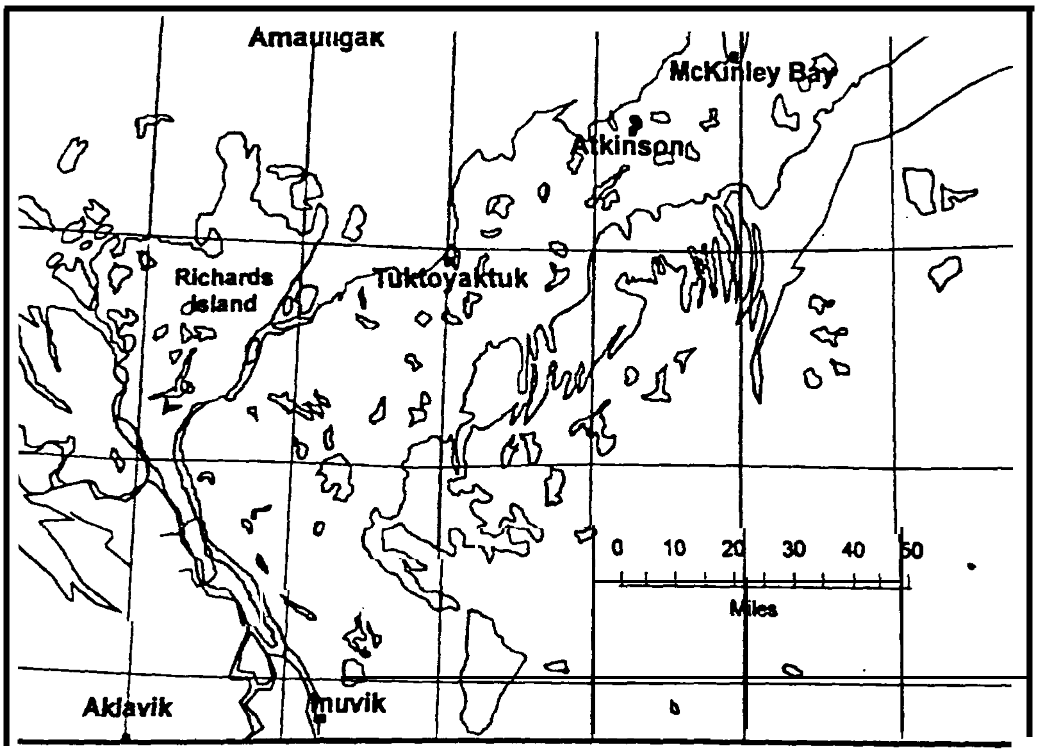
The hydrocarbon development alternatives considered for this study include one of the smaller onshore pools in the Mackenzie Delta, one of the offshore fields in the Beaufort Sea, and existing production from the High Arctic. Three fields have been selected from the present day reserve base in the area to exemplify these alternatives. They are the Atkinson oil field discovered in 1989, which is located on the Tuk Peninsula, the Amauligak oil and gas field discovered in the offshore area in 1985, and the Bent Horn field currently on production in the high Arctic.

The two Beaufort fields were selected for a number of reasons. The Amauligak field was chosen because seasonal production from the reservoir has been considered in the past and because of its potential for full-scale development- The Atkinson field was selected because its reservoir and production characteristics are such that development costs are relatively low compared to other onshore reservoirs, and because of its proximity to ports at Tuktoyaktuk and McKinley Bay. The Bent Horn field in the Arctic Islands was chosen mainly because it is currently on production and because it is near Resolute and the Polaris and Nanisivik mines.

Development Plans & Costs

Atkinson

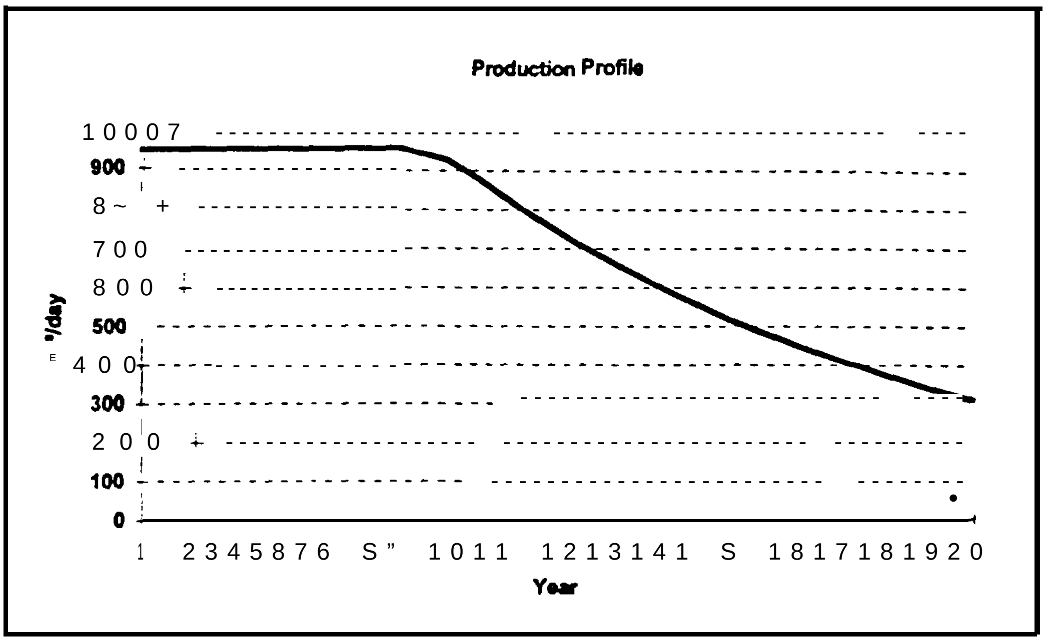
The Atkinson reservoir is a lower Cretaceus sandstone located in the heavily faulted region of the Tuktoyaktuk Peninsula (Figure 7). The reservoir covers an area of five sq. kilometers and has recoverable reserves of approximately four to six million m^{35}.



Mackenzie Delta / Beaufort Sea
Figure 7

The scope of the field development and the associated capital investment were established using the Northern Regions Venture Cost model (NORCOST©) developed by NORTH OF 60 ENGINEERING LTD.

The field could be produced at a rate of approximately 950 m^3/day for a period of about eight years before natural decline occurs. A production profile is shown in Figure 8. Five production wells and two water injectors would be required to recover the oil in the reservoir. These wells would be drilled from three locations within the field. An above ground gathering system would gather the production from the well heads to the central production facilities, which would separate the oil, gas and water. The separated water would be re-injected into the reservoir to maintain reservoir pressure, while the small amount of produced gas would be used for fuel. The oil would then be pumped some 30 km through an above-ground pipeline to a topping plant, which, for this study, is assumed to be located at either McKinley Bay or near Tuktoyaktuk. These locations were selected because they are close to Atkinson, and because they provide access to vessels with relatively large drafts.



Atkinson Production Profile (m³/day) Source: N60 Eng.
Figure 8

A number of additional facilities would be required to support the operation. hey include housing, water and sewage" treatment facilities, power generation and support utilities. A small amount of production storage has also been included in the estimate.

Total field development costs are estimated to be $76.9 Million (1993). A breakdown of the cost is shown in Table 6.

Component	Cost M$(1993)
Drilling	21.02
Flowlines	1.29
Interfield Gathering Lines	2.56
Plant Facilities	20.72
Offsites	17.95
Trunkline	13.39
Total	$76.93

Atkinson Cost Summary Source: N60 Eng.
Table 6

Amauligak

The second alternative that has been considered in the past is to produce some of the large offshore reserves on a seasonal basis, using existing exploration platforms such as the Molikpaq. This structure can be easily modified to accommodate 15 wells and production facilities to process more than 4,000 m^3/day. An allowance has been provided in the estimate should ice reinforcement to the structure be needed.

The Amauligak reservoir has been selected as an example for the purposes of this study. The reservoir, located in 20m of water, was discovered in 1985. A field of this size could easily produce 4000m^3/day over a 90-day production season (1,000 m^3/day average for the year). NORTH OF 60 ENGINEERING LTD. has assumed that five producers and two injectors would be required for seasonal production, based on quoted production tests[6] for the reservoir. The production facilities would be similar to those onshore. The crude could be barged or shipped to a topping plant onshore, or refined directly on the platform or a floating storage vessel. An onshore plant would require 275 days of storage, while a platform plant would require a topping plant with a design capacity of 4000 m^3/day. Offshore refining has been assumed for this study, because the incremental costs for a larger topping plant are likely to be lower than the estimated cost of 25M$ for the 275,000 m^3 of required crude storage.

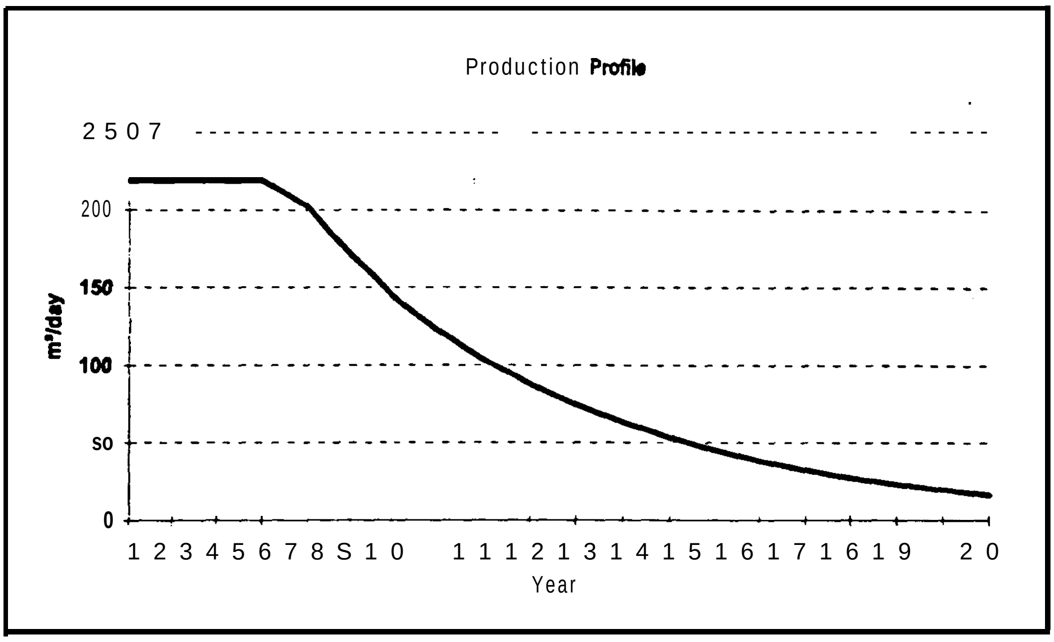
The development costs associated with this alternative are summarized in Table 7. They are approximately 50M$ more than the onshore alternative, however, the higher costs are offset to some degree by lower product storage costs.

Component	Cost M$(1993)
Drilling	70.
Offshore Berm	10.
Platform Upgrades	45.
Total	$125.

Offshore Cost Summary Source: Gulf Canada
Table 7

Bent Horn

The final supply source considered for this study is Panarctic Oil Ltd."s small Bent Horn Field on Cameron Island. The Bent Horn field has been produced on a seasonal basis since 1985. The production is transported by a ice strengthened tanker (two to three trips per year) to southern refineries. Bent Horn has estimated remaining reserves of less than 800,000 m'. It would therefore have limited ability to meet the long-term demand presented earlier in this report, although, it could supply the nearby mines of Polaris and Nanisivik and the community of Resolute. The field could continue to produce at current rates for a number of years. (Figure 9). and if a small topping plant were installed, the diesel yield would be about 30,000 m' per year.

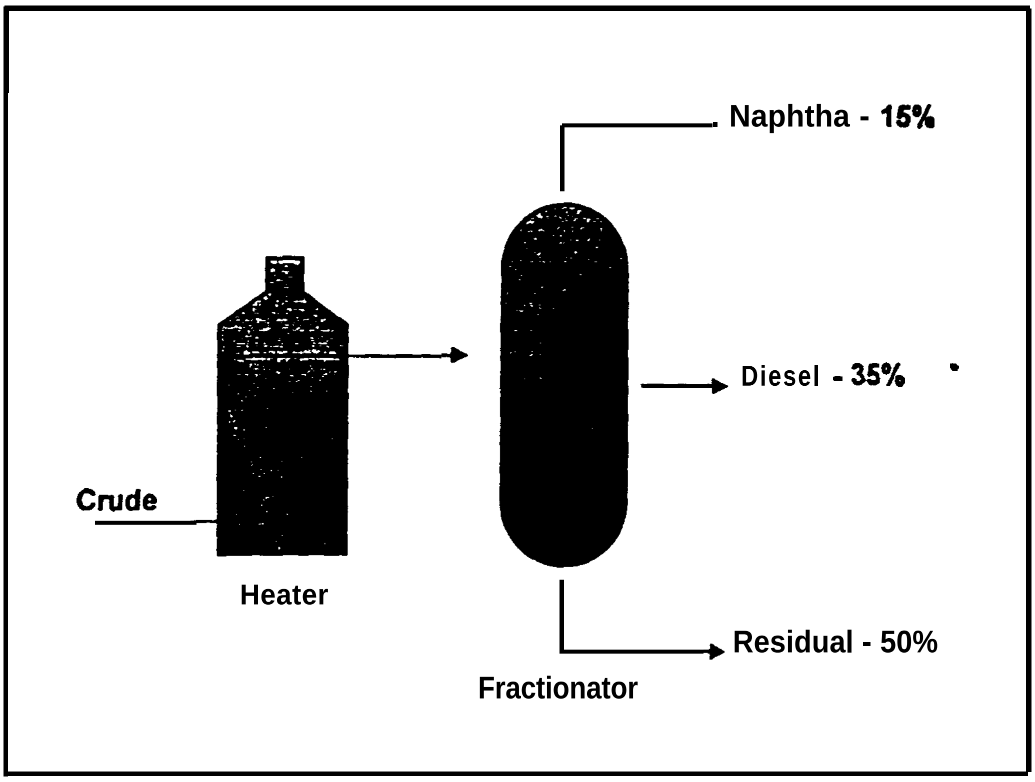


Bent Horn Production Profile Source: N60 Eng.
Figure 9

The nearby Cisco field has much larger reserves in the order of 30 to 50 million m^3; however, they would be difficult and costly to produce, given that they are offshore in 300 metres of water. It is not likely they would be able to compete with the other options.

Topping Plant

A northern topping plant located in the McKinley Bay / Tuktoyaktuk area, or at Bent Horn would process the crude from the above development alternatives to produce distillate. For this study, it has been assumed that the topping plant would be designed to maximize diesel production. It would, therefore, produce three products, light ends (naphtha), diesel, and heavy ends, commonly referred to as residual. The products and assumed yields are summarized in Figure 10.



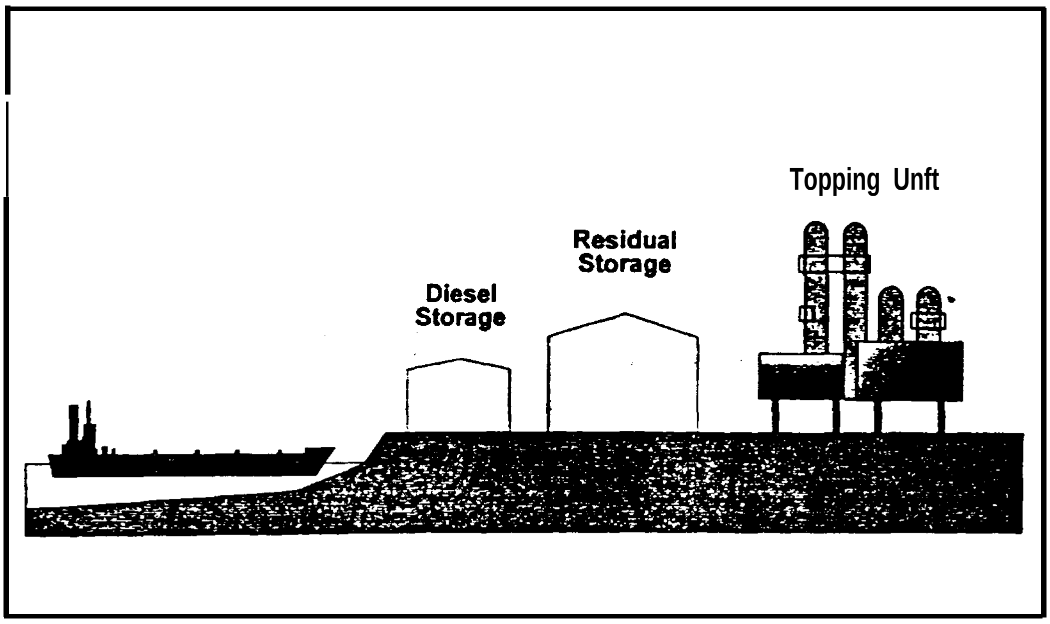
Topping Plant Schematic & Yields
Figure 10

The product yields are very dependent on crude composition, however, the values shown in Figure 10 are representative. It has also been assumed that the produced naphtha would be sold and used for local power generation, while the residual would be either re-injected or shipped to southern markets.

Specific details for each of the supply alternatives are discussed in the following sections.

Atkinson

The topping plant for the Atkinson supply alternative is assumed to be located at McKinley Bay or near Tuktoyaktuk, because either of these locations provides access for deep draft vessels. The plant would be located onshore and would operate year round. Tankage would provide 270 days of storage for the diesel and the residual and 90 days of storage for the naphtha. A schematic of the key topping plant parameters is presented in Figure 11.



Atkinson Topping Plant
Figure 11

The 125,000 m' of diesel produced annually would be transported during the summer months by ship to the Coronation Gulf, and by barge to the communities. The specifics of the transportation system are discussed in greater detail in the supply cost section of this report. The residual could either be sold locally, r-injected into a suitable reservoir (which would eliminate the need for tankage), barged to Norman Wells, where it would be pumped into the Norman Wells pipeline, or transported by ship around Alaska to southern markets. The Alaska option has been assumed for this study. It is also assumed that the naphtha would be used for power generation in Tuk and Inuvik in place of the diesel and heavy fuel oil currently used.

Table 8 represents a summary of the capital costs for the topping unit, associated storage, and loading facilities.

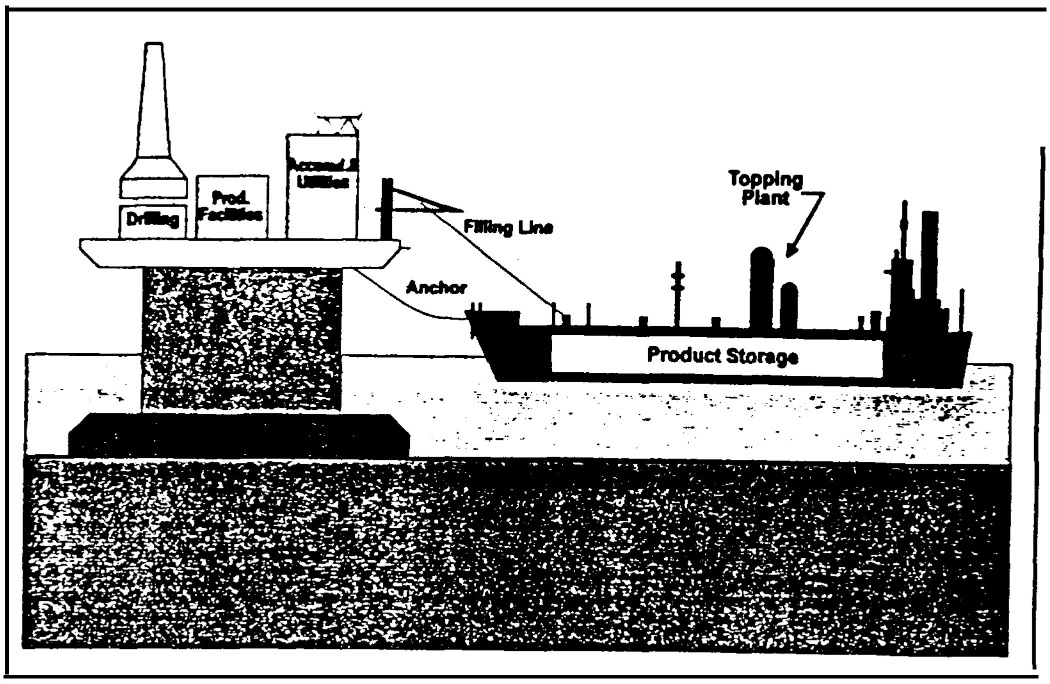
Component	Cost M$(1993)
Topping Plant	20.
Storage Costs	25.
Support facilities	10.
Total	$55.

Atkinson Topping Plant Cost Summary Source: N60 Eng.
Table 8

Amauligak

The topping plant would be located either on the production platform or on the deck of an ice reinforced storage/transportation tanker (Figure 12). The topping plant would be sized to refine all of the product during the 90 day production season. This would require a larger topping plant, but it would eliminate the need for onshore crude oil storage. The naphtha would be shuttled to Tuktoyaktuk for local power generation, the 125,000 m' diesel transported to the Coronation Gulf, again by ship, and the remaining residual shipped by barge to Norman Wells or by ship around Alaska to markets in western Canada.

The topping plant costs for this alternative are summarized in Table 9. It has been assumed that a vessel, similar to the Gulf Beaufort, (a 25,000 DWT tanker, double bottomed and ice reinforced to Class A) is used for the processing, and that it would be rented on an annual basis for 5M$/yr.



Offshore Topping Plant
Figure 12

Component	Cost M$(1993)
Topping Plant	50.
Tanker Modifications	10.
Total	$60.

Offshore Cost Summary Source: N60 Eng.
Table 9

Bent Horn Topping Unit

The Bent Horn Topping Unit would be similar to the Atkinson / McKinley Bay unit, but smaller. Based on the small reserves it has been sized to supply the community of Resolute and the Polaris and Nanisivik mines, producing 30,000 m^3 per year. The estimated capital costs are summarized in Table 10.

Component	Cost M$(1993)
Topping Plant	10.
Tankage	10.
Additional Support Facilities	3.
Total	$23.

Bent Horn Topping Unit Cost Summary Source N60 Eng.
Table 10

Economic Overview

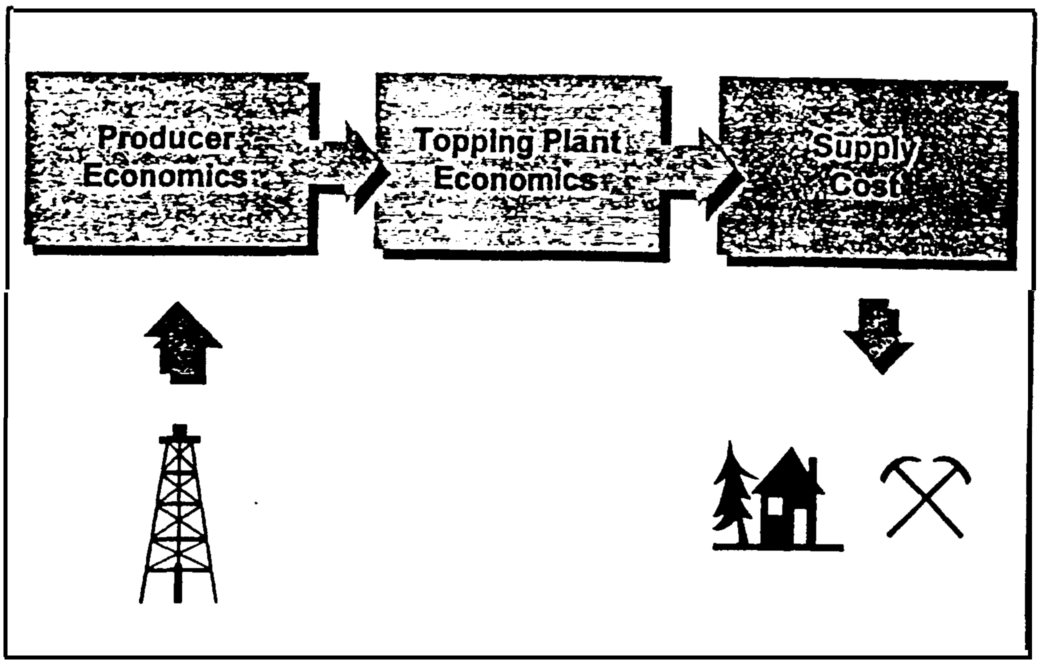
This section gives an overview of the economic model used to assess the viability of using local energy supplies as an alternative fuel source to meet community and mining needs in the region.

The model in block form is shown in Figure 13. It consists of three components:

- the producer economic model, which establishes the price of the crude, which is the feed stock to the topping plants,
- the topping plant economic model, which establishes a rack price for the diesel at the plant gate, and finally,
- a supply cost model, which incorporates the transportation costs to move the product from the topping plant to the end user.

Each of the components must be economical attractive on its own, and when they are linked together, they must be able to compete with the alternative supply options presented in the previous section of the report. The bottom line for success in a free market economy is to be able to provide energy at the lowest cost.

The following two sub-sections of the report assess the producer and topping plant economics, while the next section addresses the transportation costs and the supply cost model



Economic Model
Figure 13

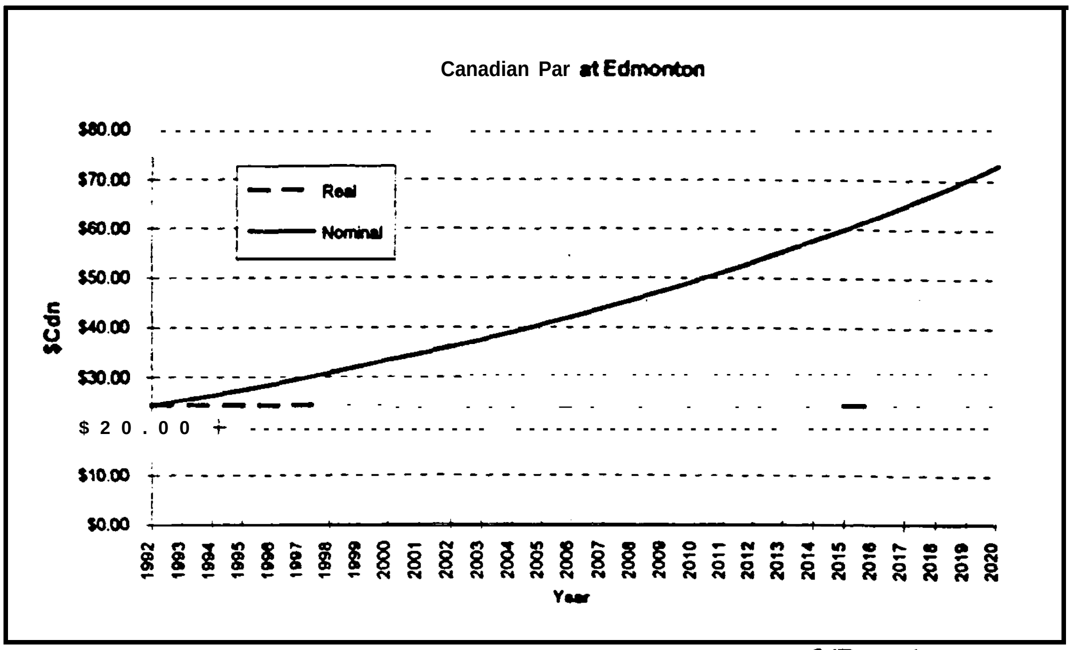
Producer Economics

The economic viability of the Atkinson and Amauligak development alternatives has been assessed using an economic model developed by NORTH OF 60 ENGINEERING LTD. The computer model calculates the rate of return on an after-tax, after-royalty basis for frontier development.

Information required to calculate the economics includes development costs, production profiles, operating costs, production price forecasts, inflation and tax rate assumptions.

Capital costs and production profiles for each development alternative were summarized in the previous section.

A generic and relatively conservative price forecast was used in the analysis. It is based on a $20 US/barrel ($125.78/m3) flat (in constant 1993 dollars) price forecast for West Texas Intermediate Oil in the Chicago market place. The corresponding Edmonton price forecast is shown in Figure 14.

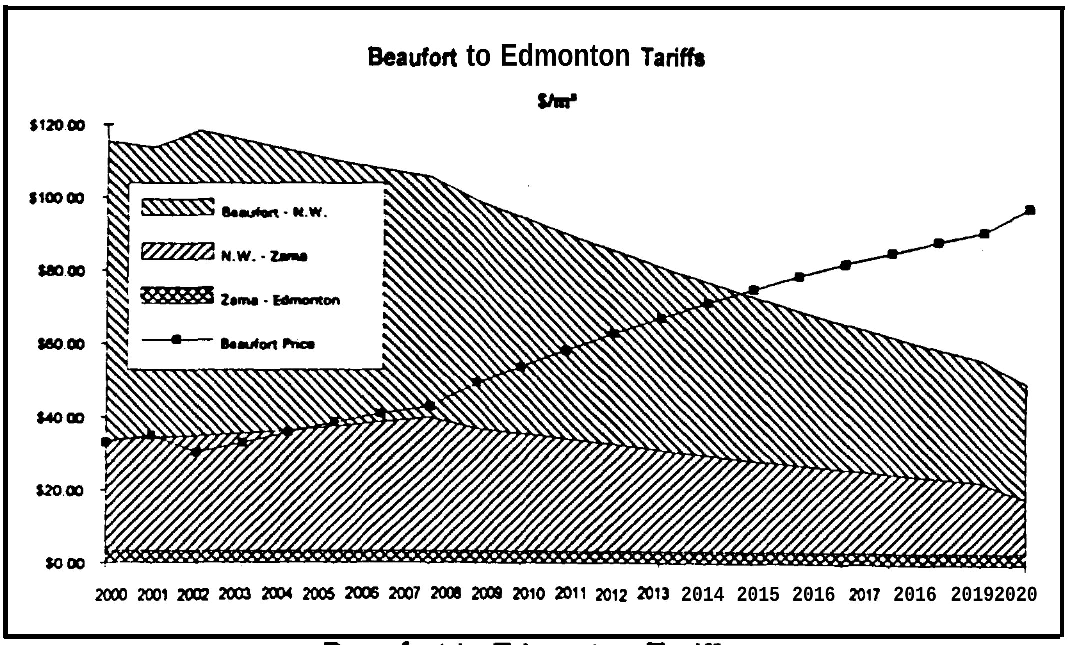


Oil Price Forecast - Canadian Par at Edmonton $/Barrel
Figure 14

Three different economic cases were considered. They were:

1. A fieldgate price equal to the Edmonton price less a transportation tariffto move the product from each location to Edmonton.
2. A fieldgate price equal to the Edmonton price with no transportation tariff.
3. A fieldgate price calculated to yield a15percentretum on an after tax after royalty basis.

The transportation costs used inthe first economic case are based onan extension of the Interprovincial pipeline that currently terminates at Norman Wells. The pipeline tariffs shown in Figure 15 in constant terms are based on assumed capital costs of 600M$, an annual operating cost of 19M$ and a throughput of approximately 4,000 m^3/day. They further assume a debt equity ratio of 70/30, a return on equity of 10 per cent, a cost of capital of 10 per cent and a project life of 25 years. Both capital and operating costs are inflated at 4 per cent per annum. Tariffs are calculated in both constant and nominal dollars. The tariffs expressed in constant dollars, are an input array in the economics model to calculate the effective field price.



Beaufort to Edmonton Tariffs
Figure 15

Other financial assumptions used in the economic model include the rate of inflation, which was assumed to be 4 per cent per year and the exchange rate, which was assumed to be 0.80 $Cdn/$US. The royalties were calculated based on a CPRA royalty structure.

The results of the economic analysis are summarized in Table 11. They show that neither Atkinson nor Amauligak would be economical- on a stand-alone basis, using the calculated pipeline tariffs. Previous studies[7] have shown that Amauligak would be economical, however, if seasonal tankers were used rather than the Norman Wells pipeline extension.

The results also show that both field developments would be quite attractive if there were no transportation costs. The rates of return increase to 39 per cent and 26 per cent for Atkinson and Amauligak respectively.

The analysis also shows that the producers need a crude price of $51 .57/m³ at Atkinson and $72.95/m³ at Amauligak to realize a 15 per cent return on their investment on an after-tax after-royalty basis.

Since refining the product locally would eliminate the transportation tariffs, the oil producers could theoretically ask Edmonton prices for the crude they sell to a local topping plant. However, these high prices would make the topping plant uneconomical. The next section of this report examines the economics of refining the crude to produce diesel.

CASE		Rate of Return	NPV @ 15% M$	Required Price to Yield a 15% Return $US/m³
Atkinson	Case 1	13%	-6.0	$130.81
	Case 2	39%	56.5	$51.57
	Case 3	15%	0.0	$51.57
Amauligak	Case 1	8%	-30.0	$149.67
	Case 2	26%	46.8	$72.95
	Case 3	15%	0.0	$72.95

Summary of Producer Economics
Table 11

Topping Plant Economics

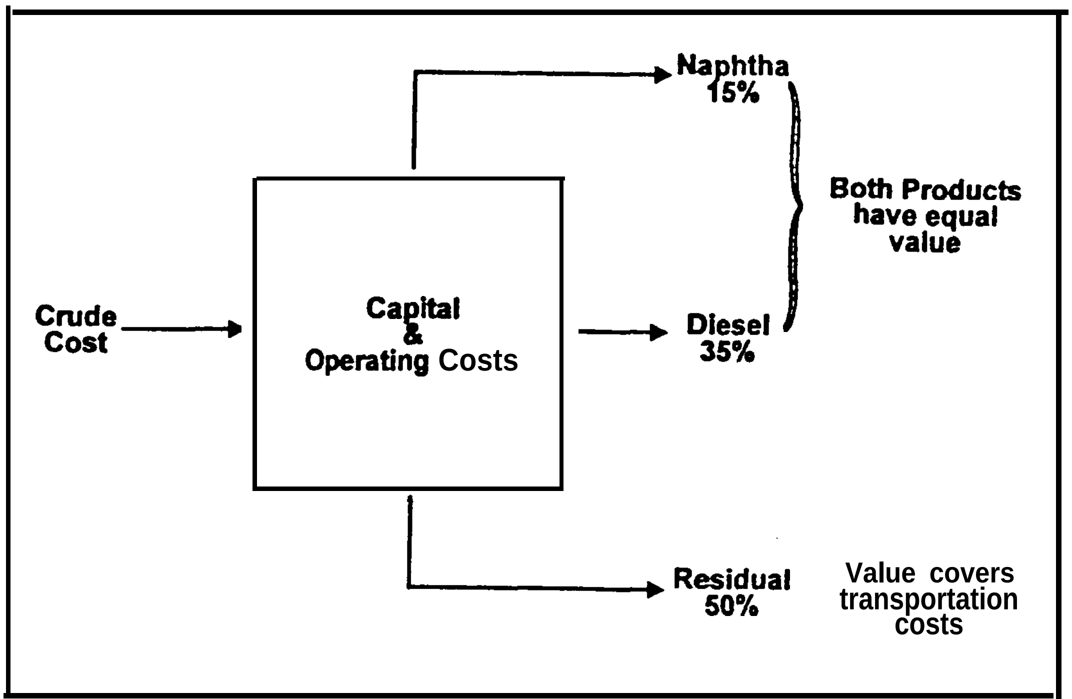
The economic model for the three topping plants is shown in Figure 16. It is assumed that the topping plant is treated as an independent processing facility. The owners would purchase the crude from the producers at a fair market value. For this study, that value is assumed to be the crude price which yields the producers a 15 per cent rate of return on an after-tax after-royalty basis.

It has been further assumed that the topping plant produces two products of value, the naphtha and the diesel, and that both are of equal value. While capital and operating costs are included to store the residual, it is assumed that the transportation costs to move it to southern markets offset its value.

A 15 per cent return on an after-tax basis has been assumed in calculating the rack price for the diesel and the naphtha.

The key economic parameters and the resulting product prices for the three alternative topping plants are summarized in Table 12.

Table 12 shows that the onshore topping plant at McKinley Bay results in the lowest rack price of $213.57/m3. Product from the offshore topping plant is more expensive at $270.95/m³ while Bent Horn product is considerably more expensive at $392.09/m³. This high cost can be attributed to two factors: the cost of crude, which has been assumed to be priced at Edmonton par, less an estimated tariff of $38/m³ (to move the product from Bent Horn to Montreal) and the low throughput, which results in a relatively high capital cost per unit volume.



Topping Plant Economic Model
Figure 16

Topping Plant	Capital Cost M$	Operating Cost M$/yr.	Crude Price $US/m³	P50 & Naphtha Price $Cdn/m³
Beaufort Onshore	55	5.4a	51.57	213.57
Beaufort Offshore	60	5.46	72.95	270.95
Bent Horn	23	1.26	115.52	392.09

Topping Plant Economic Parameters
Table 12

Supply Cost Analysis

Supply Cost Model

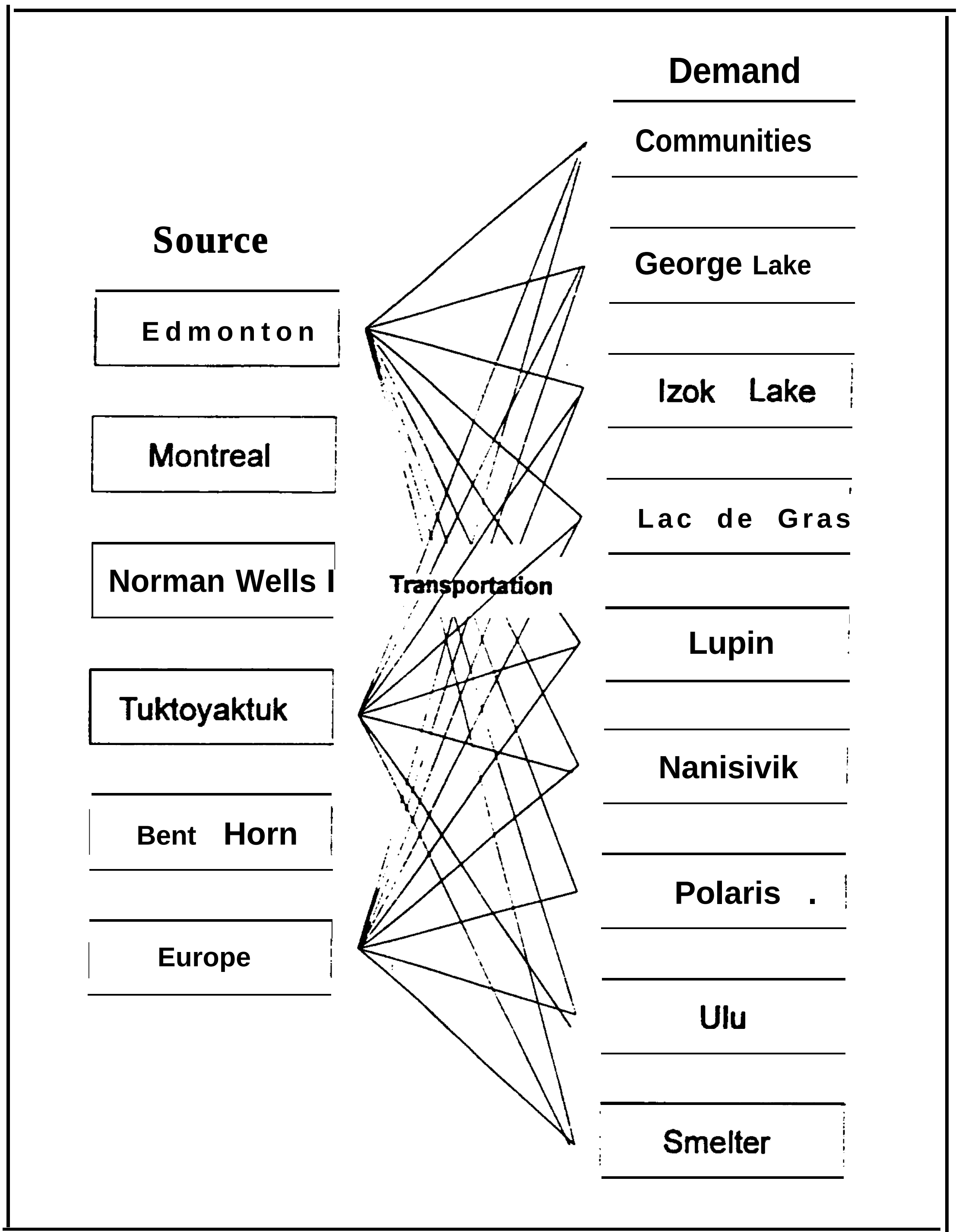
The viability of utilizing northern reservoirs as an energy supply for the mining industry and local communities depends on the ultimate supply cost of the product.

As outlined earlier in the report, there are" a number of supply options. They include existing sources at Edmonton, Norman Wells and Montreal, and possible attematives such as back hauling from Europe or a new topping plant in the McKinley Bay / Tuktoyaktuk area or at Bent Horn, Each source has an inherent product cost and a cost to transport the product to the end user.

As part of this study, NORTH OF 60 ENGINEERING LTD. has developed a supply cost model to determine the most economic means of supplying product for any given demand scenario. Figure 17 is a simple representation of the model, which was written to run under Microsoft Excel Version 4.0.

The worksheet model determines the minimum supply cost from each source to meet the demand, while not exceeding the capacity of each source.

The key variables in the model are product price and transportation costs.



Supply Cost Model
Figure 17

Product Prices

Product prices are summarized in Table 13. The Edmonton and Norman Wells numbers are based on data supplied by the Petroleum Products Division of the GNWT Department of Public Works and Services.

Product prices from potential topping plants at Tuktoyaktuk / McKinley Bay and Bent Horn were derived in an earlier section of the report. They are based on yielding the developer of these facilities a 15 per cent rate of return.

Rack prices for Montreal and Europe are based on the assumption that refineries in Montreal and Europe are as efficient as Edmonton and that they would compete. The rack prices at Montreal and Europe have, therefore, been assumed to be equal to $200/m³. In the end analysis, the European price is an important assumption, but one that appears to be reasonable, based on a recent comparison of posted prices.

Product Source	P50 Rack Price $/m*
Edmonton	$198.
Norman Wells	$290.
Montreal	$200.
Europe	$200.
Tuktoyaktuk	$213.
Bent Horn	$392.

P50 Rack Price $/m'
Table 13

Transportation Analysis

This section analyzes the options and costs of transporting petroleum products to potential mine sites and communities within the NWT. The four transportation alternatives considered were:

1. For current supply sources, the present day tug and fuel barge system.
2. For a topping plant at Bent Horn, product would be shipped to the Coronation Gulf by the M.V. Arctic or a similar high ice class tanker. Distribution to local communities would be by tug and barge from a deep water port in the Gulf.

3. For a topping plant at or near Tuktoyaktuk or McKinley Bay, product would be shipped to the Coronation Gutf deep water port and communities along the coast by an ocean-going barge similar to the ATL's Arctic Kiggiak. Distribution to inland communities would be by the current tug and fuel barge system.
4. Back haul of product from Europe to the Coronation Gulf using OBO carriers or ice breaking tankers. Distribution to local communities would be by tug and barge from the Coronation Gulf deep water port.

Transit Analysis

A detailed transit analysis is presented in Appendix B. This includes distances, regulatory access, ship data, a review of ice conditions and a calculation of transit times.

The analysis suggests an M.V. Arctic type of vessel would, on average, take nine or ten days for a round trip from Bent Horn to the Coronation Gulf. This would allow three trips per season transporting, on average, 70,000 m^3/year.

The transit times from the Mackenzie Delta to the Coronation Gulf are dependent on the type of vessel used to transport the diesel. It is estimated that ten trips could be reliably made during the 90 days open water season.

Transportation Unit Costs

Status Quo - Tug and Barge / Ship

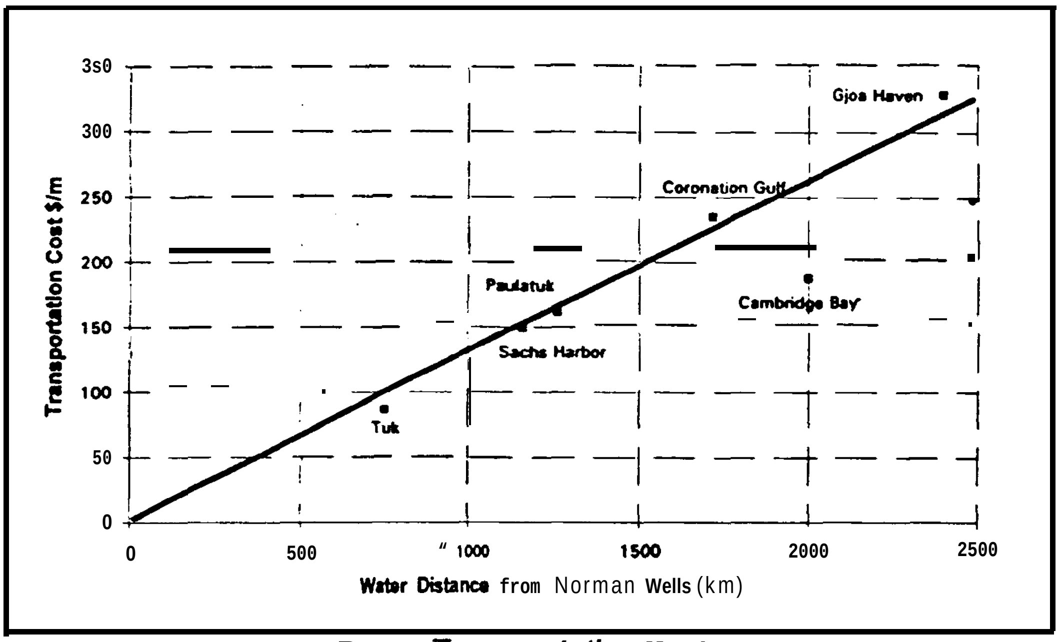
The current cost of moving product to a number of the communities within the NWT has been supplied by GNWT and is shown in Table 14. The freight costs for each location, with the exception of Resolute, are plotted in Figure 18 as a function of distance from the supply source, Norman Wells. It can be seen that the unit transportation cost for barges can be approximated by $13.75 /$m^3$/100km.

The shipping cost for Resolute is based on a quoted rate of $100.90 /m' from the GNWT Department of Transportation. This represents the average shipping cost from East Cost refineries to Eastern communities in the NWT.

Transportation costs from present day sources to the communities and mines considered in this study are shown in Table 15. A Coronation Gulf deep water port would be used as a terminal for the mines, because it is common to all the transportation alternatives considered. The cost figures for the western communities and mines are based on the barge rate of $13.75 /m³/100km, while the costs for Resolute, Nanisivik and Polaris use the rate of $100.90 mentioned on the previous page.

Community	Transportation Mode	Transportation Cost $/m³
Cambridge Bay	Barge & Tug	$187.90
Coppermine	Barge & Tug	$235.00
Gjoa Haven	Barge & Tug	$329.70
Paulatuk	Barge & Tug	$161.50
Resolute	Ship	$100.90
Sachs Harbor	Barge & Tug	$149.10
Tuktoyaktuk	Barge & Tug	$86.50

Actual Product Transportation Costs Source: EMPR
Table 14



Barge Transportation Costs
Figure 18

Supply from Conventional Sources Edmonton, Norman Wells, E. Coast				
Community / Industry	**River Distance km**	**Ocean Distance km**	**Total Distance km**	**Calculated Cost $/m³**
Aklavik	600		600	104.50
Cambridge Bay	760	1240	2000	275.00
Coppermine	760	960	1720	236.00
Coronation Gulf	760	960	1720	236.00
Gjoa Haven	760	1640	2400	330.00
Holman Island	760	600	1360	187.00
Inuvik	600		600	82.50
Paulatuk	760	500	1260	173.00
Resolute				100.90
Sachs Harbor	760	400	960	132.00
Taloyoak	760	1840	2600	357.00
Tuktoyaktuk	760		760	104.50
Nanisivik				100.90
Polaris				100.90

Note Resolute, Polaris & Nanisivik currently supplied from East Coast

Transportation Costs from Existing Supplies
Table 15

Bent Horn to Coronation Gulf - M.V. Arctic

This section summarizes the transportation costs from Bent Horn to the communities and mines using a combination of ice reinforced ship similar the M.V. Arctic and conventional tug and barges.

Rates for the M.V. Arctic are dependent on many factors, and therefore, the Canarctic Shipping Company Limited, owner/operator of the vessel, was reluctant to release rates for the purposes of this study.

The daily charter rate that has been assumed for this type of vessel in this study is $30,000/day plus fuel, which is believed to be realistic. Total daily cost would be about $35,000/day using marine diesel, or $40,000/day, if P-50 fuel value were used. Capacity of the M.V. Arctic is approximatety 20,000 m'.

Mobilization costs must be included if the M.V. Arctic or similar vessel were to operate seasonally in the Arctic. These could often be defrayed by transporting fuel north. But, to be conservative, it is assumed that ship costs for travel to and from the Arctic are fully included in mobilization. Using a $35,000/day charter cost, and a 14 day transit time (one way), the total mobilization and demobilization cost is about $1.0 million.

From the transit analysis, it has been assumed that three round trips could be made in the 40-day season. In three trips, the M.V. Arctic could deliver 60,000 m^3 of product. Each round trip is assumed to take ten sailing and three loading/unloading days.

Mobilization and demobilization costs are allocated over the three trips - $333,000 per trip. The cost per trip is $820,000 (10 x 40,000 + 3 x 30,000 + 333,000). The unit transportation cost is therefore $41/m³.

From the Coronation Gulf, product could be barged to local communities, using the barge cost of $13.75 /m³/1 00km discussed earlier.

Table 16 has been prepared using the above costs. As can be seen. barge costs dominate the total cost of supplying the communities: Transportation costs for Resolute, Nanisivik and Polaris are based on direct shipment, using M.V. Arctic costs.

Topping Plant at Bent Horn					
Community / Industry	Ship Distance km	Ship Cost $/m'	Barge Distance km	Barge Cost $/m³	Total Trans. Cost $/m³
Aklavik	1550	41.00	1120	154.00	195.00
Cambridge Bay	1550	41.00	440	60.50	101.50
Copperrnine	1550	41.00	0	0.00	41.00
Coronation Gulf	1550	41.00	0	0.00	41.00
Gjoa Haven	1550	41.00	840	115.50	156.50
Holman Island	1550	41.00	440	60.50	101.50
Inuvik	1550	41.00	1120	1 Moo	195.00
Paulatuk	1550	41.00	640	88.00	129.00
Resolute	500	8.00	0	0.00	8.00
Sachs Harbor	1550	41.00	720	99.00	140.00
Taloyoak	1550	41.00	880	121.00	162.00
Tuktoyaktuk	1550	41.00	960	132.00	173.00
Nanisivik	1000	16.00	0	0.00	16.00
Polaris	500	8.00	0	0.00	8.00

Transportation Costs from Bent Horn
Table 16

Tuk/McKinley Bay to the Coronation Gulf- Ocean Barge

An ocean going barge has been assumed to move the diesel from a topping plant located at McKinley Bay, or near Tuktoyaktuk.

The transit analysis indicates that each round trip will require about six days of sailing and two days for loading/unloading. A total of 12 trips is therefore possible during the 90 day open water season. A barge similar to the ATL's Arctic Kiggiak, with a capacity of 12,500 m' would be required, assuming 10 trips per year.

Transportation costs have been calculated based on a capital cost of 7.5 million dollars and annual operating costs of $1.55 million for maintenance, tug rental and fuel. The average he-year tariff is calculated to be $17.80 /m'.

Transportation costs from Tuktoyaktuk to the communities along the coast are prorated based on the distance from Tuk. Transportation to inland communities along the Mackenzie River is based on river barge costs. It is not economically feasible to transport product to Resolute, Nanisivik and Polaris with this transportation system. An alternative such as the M.V. Arctic would have to be used. These locations could also be supplied from another source

Transportation costs for the ocean barge option are shown in Table 17.

Topping Plant Tuk/McKinley Bay Area					
Community/ Industry	Ocean Distance km	Ocean cost $/m³	River Distance km	Barge cost $/m³	Cost $/m³
Aklavik		0.00	160	22.00	22.00
Cambridge Bay	1400	25.96			25.96
Coppermine	960	17.80			17.80
Coronation Gulf	960	17.80			17.80
Gjoa Haven	1800	33.38			33.38
Holman Island	600	11.13			11.13
Inuvik			160	22.00	22.00
Paulatuk	500	9.27			9.27
Resolute					
Sachs Harbor	400	7.42			7.42
Taloyoak	1840	16.32			16.32
Tuktoyaktuk	0	0.00			0.00
Nanisivik					
Polaris					

Transportation Costs from Tuktoyaktuk
Table 17

Back Haul of Product from Europe

This case represents the competition to local supply. The costs to back haul refined product from Europe have been calculated on an incremental basis. They represent the direct costs that need to be recovered by the ship operator. Clearly, the operator would be in a strong position to adjust rates above this to maximize profit, as long as the costs were below local supply options.

This analysis is based on using one 40,000 DWT CAC 2 carrier as proposed in a recent Canarctic Study that assessed the feasibility of transporting minerals from the Coronation Gulf area. This carrier could be modified at a 10 percent increase in capital cost, to an OBO (combination carrier) to cany about 50,000 m^3 of product. The incremental capital cost is estimated to be about $12.8 million Cdn including a 10 per cent contingency.

From the Canarctic study, the all-inclusive daily rate was estimated to be about $55,000/day. The incremental operating cost to carry product would be the time to pick Up and off load the product and to clean the storage tanks to allow the ship to carry bulk mineral concentrates. These operations are assumed to add six days to each trip. Thus, the incremental operating costs based on three trips per year is approximately $1.1 million (3 trips x 6 days x $55,000/day x 1.10) including contingency.

A tariff has been calculated based on the initial $12.8 million capital investment and annual operating costs of $1.1 million to move 150 x 10^3m^3 per year. it is a relatively low cost of $15.72 /m'.

Table 18 shows delivery costs based on back haul and local barging.

Back Haul from Europe to the Coronation Gulf				
Community I Industry	Ship Cost $/m³	Barge Distance km	Barge Cost $/m³	Total $/m'
Aklavik	15.72	1120	154.00	169.72
Cambridge Bay	15.72	440	60.50	76.22
Coppermine	15.72			15.72
Coronation Gulf	15.72			15.72
Gjoa Haven	15.72	840	115.50	131.22
Holman Island	15.72	440	60.50	76.22
Inuvik	15.72	1120	154.00	169.72
Paulatuk	15.72	640	88.00	103.72
Resolute	15.72			15.72
Sachs Harbor	15.72	720	99.00	114.72
Taloyoak	15.72	880	121.00	136.72
Tuktoyaktuk	15.72	960	132.00	147.72
Nanisivik	15.72			1572
Polaris	15.72			15.72

Transportation Costs from Europe
Table 18

Transportation Cost Summary

The transportation costs from the various supply sources to the communities and mines are summarized in Table 19. Transportation costs from the Coronation Gulf deep water port to the mine sites have not been included in the analysis because they are common to all options except for delivery from Edmonton. It has been assumed that if product were delivered from Edmonton, it would be transported by train to Hay River, then by barge to Yellowknife, and then by truck over winter roads from Yellowknife to the mine sites. The mining transportation costs shown in the Edmonton column reflect the cost to move the product to Yellowknife. It is assumed that the trucking costs from Yellowknife to the mine site would be similar to the trucking costs from the Coronation Gulf, and, therefore, they are not included, in order to be consistent.

Clearly, the transportation costs from Europe and Tuktoyaktuk are significantly lower than current practices. A careful examination of the numbers shows back hauling product from Europe to Coronation Gulf to be slightly cheaper than transporting product from the Tuktoyaktuk area.

Supply Location						
Community/ Industry	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik	$195.00	$189.20	S169.72		$80.00	$22.00
Cambridge Bay	$101.50	$297.10	$76.22		$187.90	$25.96
Coppermine	$41.00	$344.20	S15.72		S235.00	$17.80
Gjoa Haven	$156.00	S438.90	S131.22		S329.70	$33.38
Holman Island	S101.50	$296.20	S76.22		S187.00	$11.13
Inuvik	$195.00	$189.20	S169.72		S80.00	$22.00
Paulatuk	S129.00	$270.70	S103.72		S161.50	S9.27
Resolute	$8.00		S15.72	$100.90		
Sachs Harbor	$140.00	$258.30	S114.72		S149.10	S7.42
Taloyoak	$162.00	$466.70	S136.72		$357.50	S16.32
Tuktoyaktuk	$173.00	$195.70	S147.72		$86.50	$0.00
George Lake	$41.00	$60.00	S15.72		$235.00	$17.80
Izok Lake	$41.00	S60.00	S15.72		$235.00	.%17.80
Lac de Gras	$41.00	$60.00	S15.72		$235.00	$17.80
Lupin	$41.00	$60.00	S15.72		$235.00	S17.80
Nanisivik	S16.00		S15.72	S100.90		
Polaris	$8.00		S15.72	$100.90		
Smelter	$41.00	$344.20	S15.72		$235.00	S17.80
Ulu	$41.00	$60.00	S15.72		$235.00	$17.80
Petroleum	$173.00	$195.70	S147.72		$86.50	'$0.00

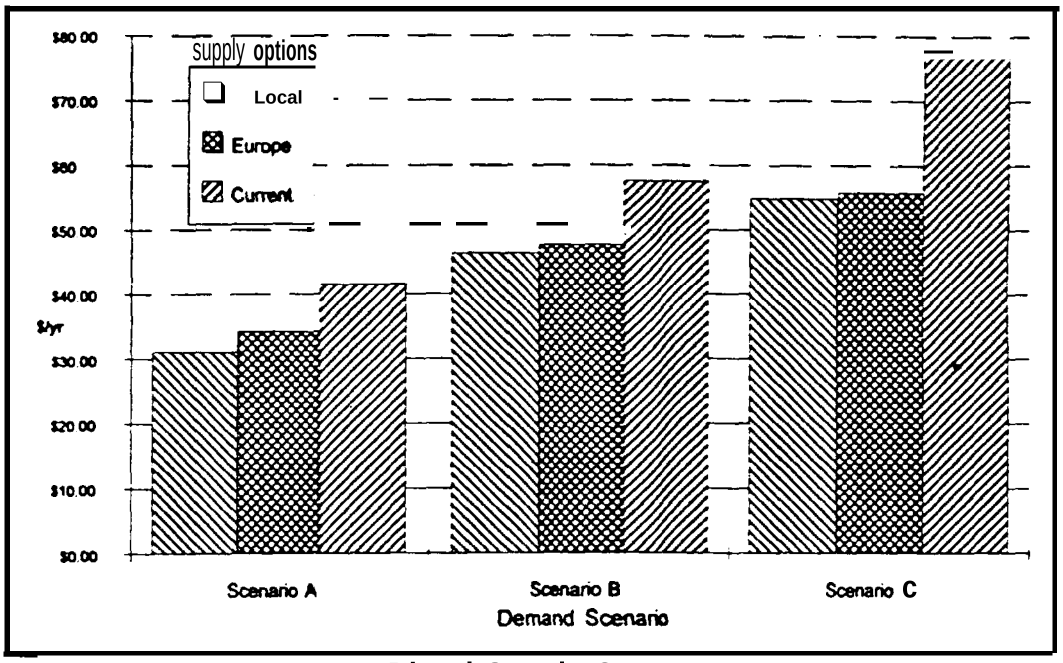
Transportation Cost Summary $/m'
Table 19

Supply cost for Demand Scenarios

The transportation costs in Table 19 were combined with product prices (Table 13) and the demand volumes for each of the three scenarios that were presented at the beginning of the report. The model was then run to determine the optimum supply cost for three different supply options. They were:

- current supply sources, i.e. Montreal, Edmonton and Norman Wells
- current supply sources, plus local topping plants at Tuk and Bent Horn
- current supply sources, plus Europe.

The results of the analysis are summarized in Figure 19 and Table 20. A summary of each case is presented in Appendix C of the report.



Diesel Supply Cost
Figure 19

From a cost standpoint the results show that local energy supplies yield the lowest supply cost for all three scenarios. Back hauling from Europe is a close second while utilizing current sources is clearly the most expensive.

Demand Scenario	Current	Europe	Local
Scenario A	$41.57	$34.20	$31.05
Scenario B	$57.57	$47.58	$46.28
Scenario C	$77.84	$55.79	$54.85

Diesel Supply Cost
Table 20

Europe can supply product to the Coronation Gulf slightly cheaper than a topping plant located in the Mackenzie Delta. This is evident, if for example, the community demand were dropped from Demand Scenario B. In this example, the supply cost is 27.83 M$/yr from Europe and 31.60 M$/yr using local sources. Thus, from a mining perspective, Europe is slightly more attractive.

The demand for Scenario A is slightly below the supply capability of a topping plant in the Mackenzie Delta, and, therefore, the actual supply cost for this scenario might be somewhat higher. The supply cost would still be lower than back hauling from Europe and from current sources. The lower fuel requirements would also make Europe an unlikely source of fuel.

A number of sensitivities have been considered in support of the local supply option. They are:

- the impact of a local market for the residual (HFO) valued at 25 per cent of the diesel price.
- the impact of a local market for 'the residual (HFO) valued at 50 per cent of the diesel price.
- the impact of the topping plant recovering capital and operating costs only; i.e. achieving no return on the investment.

A local topping plant would produce approximately 175,000 m^3 of heavy fuel oil per year. Some of this residual could be used for power generation and heating in Inuvik, which currently bums about 15,000 m^3 per year. Given today's technology, there is also the possibility that mines such as Izok Lake could use this fuel as an alternative to diesel for much of their energy demand. This would require separately heated storage at the mines; on the other hand, the mining industry would have an energy source that would cost anywhere from 25 per cent to 50 per cent of diesel. If for example, the mines could use HFO for 50 per cent of their energy needs, and if the rack price were 25 per cent of diesel, the total supply cost for the mines in Demand Scenario B would be inked to

23.21 M$/yr. This compares favorably to the European alternative for diesel at 27.8 M$/yr. Over the life of the mine this saving would represent a significant contribution to profitability.

The impact of potential HFO sales on the diesel rack price is shown in Table 21. Also shown in the table is the effect of operating the topping plant on a break-even perspective.

Case	Products	Naphtha & Diesel Value
Base	Naphtha & Diesel	$213.57/m³
HFO at 25% value	Naphtha & Diesel+ HFO	$200.82/m³
HFO at 50% value	Naphtha & Diesel+ HFO	$194.45/m³
Topping plant at cost	Naphtha & Diesel	$172.14/m³

Local Topping Plant Sensitivities
Table 21

The lower rack prices in Table 21 result in a lower overall supply cost for local energy. The impact of this, using Scenario B, is shown in Table 22.

Demand Scenario B	Current	Europe	Local
Base	$57.57	$47.58	$46.28
HFO at 25% value	$57.57	$47.58	$44.76
HFO at 50% value	$57.57	$47.58	$43.97
Topping plant at cost	$57.57	$47.58	$41.18

impact of Sensitivities on Diesel Supply Cost
Table 22

The final sensitivity that has been considered is the impact of no future mining development on the supply options. Under this scenario, the total diesel demand would be 112,000 m'. A somewhat smaller local topping plant in the McKinley Bay/ Tuktoyaktuk area could still produce diesel at a lower overall cost; however, it would likely displace refined product from the Norman Wells refinery, which could result in its shutdown. This would reduce some of the benefits discussed in the next section. The Norman Wells oil production that was used to feed the refinery would be shipped to southern markets.

Benefits & Spin-off Opportunities

Developing local hydrocarbon resources to supply the energy needs of local communities and mines provides a number of benefits and spin-off opportunities:

- Lower cost energy
- Employment& training opportunities
- Power generation
- Cogeneration opportunities
- Other industries that might be able to use heavy fuel oil
- Government revenue in the form of taxes and royalties

Lower Cost Energy Supply

The primary benefit of developing local resources to meet the energy needs of the communities and mines is to reduce fuel costs for the end user.

As shown in the supply section of this report, total energy costs would be reduced by anywhere from $13 million to $25 million annually. This is significant when compared to current day supply sources. The European back haul option would provide similar savings for the region; however, it would not provide the local benefits to the region.

Local Employment and Training

The development of local hydrocarbon resources would provide a number of employment opportunities both in the short term and in the long term.

Short term opportunities would be primarily associated with the field development and construction of the topping plant. While much of the production and topping plant facilities would be built in southern Canada, a number of potential business and employment opportunities exist:

- Gravel hauling and pad construction
- Erection of construction camps
- Camp maintenance and catering
- Support and direct labor for the drilling operations
- Pile installation for gathering lines and production facilities
- General labor to support construction of the gathering lines and trunkline from the field location to the topping plant
- General labor to construct the large storage tanks that would be required to store product from the topping plant
- General labor to support the construction of the fuel loading facilities

A limited number of long term employment and business opportunities would be associated with the operations of the field and topping plant

- Camp operations and catering
- Field and plant operators
- Product transfer operators (summer months only)

A number of business opportunities would be created if product were supplied from present day sources or from topping plants located in the Mackenzie Delta or at Bent Horn:

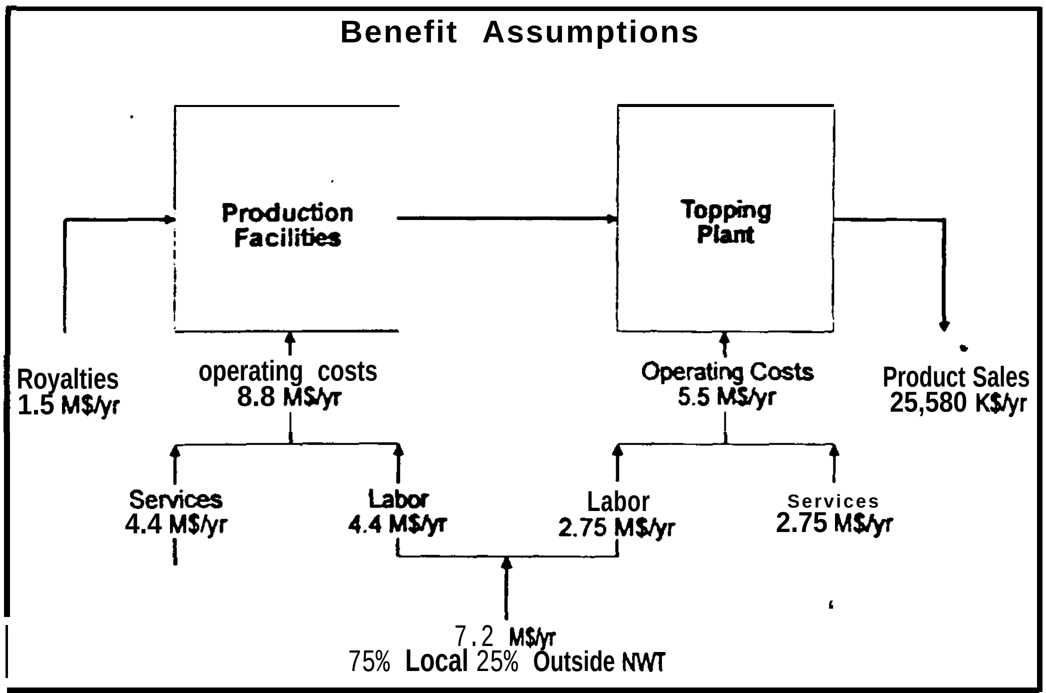
- Transportation of the topping plant products to the market place
- Trucking of fuel from the Coronation Gulf to the mine sites

With assistance from the Bureau of Statistics in the Government of the Northwest Territories, North of 60 Engineering Ltd. has attempted to quantify the direct benefits that would be associated with the construction and operation of production facilities and a topping plant located on, or near the Tuktoyaktuk peninsula. To simplify the analysis, the production facilities and the topping plant were combined. The benefits associated with transportation of the product from the topping plant to the communities and mine sites are not included in the analysis, because the trucking from the Coronation Gulf is common for all three supply options, and the barging is common to both local supply and the supply from existing sources.

As identified above, local benefits would be derived from both the construction and operating phases. The construction phase benefits, while significant, would be short-lived; unless this development were to stimulate additional exploration and development, which is a possibility,

A number of assumptions have been made to estimate local benefits. For the construction phase, it has been assumed that 40 per cent of the labor would be provided by northerners, while 60 per cent of the labor would be supplied by people living outside the Northwest Territories.

Unlike the construction benefits, the operations benefits would continue for the life of the project. A number of simplifying assumptions, which are summarized in Figure 20, have been made to quantify and assess these benefits.



Operating Benefit Assumptions
Figure 20

Benefits are derived from product sales, which in this case includes the diesel and naphtha. This revenue is derived from the capital investment of 131.9 M$, and yearly operating costs, which are assumed to be

14.3 M$/year. A further assumption in this analysis is that the operating costs are evenly divided between services and labor.

The GNWT Bureau of statistics Benefits Model was used to identify the possible benefits associated with the development of the Atkinson production facilities and topping plant, based on the above assumptions. These benefits, for both the construction and operations phases, are summarized in Table 23.

Benefits	Construction (total)		Operations / yr		Total
	Person Years	Labor Income K$	Person Years	Labor Income K$	Person Years Labor Avg./yr
Direct Labor	64	6,595	71	7,140	74
Indirect Labor	212	8,758	25	969	36
Induced Labor	80	2,000	33	819	37
Total	356	17,353	129	8,928	147

Northwest Territories Benefits
Table 23

The labor opportunities in Table 23 are subdivided into three common categories:

- Direct labor: associated with the onsite jobs.
- Indirect labor: resulting from the sale of goods and services associated with construction and operations.
- Induced labor: resulting from the spending of income associated with the direct and indirect labor.

The benefits from construction are higher than those associated with the operations, however, they are short lived in comparison. Local construction benefits, including direct, indirect and induced benefits, amount to about 32 per cent of the total construction cost.

Operations would potentially result in 129 new jobs, which would represent a before tax income of $8.93 million per year.

In addition, the employment and business opportunities associated with construction and operations would provide valuable training and experience, which could be applied to larger-scale hydrocarbon developments that would be likely to occur in the future.

Electrical Power Generation for Tuk and Inuvik

The naphtha from a topping plant at McKinley Bay or Tuktoyaktuk could be used to generate electricity for the communities of Tuktoyaktuk and Inuvik. A power plant at the topping plant location would eliminate the need for fuel storage and transportation; however, existing generating capacity at Inuvik or an expansion of the new facilities at Tuk may be more attractive options and could provide additional opportunities for cogeneration.

Alternatively, as mentioned earlier in the supply section, the residual could be used to offset the HFO that is currently imported from Norman Wells. The HFO from a local topping plant could be priced inexpensively, providing a cheap source of fuel for Inuvik, which is one of the larger communities in the Northwest Territories.

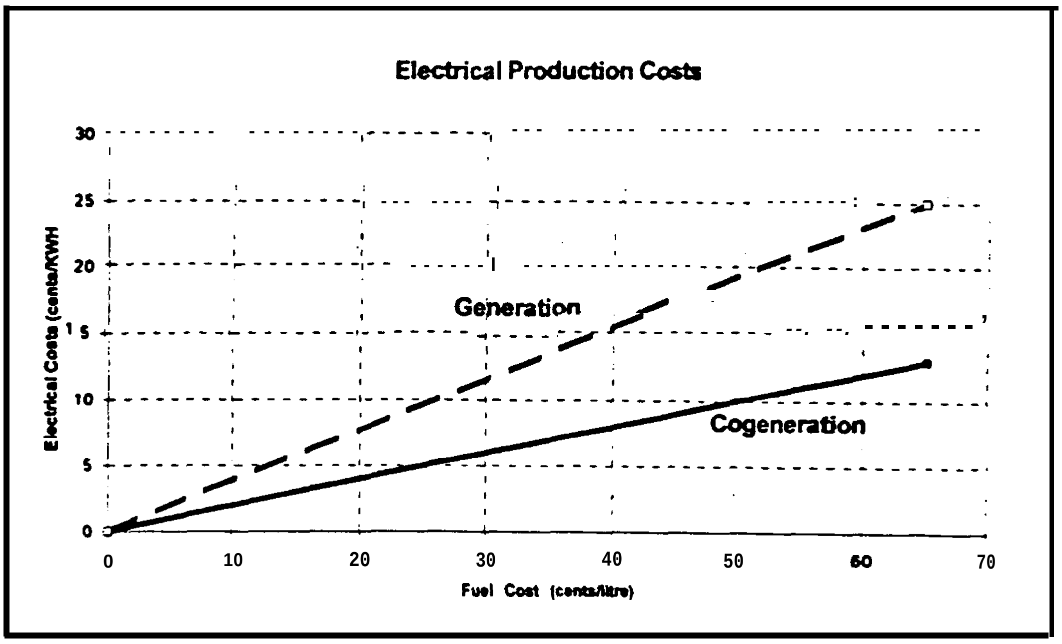
Cogeneration of Power and Heat

All the supply options considered in this report, with the exception of hydroelectric power, provide the opportunity for cogeneration. As the name implies, cogeneration is the sequential use of an engine to produce two forms of energy, heat and power. Cogeneration provides energy users with an opportunity to reduce their overall energy cost by investing in a high-efficiency on-site energy source.

The demand section of this report showed that three quarters *of the community energy demand goes into the production of heat and electricity. The high cost of fuel in the Northwest Territories has forced electrical producers to capture waste heat for further use. The Northwest Territories Power Corporation currently uses cogeneration in several communities to produce both electricity and heat. The Polaris mine uses cogeneration to produce heat to dry concentrate.

Figure 21 illustrates the economic impact of cogeneration on electricity production costs. The figure clearly shows that electricity costs increase substantially if the waste heat is not recovered.

Each cogeneration application is site specific; however, the existing and potential future mines which need to generate electricity and heat are excellent candidates for cogeneration.



Electrical Production Costs
Figure 21

New Industries

An inexpensive source of energy such as HFO may attract new industries to the area. In the analysis, it was assumed that the heavy fuel oil from the topping plant would be stored and then shipped to southern markets during the summer. It was further assumed that the market price would cover the shipping costs. This assumption is based on the premise that residual has no value in the North and, thus, it could be offered at a very low cost to new industries.

Economic Benefits

Developing local energy supplies provides additional economic benefits over and above the cheaper energy and employment opportunities which were identified eartier. These include government revenues in the form of royalties and taxes.

Taxes and royalties from the production facilities average approximately $7.5 million per year. Taxes from the topping plant revenues represent an additional $4 million per year.

Conclusions & Recommendations

Conclusions

Northern hydrocarbon resources can be economically developed to meet the energy needs of the mining industry and local communities.

> The viability, however, is dependent on all parties i.e. the producing company, the topping plant owner, and the transportation company working together to make it happen, and in return accepting a reasonable return on their investment. If one component of the supply chain becomes excessively expensive, as a result of higher capital costs, or expected higher returns, then the opportunity is lost.

Northern hydrocarbon resources can compete in the market place with alternative energy supplies such as back hauling of product from Europe or supplying product from existing sources.

> A local topping plant in the Tuktoyaktuk area can supply P50 diesel at a lower cost for all demand scenarios considered in the study. The supply cost is significantly lower than current practices and competitive with the back haul cost from Europe. From a mining perspective alone, however, the European supply is slightly more attractive, because of the lower transportation costs.

A northern topping plant would produce heavy fuel oil which could potentially be used by the mines as an inexpensive source of energy.

Heavy fuel oil would require heated storage and diesel engines designed to burn HFO, but the additional costs would be more than offset by the lower cost fuel

Unlike alternative sources, the development of local energy supplies would provide significant benefits.

- Local employment and training. Onshore oil development and a local topping plant could provide anywhere from 25 to 50 full time jobs that would help to train local people for future hydrocarbon opportunities.
- Economic benefit to the region in the form of a lower cost energy source, real revenues, taxes and royalties.
- A potential for spin-off businesses that could take advantage of a cheap energy source by using the residual from the topping plant to produce power and heat.

A number of other conclusions can be drawn from the study.

They are

- Onshore resource development is slightly more attractive than offshore development, and yields a lower product price.
- A topping plant at Bent Horn is not economically attractive compared to the other alternatives, because it would be too small, based on the limited reserves.
- Transporting diesel from the Tuktoyaktuk area to the Coronation Gulf using an ocean going barge similar to the All's Arctic Kiggiak is considerably cheaper than present day barging, and only slightly more expensive than back hauling from Europe.

Recommendations

A number of aftematives exist to supply energy to the mining industry and local communities at a lower cost than current practices:

- Hydroelectric power generation
- Local hydrocarbon development
- Back hauling product from Europe

This study has demonstrated that the last two alternatives are relatively competitive and it is the recommendation of NORTH OF 60 ENGINEERING LTD. that Energy Mines & Petroleum Resources continue to pursue these alternatives, to lower energy costs in the region.

Toward that end, it is recommended that EMPR circulate this report to interested parties for their review and comments. NORTH OF 60 ENGINEERING LTD. is willing to support the Department in addressing any questions that may arise from that review process.

A number of assumptions have been made to simplify the assessment process. The key assumptions are identified in the methodology section of this report. While NORTH OF 60 ENGINEERING LTD. believes they are reasonable and justified, the more important ones should be verified if industry shows interest in pursuing local hydrocarbon development as an energy source for the immunities and mining industry in the West Kitikmeot.

Acknowledgments

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Finally, NORTH OF 60 ENGINEERING LTD. would like to acknowledge the valuable assistance from Roy Ellis of the Bureau of Statistics, GNWT, in calculating the local benefits, and for the valuable input from the Petroleum Products Division of the Department of Public Works and Services, GNWT.

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Appendix A - Glossary

M$	million dollars
m^3	cubic metres (1 m^3 = 1000 litters)
m^3/yr	cubic metres per year
topping plant	a small refinery that fractionates crude oil into a number of products
DWT	Dead Weight Tonnes
TCF	Trillion cubic feet
Turbo B	Naphtha type jet engine fuel
P50 fuel	light diesel fuel with pour point of -50°F
P40 fuel	diesel fuel with a pour point of -40°F
HFO	heavy fuel oil
CPRA	Canadian Petroleum Resource Act
us	United States
Cdn	Canadian Currency
GNWT	Government of the Northwest Territories
EMPR	Department of Energy, Mines and Petroleum Resources
CASPPR	Canadian Arctic Shipping Pollution Prevention Regulations
OBO Carrier	Ore - Bulk - Oil Cam"er

Appendix B - Transit Analysis

Introduction

This appendix evaluates the transit times to move refined product from Bent Horn and the Tuktoyaktuk region to Coppermine in the Coronation Gulf. The transportation scenarios that have been mnsidered are seasonal. The purpose of this assessment is to evaluate the cost of supplying the communities and mining industry in the West Kitikmeot with local fuel as an alternative to importing the fuel from sources outside the Northwest Territories.

Transportation Alternatives

The options selected for evaluation were;

- the use of the MV Arctic, or similar class of vessel to transport refined product from Bent Horn to the Coronation Gulf.
- the use of ocean going barges, similar to the ATL Arctic Kiggiak, to transport product from the Beaufort Seato the Coronation Gulf.

Routing and Regulatory Access

The routes considered in this analysis along with distances and ice zone classifications are summarized in Table 1.

Access to the routes is governed by ice conditions and vessel type. These are summarized in Table 2.

Distance (NM) Arctic Zone	Beaufort Seato Coppermine	Bent Horn to Coppermine
11	290	275
12	200	
7		165
2		275
6		80
1		40
Totals	490	835

Route Distance by Ice Classification
Table 1

Class	Beaufort Routes		Bent Horn Routes	
	Earliest Entrance	Latest Exit	Earliest Entrance	Latest Exit
Arctic 4	July 5	Jan. 15	Aug. 15	Sept. 15
Arctic 3	July 5	Dec. 15	Aug. 20	Sept. 15
Arctic 2	July 10	Nov. 20	-	
Arctic 1	July 15	Oct. 20	-	
Type A	July 10	Oct. 31	-	
Type B	July 15	Oct. 20	-	
Type C	July 15	Oct. 15	-	
Type D	July 15	Oct. 10	-	
Type E	July 15	Sept. 30	-	

Shipping Season
Table 2

It should be noted that Table 2 is based on the worst ice regime along the route.

As is evident from the table, the two routes are quite different. The shipping season from the Beaufort is considerably longer than that from Bent Horn. The route from Beaufort Sea to the Coronation Gulf provides access to all types of vessels including Class E, which is essentially non Arctic rated, while Arctic Class 3 or Class 4 vessels are required to move product from Bent Horn. The Beaufort Sea route is essentially ice free during the summer months. Multi-year ice is not likely to be encountered, and there is a low to medium probability of encountering ice conditions which would be considered hazardous to the types of vessel listed in Table 3.

Transit Analysis

Vessel Specifications

The following vessels have been used as a basis to calculate transit times for each of the routes.

Vessel Specifications	Beaufort to Coronation Gulf	Bent Horn to Coronation Gulf
Vessel Type	Ocean Barge	Ship
Example Vessel	Arctic Kiggiak	MV Arctic
Capacity (m^3)	10,250	20,000
Length (m)	114	220
Beam (m)	31.9	22.9
Draft (m)	5.5	11
Power (MW)	5.4 (tug)	11
Speed, (open water) (kn.)	6-8 (towed)	17.2
Max. level ice (m)	N/A	1.5
Ice Class (CASPPR)	2	4

Vessel Specifications
Table 3

Transit Parameters

Table 4 summarizes the key parameters that have been used to calculate transit times and thus the number of trips per season.

	Beaufort to Coronation Gulf	Bent Horn to Coronation Gulf
Vessel Type	Ocean Barge	Ship
Example Vessel	Arctic Kiggiak	MV Arctic
Distance	490	835
Average Speed (knots)	7	10
sailing Time (days)	6	7
Loading/Offloading (days)	2	3
Round Trip (days)	8	10
Season Length (clays)	100	30
Maximum #trips	12	3
Minimum # trips	8	1
Average # trips	10	2

Transit Parameters
Table 4

From Table 4, it can be seen that, on average, 10 trips are possible between the Beaufort and the Coronation Gulf, while only two or three trips are feasible between Bent Horn and the Coronation Gulf.

Appendix C - Supply Cost Detail

Scenario A

- Current Supply Sources - Edmonton, Norman Wells, & East Coast
- Current Supply Sources+ Tuk Area & Bent Horn Topping Plants
- Current Supply Sources+ Europe

Scenario B

- Current Supply Sources - Edmonton, Norman Wells, & East Coast
- Current Supply Sources+ Tuk Area & Bent Horn Topping Plants
- Current Supply Sources+ Europe

Scenario C

- Current Supply Sources - Edmonton, Norman Wells, & East Coast
- Current Supply Sources+ Tuk Area & Bent Horn Topping Plants
- Current Supply Sources+ Europe

Scenario A

Optimum Supply Scenario

Community / Industry	Refinery / Topping Plant Demand 10^3m^3					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik					2.45	
Cambridge Bay					4.75	
Coppermine						
Gjoa Haven					2.19	
Holman Island					1.54	
Inuvik					29.25	
Paulatuk					0.68	
Resolute				2.44		
Sachs Harbor					0.89	
Taloyoak					2.30	
Tuktoyaktuk					4.11	
George Lake		2.83				
Izok Lake		21.00				
Lac de Gras						
Lupin		20.00				
Nanisivik				10.00		
Polaris				16.(MI		
Smelter						
Ulu						
Petroleum					5.00	
Total		43.83		28.44	53.16	

P50 Price $/m'

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	S213.00
Capacity 10^3M^3	0	500	0	500	75	c

Supply Price **$41.57 M$** - Based on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from current sources - Edmonton, Norman Wells and East Coast.

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1 1/24/93

Scenario A

Optimum Supply Scenario

Community / Industry	Refinery /Topping Plant Demand 10^3m^3					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktul
Aklavik						2.45
Cambridge Bay						4.75
Coppermine						
Gjoa Haven						2.1s
Holman Island						1.54
Inuvik						29.25
Paulatuk						0.68
Resolute				2.44		
Sachs Harbor						0.89
Taloyoak						2.30
Tuktoyaktuk						4.11
George Lake						2.83
Izok Lake						21.00
Lac de Gras						
Lupin						20.00
Nanisivik				10.00		
Polaris				16.00		
Smelter						
Ulu						
Petroleum						5.00
Total				28.44		96.99

P50 Price $/m³

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	50	500	0	500	75	125

Supply Price $31.05 M$ - Based on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from local sources at Tuk and Bent Horn plus current sources - Edmonton, Norman Wells and East Coast.

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Scenario A

Optimum Supply Scenario

Community / Industry	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
	Refinery / Topping Plant Demand 10^3m^3					
Aklavik			2.45			
Cambridge Bay			4.75			
Coppermine						
Gjoa Haven			2.19			
Holman Island			1.54			
Inuvik			29.25			
Paulatuk			0.68			
Resolute			2.44			
Sachs Harbor			0.89			
Taloyoak			2.30			
Tuktoyaktuk			4.11			
George Lake			2.83			
Izok Lake			21.00			
Lac de Gras						
Lupin			20.00			
Nanisivik			10.00			
Polaris			16.00			
Smelter						
Ulu						
Petroleum			5.00			
Total			125.43			

P50 Price $/m^3

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	0	500	200	500	75	0

Supply Price $34.20 M$ - Based on P50 Price and Transportation Costs

Comments:

Supply Options - Supply from Europe plus current sources - Edmonton, Norman Wells and East Coast

Scenario B

Optimum Supply Scenario

Community / Industry	Refinery I Topping Plant Demand 10^3m^3					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik					2.45	
Cambridge Bay					4.75	
Coppermine						
Gjoa Haven					2.19	
Holman Island					1.54	
Inuvik					29.25	
Paulatuk					0.68	
Resolute				2.44		
Sachs Harbor					0.89	
Taloyoak			0.00		2.30	
Tuktoyaktuk					4.11	
George Lake		2.83				
Izok Lake		21.00				
Lac de Gras		55.00				
Lupin		20.00				
Nanisivik				10.00		
Polaris				16.00		
Smelter						
Ulu		7.00				
Petroleum					5.00	
Total		105.83	0.00	28.44	53.16	

P50 Price $/m'

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	0	500	0	500	75	0

Supply Price $57.57 M$ - Based on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from current sources - Edmonton, Norman Wells and East Coast.

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Scenario B

Optimum Supply Scenario

Community I Industry	Refinery / Topping Plant Demand 10^3m^3 Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik						2.45
Cambridge Bay						4.75
Coppermine						
Gjoa Haven						2.19
Holman Island						1.54
Inuvik						29.25
Paulatuk						0.68
Resolute				2.44		
Sachs Harbor						0.89
Taloyoak						2.30
Tuktoyaktuk						4.11
George Lake						2.83
Izok Lake		6.99				14.01
Lac de Gras						55.00
Lupin		20.00				
Nanisivik				10.00		
Polaris				16.00		
Smelter						
Ulu		7.00				
Petroleum						5.00
Total		33.99		28.44		125.00

P50 Price $/m'

	Refinery / Topping Plant Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	50	500	0	500	75	125

Supply Price $46.28 M$ - Based-on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from local sources at Tuk and Bent Horn plus current sources - Edmonton, Norman Wells and East Coast.

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Scenario B

Optimum Supply Scenario

Community / Industry	Refinery / Topping Plant Demand 10^3m^3					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik			2.45			0.00
Cambridge Bay			4.75			
Coppermine						
Gjoa Haven			219			
Holman Island			1.54			
Inuvik			29.25			
Paulatuk			0.68			
Resolute			2.44			
Sachs Harbor			0.89			
Taloyoak			2.30			
Tuktoyaktuk			4.11			
George Lake			2.83			
Izok Lake			21.00			
Lac de Gras			55.00			
Lupin			20.00			
Nanisivik			10.00			
Polaris			16.00			
Smelter						
Ulu			7.00			
Petroleum			5.00			
Total			187.43			0.00

P50 Price $/m³

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	0	500	200	500	75	0

Supply Price $47.58 M$ - Based on P50 Price and Transposition Costs

Comments:

Supply Options -Supply from Europe plus current sources - Edmonton, Norman Wells and East Coast

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Scenario C

Optimum Supply Scenario

Community / Industry	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
	Refinery / Topping Plant Demand 10³m³					
Aklavik					2.45	
Cambridge Bay					4.75	
Coppermine		20.00				
Gjoa Haven					2.19	
Holman Island					1.54	
Inuvik		3.16			26.09	
Paulatuk					0.68	
Resolute				2.44		
Sachs Harbor					0.89	
Taloyoak					2.30	
Tuktoyaktuk					4.11	
George Lake		2.83				
Izok Lake		21.00				
Lac de Gras		55.00				
Lupin		20.00				
Nanisivik						
Polaris				16.00		
Smelter					20.00	
Ulu		7.00				
Petroleum					10.00	
Total		128.99		18.44	75.00	

P50 Price $/m³

	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
	Refinery / Topping Plant					
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10³M³	0	500	0	500	75	0

Supply Price **$77.84 M$ - Based on P50 Price** and Transportation Costs

Comments

Supply Options -Supply from current sources - Edmonton, Norman Wells and East Coast.

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Scenario C

Optimum Supply Scenario

Community / Industry	Refinery / Topping Plant Demand 10^3m^3					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktul
Aklavik						2.45
Cambridge Bay						4.75
Coppermine						20.00
Gjoa Haven						2.19
Holman Island						1.54
Inuvik						29.25
Paulatuk						0.68
Resolute				2.44		
Sachs Harbor						0.89
Taloyoak						2.30
Tuktoyaktuk						4.11
George Lake						2.83
Izok Lake		21.00				
Lac de Gras		30.99				24.01
Lupin		20.00				
Nanisivik						
Polaris				16.00		
Smelter						20.00
Ulu		7.00				
Petroleum						10.00
Total		78.99		18.44		125.00

P50 Price $/m³

	Refinery / Topping Plant					
	Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.00
Capacity 10^3M^3	50	500	0	500	75	125

Supply Price $54.85 M$ - Based on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from local sources at Tuk and Bent Horn plus current sources - Edmonton, Norman Wells and East Coast.

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Scenario C

Optimum Supply Scenario

Community / Industry	Refinery /Topping Plant Demand 10^3m^3 Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
Aklavik			2.45			
Cambridge Bay			4.75			
Coppermine			20.00			
Gjoa Haven			2.19			
Holman Island			1.54			
Inuvik			29.25			
Paulatuk			0.68			
Resolute			2.44			
Sachs Harbor			0.89			
Taloyoak			2.30			
Tuktoyaktuk			4.11			
George Lake			2.63			
Izok Lake			21.00			
Lac de Gras			55.00			
Lupin			20.00			
Nanisivik						
Polaris			16.00			
Smelter			20.00			
Ulu			7.00			
Petroleum			10.00			
Total			222.43			

P50 Price $/m³

	Refinery /Topping Plant Bent Horn	Edmonton	Europe	Montreal	Norman Wells	Tuktoyaktuk
P50 Price	$392.00	$198.00	$200.00	$200.00	$290.00	$213.01
Capacity 10^3M^3	o	500	225	500	75	0

Supply Price $55.79 M$ - Based on P50 Price and Transportation Costs

Comments:

Supply Options -Supply from Europe plus current sources - Edmonton, Norman Wells and East Coast.