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INUVIK GAS SUPPLY

FEASIBILITY STUDY

Prepared by:

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DECEMBER 1980

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1.0 SCOPE

1.1 General

This report documents the engineering and feasibility study performed by Canuck Engineering Ltd. concerning the supply of natural gas by pipeline to the Town of Inuvik from nearby fields at Parsons Lake or Ya Ya.

1.2 Engineering Topics

The principal engineering and economic topics addressed are:

(a) Assessment of projected town requirements;
(b) Preliminary evaluation of gas field supply alternatives;
(c) Well development requirements and design;
(d) Wellhead facilities requirements and design;
(e) Gas plant requirements and design;
(f) Pipeline requirements and design including route selection and hydraulics;
(g) Capital cost analyses for all facilities;
(h) O & M cost analysis for the combined facilities;
(i) Construction plan outline;
(j) Project economic analysis including cost of service.

Excluded from the study are:

(a) Gas purchase contract negotiations;
(b) Environmental archaeological or sociological input studies;
(c) Town gas distribution system design.

The studies were conducted at a "preliminary engineering design" level in sufficient detail to establish a basis for reliable capital and operating cost estimates. No attempt has been made to optimize the components of the system.

1.3 Data Sources

1.3 Data Sources

The primary sources of project-specific data were as follows:

Gulf Canada Ltd.	Gas field data, well development costs, processing plant requirements
Northern Canada Power Commission	Inuvik energy consumption data, power line routing
Northwest Territorial Government	Demographic Data
Canuck Engineering Ltd.	On-hand studies and reports for the area (principally studies related to CAGPL and Foothills pipelines).

2.0 INTRODUCTION

2.1 General

The Town of Inuvik derives its present energy requirements using liquid fuels (diesel and Bunker "C") produced from the Norman Wells refinery and barged to Inuvik. Most of this fuel (approximately 80%) is consumed at the central Northern Canada Power Commission facility which produces electricity for Inuvik and Tuktoyaktuk and which distributes heat by circulating hot water through utilidors to much of the town.

Present fuel consumption at the NCPC facility is approximately half "heavy fuel oil 6303" and half "marine LS diesel". Recent data for the NCPC facility is shown in Table 2.1.1. Energy consumption at the NCPC facility has been approximately 800 x 10^9 BTU/yr. Including consumption at sites not connected to the NCPC system, present consumption is increased to approximately 1000 x 10^9 BTU/yr. Peak consumption rates on a daily basis (excluding short duration increases due to electricity demand) are approximately 75% higher than the average. These data are based on the period 1976-1980 for which the town population has been close to 3000.

2.2 Gas Demand

Energy use (other than transport) at the Town of Inuvik may be characterized as follows:

Central NCPC facility
All others

The NCPC facility presently consumes approximately 80% of all energy (i.e. liquid fuel) supplied to the town. Moreover, the NCPC facility is the hub of two distribution networks, the electrical distribution system for Inuvik and Tuktoyaktuk and the hot water heating distribution system for Inuvik. Other users consume liquid fuel for heating, but

TABLE 2.1.1

INUVIK NCPC FACILITY ENERGY SUPPLY AND CONSUMPTION DATA

	Inuvik - Tuktoyaktuk System Electricity				Inuvik - Heating			
Year	Generation (MWH)	Sales (MWH)	Max. Demand (KW)	Diesel Fuel (Gallons)	Heat Sales (BTU)	Boiler Fuel (Gallons)	Water Sales (Gallons)	Total BTUS Consumed x 10^9
76/77	29,144	24,396	5,300	1,819,223	219 x 10^9	2,362,428	35,452,270	765
77/78	31,890	25,736	6,100	1,819,469	274 x 10^9	2,439,981	41,321,381	780
78/79	34,992	26,681	6,400	1,937,564	254 x 10^9	2,550,564	45,442,147	820
79/80*	33,397	27,715	6,750	2,152,224	196 x 10^9	2,000,000	43,043,921	760

*ESTIMATED

the fuel on-site locally and are not connected to a continuous supply source.

Virtually all ultimate energy users may be classed as residential or commercial with no industrial users. Energy consumption is principally for space heating, lighting and small electric motors, assuming energy used for transportation is excluded. The pattern of energy consumption is similar for residential and commercial users. The heating component closely follows the annual weather cycle while electricity consumption (excluding diurnal variations) also shows an increase in winter due to greater lighting demand.

In considering projected energy demand as a basis for gas supply requirements, it is necessary to forecast future population size and energy consumption patterns. Demographic data supplied by the Territorial Government for the Town of Inuvik show that recently town population has been shrinking.

TABLE 2.2.1

TOWN OF INUVIK POPULATION STATISTICS

Date	Population	Net Change
December 31, 1977	3,127	
December 31, 1978	2,938	-189
December 31, 1979	2,892	- 46

Data for the period December 31, 1978 to December 31, 1977 shows population change to be comprised as follows:

Births	95
Deaths	14
Out-Migration	127 (net)

Statistical data based on net growth rates for each ethnic segment of the population, excluding in-migration and out-migration, project an annual growth rate of 1.3%.

Accordingly, three growth scenarios for the Town of Inuvik were considered based on possible development:

(a) No-growth, based on a constant or shrinking population and little development in the area;

(b) Slow-growth, based on some development or exploration in the area using Inuvik as supply and service centre;

(c) Fast-growth, based on a major project in the area, such as the Dempster pipeline.

For each case present energy consumption patterns were assumed to continue. This presupposes that insulation standards building types, resident al-commercial-industrial uses etc. wi not change drastically.

The slow-growth scenario was chosen as the basis for this study, since although it is not necessarily the most probable, it is most representative of system economic and engineering requirements. The no-growth scenario militates against large capital expenditures for a declining population. The fast-growth scenario can distort the study; the present town could be burdened with the cost of larger facilities to supply the future larger population. Moreover, for fast growth, there is a probability of alternate energy sources (such as a pipeline) being available and more attractive than a supply from YaYa or Parsons Lake.

While no gas distribution system has been included in this study, the projected slow-growth scenario assumes 100% capture of the Inuvik energy market. Projected gas demand is shown in Table 2.2.2.

TAB

INUVIK PROJ

Year	Population
1979	2,892
1985	3,150
1990	3,360
1995	3,584
2000	3,823

NOTES

1) Slow-growth: 1.3% annually
2) Capture of 100% of Inuvik market
3) Present (1980) consumption patterns
4) Peak/average ratio 2:1 (presently 1.

2.3 Gas Supply

Two alternate gas supply sources were considered:

(a) the Parsons Lake Field located 40 miles north of Inuvik;
(b) the Ya Ya Field located 70 miles northwest of Inuvik on Richards Island.

The operator for both fields is Gulf Canada Ltd. Much reliance was placed on Gulf's assessment of the relative merits of the two fields.

The Parsons Lake Field produces gas and condensate with a composition as shown in Table 2.3.1. Reservoir and well data are shown in Table 2.3.2. The production configuration required includes: two gas production/injection wells and one each water injection and condensate injection wells at formation depth.

The Ya Ya Field produces sweet gas with a lower amount of condensate and carbon dioxide than Parsons Lake Field. The wells are much shallower (approximately 5500 feet) than at Parsons Lake. Moreover, the extent of the reserves is not fully known; further drilling would be required to adequately define the field's resources. The lack of adequate data on this field including potential problems argues against any commitment for gas supply from this field until it is adequately proved up. In the absence of such data, a field production configuration at Ya Ya identical to Parsons Lake facilities have been assumed.

Accordingly, this report focusses on the Parsons Lake supply; the Ya Ya supply analysis is included in Appendix 1.

TABLE 2.3.1

PARSONS LAKE FIELD

TYPICAL PRODUCTION COMPOSITION (DRY BASIS)

Component	Mol %
Nitrogen	1.50
Carbon Dioxide	3.30
Methane	87.49
Ethane	3.59
Propane	1.61
I-Butane	0.35
N-Butane	0.55
I-Pentane	0.24
N-Pentane	0.22
N-Hexane	0.17
Cyclohexane	0.15
Benzene	0.04
N-Heptane	0.10
Methylcyclohexane	0.16
Tol uene	0.09
N-Octuane	0.05
N-Xylene	0.11
N-Noname	0.10
N-Decane	0.04
N-Undecane	0.02
N-Tetradecane	0.12
TOTAL	100.00

TABLE 2.3.2

PARSONS LAKE FIELD

TYPICAL PRODUCTION DATA

Wellhead Shut-In Pressure	3500 psia
Wellhead Flowing Pressure	1300 psia
Wellhead Temperature	85°F
Liquid Production Rate (Hydrocarbon)	14.4 bbl/MMcf
(Free Water)	1 bbl/MMcf
Avg. Molecular Wt. of C6+ Fraction	92.7
Specific Gravity of C6+ Fraction	.739

2.4 Geotechnical Data

In developing designs for Arctic wells, production, treating and transportation facilities, it is necessary to consider the geotechnical data relating to permafrost, seismicity and stability.

Permafrost

In the Inuvik area permafrost is continuous except under rivers and large bodies of water. A thin active surface layer, several feet thick thaws each summer but refreezes completely down to the permafrost in winter. Previous experience in permafrost areas has demonstrated that permafrost soils may undergo degradation, erosion and mass movement if not properly treated. On the other hand, most soils are stronger in the frozen state, and techniques have been developed whereby reliable foundations can be constructed and the terrain can be protected by careful engineering. Permafrost around the buried pipeline can be retained by transporting the gas at temperatures below the freezing point of water.

Permafrost under heated buildings may be prevented from degradation by one or a combination of the following methods:

(a) Insulation of the permafrost using a thick (3′ - 10′) layer of gravel, possibly installed over an additional insulating layer such as styrofoam board;

(b) Erection of buildings on piles with a breezeway beneath the insulated floors of the building;

(c) Refrigeration of the soil beneath buildings.

Surficial Geology

Between Inuvik and Richards Island, bedrock is mantled by till, glaciofluvial, glaciolacustrine marine, and alluvial-deltaic sediments. Till overlies unconsolidated Tertiary sand and gravel above elevation 500 feet. The thickness of the till is variable, with bedrock appearing at or near the surface at some localities, e.g. between Noell and Parsons lakes.

Hummocky ice-contact stratified drift and preglacial outwash occur near Wolverine Lake and also extend from north of Parsons Lake to Richards Island.

On the Arctic Coastal Plain north of the Caribou Hills to Parsons Lake, and on Richards Island sandy marine, postglacial lacustrine silty clay and glaciofluvial silt, sand, and gravel are common below elevation 300 feet. Till and scattered sand and gravel deposits are present above elevation 300 feet.

Permafrost is continuous from Inuvik to Richards Island. Thermokarst lakes and peat-filled depressions are abundant.

Ground Temperatures

The temperatures at the ground surface are generally different from but close to the ambient air temperatures. The seasonal variation in ground temperature decreases with depth because the ‘thermal inertia’ in the ground damps out the large temperature variations which occur at its surface. Typical ground temperatures at a depth of 6 feet are tabulated below:

TABLE 2.4.1
GROUND TEMPERATURES
AT A SIX-FOOT DEPTH

Date	Temperature °F
March	11
September	26

Seismicity

The design of structure to resist seismic motions must consider the earthquake intensity, the structural parameters governing its response, and the permissible or allowable levels of response, such as stress or strain and deflection.

In the Inuvik area, the area of highest earthquake activity is south of the Mackenzie Delta in the Richardson Mountains. Its centre is about one hundred miles south and west of the proposed pipeline and is enclosed by contour number five. North of Inuvik, the seismic activity is low and should present few problems.

Stability and Erosion

Erosion as discussed in this section refers to accelerated erosion caused by man-made removal or disturbance of surface vegetation and soil. Once initiated, the rills and gullies that rapidly form can be difficult to control. Such erosion in the vicinity of the pipeline right-of-way would be undesirable, and would be detrimental to natural revegetation and restoration measures. The effects of accelerated erosion can be prevented by controlling surface run-off and ground water flow across the areas disturbed by the construction and operation of the pipeline.

Drainage and erosion control measures will be incorporated into pipeline construction to minimize detrimental corrosion.

Erosion will be controlled by minimizing interference with natural drainage patterns, until the protection of the revegetation becomes effective. Natural revegetation will provide stabilized cover to the ground surface.

The pipeline has been located so that the terrain traversed is flat to gently undulating. In general, such slopes are considered stable irrespective of the existing soil conditions.

3.0 DESIGN AND CONSTRUCTION APPROACH

3.1 Design Approach

The design approach was predicated on evolving the lowest cost system consistent with acceptable performance and reliability. To accomplish this, the following points were adhered to:

(a) Use of local contractors, subcontractors, equipment and supplies rather than “southern Canada” sources, wherever possible, for construction and operation;

(b) Limiting use of redundancy and spares to essential equipment such as rotating machinery;

(c) Elimination or reduction of transportation facilities, such as gravel roads, airstrips and docks relying instead on snow roads for construction and helipads for operation;

(d) Eliminating expensive contingency equipment such as an on-site service rig;

(e) using the simplest gas processing facilities consistent with a satisfactory sales gas product, by eliminating CO_2 removal or extensive liquid hydrocarbon processing.

3.2 Construction Approach

The construction approach was based on the design approach outlined above. It was assumed that local contractors would be used for the pipeline facilities and much of the processing plant work. This would reduce expensive mobilization costs for men and equipment. Winter construction of the pipeline and plant and wellhead site work was assumed during the period February-May. Some work, such as gravel excavation and stacking for drainage at the main gravel site two miles southwest of Hans Bay, was assumed to take place the previous fall. All material for the plant and pipeline would be staged at Inuvik by the end of the summer shipping season and hauled to the work sites over snow roads. It was assumed that much of the plant and well head equipment would be in the form of pre-fabricated modules minimizing assembly difficulties during construction. Plant construction would extend into the summer and a fall start-up date is targeted.

Construction schedule milestones are shown in Table 3.2.1 on a very optimistic basis for start-up in the fall of 1981. A realistic schedule would almost certainly require an additional year with start-up in 1982.

TABLE 3.2.1

CONSTRUCTION SCHEDULE

Activity	Summer 1980	Late Summer 1980	Fall 1980	Winter 1980-81	Spring 81	Summer 81	Fall 81
Preliminary Design	x						
Application & Hearings	x						
Final Design		x					
Procurement		x	x				
Transport		x	x	x			
Contract Awards		x					
Land & Survey		x	x				
Preliminary Site Work			x				
Well Drilling			x	x	x		
Plant Construction					x	x	x
Pipeline Construction					x		
Start-Up							x

4.0 FACILITIES DESIGN

4.1 General

The design of the facilities has been based on the data previously cited and on the design and construction approach documented above. The facilities are described in terms of the natural flow of the gas from the well to the town gate meter station.

4.2 Well Design

The well design for both the Ya Ya and Parsons Lake field is predicated on the "cluster arrangement" specified by Gulf. A total of four wells per cluster is assumed as follows:

(a) Two gas production/injection wells which are identical and are used alternately for gas production and excess gas re-injection;

(b) A water disposal well at or below formation depth;

(c) A liquid hydrocarbon disposal well at formation depth.

Cluster spacing of approximately one mile between wells has been assumed. All wells would be 9000-11000 feet deep depending on the exact location of the production or injection zone. The permafrost layer is about 2000 feet thick and special techniques are necessary to prevent problems such as hydrate formation in gas and hydrocarbon wells or freezing in water injection wells. To alleviate these difficulties, the following methods have been employed:

(a) All wells use recirculation of refrigerant propane to prevent degradation of the permafrost;

(b) All wells use recirculation of hot oil to maintain the temperature of the produced or injected fluid;

(c) The cold propane and hot oil recirculation systems are insulated from each other;

(d) Gas production and injection rates are a minimum of 5 MMcfd and a maximum of not less than 10 MMcfd (20 MMcfd may be possible from a single well);

The well requirements for a gas producing/injection well are summarized in Table 4.2.1; the requirements for liquid hydrocarbon or water wells are similar.

4.3 Wellhead Facilities

At each wellhead local facilities are included to control, operate and protect the well, to process the wellhead fluid to the extent necessary for production or injection, and to monitor all wellhead processes on an ongoing basis. Some facilities are also included to aid in testing or servicing the wells if necessary. A summary of the principal systems at the gas production/injection wells, water injection well and hydrocarbon injection well is summarized in Table 4.3.1. A gas production well schematic is shown in Figure 4.3.1.

4.4 Well Flowlines

Each well in the cluster is connected to the central processing plant by above-ground connecting facilities. These facilities consist of support frames frozen into the permafrost supporting the gas water or hydrocarbon flowlines, the propane refrigerant recirculation lines, electrical heat tracing lines and electric power and data transmission and communication lines. All fluid lines are insulated and those in which freezing or hydrate formation is possible are electrically traced to maintain an elevated temperature.

TABLE 4.2.1

GAS PRODUCTION/INJECTION WELL REQUIREMENTS

Well Material Requirements Including:

Thermal Casing

Production Casing

Propane and Oil Recirculation Casing

Cementing of Casing

Wellhead Valve Assembly
(Christmas Tree)

Subsurface Equipment (Packers, etc.)

Well Drilling Services Including:

Drilling RigTime

Labour

Contractors Overhead and Profit

Well Testing Completion Services Including:

Wireline and Logging Service

Cementing Services

Stimulating Services

Production Testing

Other Services Including:

Camp Facilities

Logistics, Transport and Mobilization

Equipment Rentals

TABLE 4.3.1

PRINCIPAL WELLHEAD FACILITIES

Facility	Production/Injection	Water Injection	Hydrocarbon Injection
	Well Type		
Safety Shut-In	x	x	X
Pressure Control	x	X	X
Corrosion Inhibitor Injection	X	x	x
Freeze-Up Inhibitor Injection	X	X	X
Hot Oil Circulation	x	x	x
Propane Refrigerant Circulation	X	x	X
Flare and Relief System	X		X
Electrical Power and Lighting (Including Emergency System)	x	X	X
Metering and Measurement System	x	X	X
Injection Squeeze System		X	X
Liquids (Fuel, Inhibitor, etc.) Storage	X	X	X
Heating System	X	X	X
Emergency Living Accommodation	X	X	X
Storage/Garage Building	X	X	X
Life Support System	x	X	X

4.5 Gas Plant

The function of the gas plant is to receive natural gas from the gathering system, process it, and deliver it in a condition suitable for transportation by buried pipeline to the town gate at Inuvik. This will entail delivering the gas within prescribed limits for pressure, temperature and composition.

The composition of the wellhead gas (based on Parsons Lake data) shows no sulphur but some carbon dioxide. The absence of sulphur means that no extraction process is required. The natural gas emerging from the well head may be expected to be saturated with water vapour; in addition, some free liquid water may be present. It is necessary to reduce the water content of the gas to ensure that problems caused by hydrate formation do not occur. The pipeline to Inuvik is buried and gas delivered to it assumes a temperature approaching that of the permafrost around the pipeline. The water content of the gas must be sufficiently reduced to prevent hydrate formation anywhere along the length of the pipeline. Condensable hydrocarbons must also be prevented from reaching the pipeline. Liquid hydrocarbons and the associated two-phase flow reduce the transmission efficiency of the pipeline. If heavy hydrocarbons were present in only small amounts, occasional pigging of the line would be sufficient to maintain transmission efficiency. However, a heavy hydrocarbon removal step is definitely required before the gas is delivered to the pipeline from the Parsons Lake field and would also probably be required for the Ya Ya field.

In designing a condensable hydrocarbon removal step it is necessary to know the shape of the phase diagram on the pressure - temperature plane. This implies an accurate determination of the quantities of heavy hydrocarbons present in the gas.

For preliminary design, however, the following assumptions are generally true. The maximum pressure on the phase envelope locus seldom occurs above 1100 psia. Cooling above this pressure will not remove any heavy hydrocarbons. The maximum temperature at which liquid forms generally occurs around 800 psia in the form of a "bulge" on the right hand side of the curve. This bulge is responsible for the phenomenon of retrograde condensation. As the pressure is reduced at constant temperature, a liquid phase occurs and disappears. Since the pipeline to Inuvik operates at essentially ground temperature, its "operating line" is a similar vertical line " on the pressure-temperature plane.

To accomplish the objective of water and hydrocarbon dewpoint depression, several alternate schemes were considered at a conceptual level . The object was not to select the optimum process but to choose a technically and economically feasible design on which to base a cost estimate. Alternate plant processes considered were:

(a) Dessicant absorbers or molecular sieves;
(b) Glycol and/or lean oil absorption;
(c) Chilling and three-phase separation.

Water and hydrocarbon removal by chilling and expanding the gas was selected because:

(a) the water vapour removal step is relatively uncomplicated;

(b) the capital investment appears to be lower;

(c) the operational reliability and maintainability of the process is expected to be good;

(d) the fuel gas consumption is relatively low.

The gas processing plant has been designed for 12 MMcfd capability based on a minimum gas production or injection rate of 5 MMcfd. Expected Inuvik peak demand in the year 2000 is approximately 6.8 MMcfd which leaves a minimum injection rate of 5.2 MMcfd. The plant is based on a refrigerated flash process for hydrocarbon and water dewpoint control at 0°F and 800 psia. Expected plant inlet conditions are 12 MMcfd gas (including hydrocarbon liquids and water) at 1100 psia and 85°F. Depending on Inuvik gas demand, 5 to 10 MMcfd of gas would be reinfected. The hydrocarbon liquids separated in the inlet separator and chilled separator are stabilized and stored for subsequent reinfection. The water from the inlet separator is treated and stored for subsequent reinfection; water separated in the chilled separator is boiled off in the glycol regeneration process.

A process schematic is shown in Figure 4.5.1.

In developing a plant layout (Figure 4.5.2), it was considered desirable to segregate the equipment into separate buildings to permit tailoring of facilities such as cranes and acoustic treatment to specific requirements.

The turbine building houses the turbines used for propane refrigeration and gas compression. The process building houses most of the vessels and heat exchangers. The electric generating and distribution equipment is housed in the utility building which also houses the glycol reboiler skid, the fuel gas skid and the heating boilers. In addition, the control room for the gas plant, gathering line and pipeline is located adjacent to this building. The warehouse/shop building contains the spares and supplies needed to maintain the plant (and the gathering system) and workshop facilities for light duty maintenance and repair. The liquid storage area is immediately adjacent to this building and contains tanks and/or bladders for glycol, fuel and water, inhibitor, methanol and other required liquids.

The plant block, bypass and blowdown valves are located in the meter station building with the flowmeters some distance away from the other buildings. This provides a safety feature should a major emergency arise.

The entire plant site is gravelled over a styrofoam board base to protect the permafrost. The technique of elevated construction on piles extending several feet above grade was selected primarily due to the need to protect the permafrost from degradation. Elevated construction also facilitates the installation of piping which may be installed above grade but below floor level.

Buildings will be framed metal buildings with metal skin sandwich panels enclosing polyurethane foam. Insulated soffit panels are installed beneath the buildings to prevent damage to the permafrost from radiation. Frames are required to support cranes and turbine exhausts, and for wind resistance. Self-framed buildings, reinforced and cross-braced on-site, may be adequate, at least for some buildings, and would effect savings in cost and construction time.

Major plant systems are summarized in Table 4.5.1. A discussion of some key features of plant design follows.

The natural gas and propane compression turbines are based on the Solar Saturn. A spare unit of each type is included in case of breakdown. The electric generation equipment is of the dual fuel (diesel/gas) type and also includes a spare unit.

All vessels with the exception of the hydrocarbon separator are designed for 1440 psia, permitting operation at any expected gathering line pressure. The inlet and glycol separators are designed for three-phase operation; the inlet separator also includes a slug-catcher. Heat exhangers and chillers are of shell and tube design.

The instrumentation and control system is based on minicomputer logic with CRT and conventional displays in the control room.

Building heat is supplied by a hot water-glycol recirculating system, sized to provide sufficient heat under shutdown conditions in mid-winter. The system is designed to operate on a dual-fuel basis.

The fire control system is based on bottled Halon gas supplemented with fire extinguishers in appropriate locations. Gas and fire detectors are included.

Both gas and liquid flare systems are provided at a distance from the buildings. A vertical stack is used for gas and a gravelled lagoon flare for liquids. The propane refrigeration system incorporates its own separate flare. No flaring would be necessary during routine operation of the plant.

4.6 Camp and Support Facilities

The camp facilities are based on prefabricated module-type housing providing accommodation for three operating personnel with sufficient additional space for nine additional personnel which may be required during annual gathering system and plant maintenance or for additional maintenance required at the wells, should problems arise such as condensate plugging, etc. The camp facilities will be located at least one-half mile from the plant and will be connected to it by gravel road. The helipad and vehicle storage areas will be adjacent to the camp. Gravel roads will connect the camp area, plant and wellsite to permit year-round access. A helipad with unheated storage buildings has been included but no airstrip or dock facilities at Hans Bay. The plant and well area could normally be reached overland only by snow road in winter when supplies would be brought in for Inuvik.

TABLE 4.5.1

GAS PLANT MAJOR SYSTEMS

Gas Processing Vessels and Heat Exchangers

Gas Reinfection and/or Compression Turbo Machinery

Propane Refrigeration Vessels and Heat Exchangers
Chillers and Condensers

Propane Refrigeration Turbo Machinery

Gas Piping and Valves

Propane Piping and Valves

Glycol Regeneration Equipment

Process Water Treating

Potable Water Supply

Sewage Treatment and Disposal

Electricity Generation and Distribution

Control and Communication

Instrumentation

Relief and Flare

Liquid Storage and Transfer

Heating System

Fire Detection and Control

Metering and Measurement

Instrument Air

4.7 Pipeline

The Parsons Lake pipeline transports gas from the gas plant to the Inuvik town gate. The principal phases of pipeline design are:

(a) Routing
(b) Hydraulics
(c) Pipe and Ancillary Facility Specification and Design

For the Parsons Lake route, it was decided to adopt an "energy corridor" approach with the pipeline located adjacent to the 69 kV electrical transmission line. This route diverges only slightly from the most direct course and the problems avoided with environmental impact largely compensate for any difficulties in construction or operation due to induced electrical effects. Detailed routing was based on 1:50000 topographical maps and aerial photography. The delivery point was selected as a meter and regulating "town gate" station located northeast of the town. From here, a medium-pressure distribution line would carry gas to the NCPC plant and to other users if the distribution system was extended.

The route selected (Drawing INU1-1011-1S) is consistent with the general principles and industry standards which include staying on higher and drier surfaces, avoiding areas of potential instability, avoiding interruption of surface drainage, minimizing pipe buoyancy control measures and minimizing the amount of terrain where ditching is difficult. A buried pipeline was selected instead of an above--ground line because of avoidance of difficulties such as:

(a) Interference with large mammal movement
(b) Interference with vehicular or other ground surface traffic
(c) Susceptibility to accidental damage
(d) Anticipated higher maintenance costs
(e) More stringent code requirements relating to pipeline materials
(f) More stringent natural gas specifications, particularly affecting water and hydrocarbon dewpoints

The last point is of particular concern as the predictability of the equilibrium values of hydrates and water vapour at such low temperatures is difficult. It is certain, however, that it would require more complex and costly gas treating facilities.

Pipeline hydraulics analysis was based on the route selected and on the volume and composition of the gas produced from the gas processing plant. The analysis was performed using a Canuck Engineering in-house computer program which solves the heat transfer and flow equations simultaneously. Both 4.500 inch and 6.625 inch alternatives were examined. The smaller size is incapable of moving the flow required in later years without addition of additional compression horsepower at the gas plant. Moreover, the larger line would be capable of transporting increased flow should Inuvik grow faster than expected. (An additional gas processing train would be required at the gas plant if demand exceeded 12 MMcfd). The six-inch line is capable of moving the required flow at the plant outlet pressure of 800 psi and was selected for that reason and because the incremental cost over 4-inch is small.

The pipe specification selected was as follows:

CSA Class II, Grade 46
6.625″ 0.0. by .141″ wall thickness

Based on the low population density in the area, a design factor of 0.72 was used giving a MAOP of 1410 psig. Intermediate valves have not been included since they would be inaccessible much of the year without costly access facilities. Grade 46 pipe should provide excellent weldability, even under adverse weather conditions. The wall thickness selected is the minimum Canuck Engineering would recommend for adequate mechanical strength during handling and construction and for avoidance of thin wall welding problems such as burn-through. A wall thickness of .156" would provide still better weldability, mechanical strength and a larger margin for corrosion resistance.

5.0 CAPITAL COSTS

5.1 Capital Costing Approach

The material and construction costs for the Inuvik gas supply project were based on the fundamental designs described previously and are based on the judgment of the consultant regarding process selection, construction practices, production rates, crew sizes and the other aspects of the project. The standards adopted are considered adequate for an initial feasibility analysis but may be subject to revision in the light of more data which may suggest variations in process and/or construction methods. The costs presented are based on 1980 actual or estimated costs.

5.2 Material Costs

Material costs as used for the cost estimates were based on published prices, quotes or estimating prices obtained from suppliers. Costs used were F.O.B. Western Canada with most items including Federal Sales Tax. All costs are expressed in 1980 dollars. F.S.T. was not included as materials used for production and gathering facilities which are exempted from F.S.T.

5.3 Construction Costs

The estimated construction costs cover all labour, equipment, construction consumables, small tools and supplies and are representative of actual costs to a contractor. The cost of contractor's administration, general overhead and profit was assumed as 20% of construction cost excluding cost of equipment.

Crew sizes and manhours required to complete construction within a stipulated construction schedule, were established based on Canuck Engineering Ltd.)s experience.

Labour classifications and day rates were based on the Pipe Line Contractors' Association of Canada published values for the Northwest Territories. Effective hourly rates are based on a 7-day 84-hour week.

An effective hourly rate was developed for ail trades to enable total direct labour costs to be calculated for all crews. The following is the basis of this development:

Union Hourly Rate (based on 40 hours)	+	Payroll Burdens (18%)	x	Overtime Factor (1.26)	+	Union Benefits	=	Effective Hourly Rate

Payroll burdens were estimated at 18% as follows:

Vacation Pay	10%
Workers' Compensation	4%
C.P.P.	1%
U.I.C.	2%
Accident Insurance	1%
	18%

The overtime factor of 1.26 was based on a 7-day week, 12 hours per day. The 84 hours per week consisted of 40 straight-time hours and 44 overtime hours for a total of 106 equivalent straight-time hours. Union benefits include Health and Welfare, Pension Plan, Training Fund, and the Pipeline Industry Promotion Fund.

5.4 Equipment Costs

Equipment costs were calculated based on the current purchase price. Salvage value for the equipment after job completion was assumed as 50% of the original purchase price. Camp costs were based on data received from the supplier. Equipment for the pipeline was based on the standard "effective rental charge" included in the contractor's bid.

5.5 Logistics Costs

Shipping costs were calculated for cargo from Edmonton to Inuvik using rail transport to Hay River and barging down the Mackenzie River to the staging area at Inuvik. Staging at Hans Bay was rejected because of the limited shipping season and the absence of dock facilities. Transportation costs of $135.00/ton were used including stockpiling and handling. Air support costs for personnel and perishable supplies have been allowed for during the active construction period.

5.6 Cost of Ancillary Facilities

Cost of purchasing and site erection of construction camp were classified as costs of ancillary facilities. These costs were estimated at S8,000 per man. These costs are based on prefabricated buildings of the general type as provided by Atco. No allowance was made for recovery of the camp after job completion, nor were any costs allowed for removal of the camp facilities. Cost of fuel storage and life support systems such as potable water were also classified as cost or ancillary facilities.

Operating and maintenance vehicles and equipment were also included under this heading. O & M buildings were costed under the wellhead and plant categories.

5.7 Capital Cost Summaries

A direct capital cost breakdown for each major facility is included in Tables 5.7.1 to 5.7.8. Our overall project summary is included in Table 5.7.9. These capital cost summaries include indirect capital costs as a percentage of direct capital costs as follows:

Indirect Capital Cost Item	Percent of Direct Cost
Per Permit and Application Engineering	2%
Engineering	6%
Owner's Management and Overhead	2%
O & M prior to Service	¼%
Chemicals, Process Fluids and Line Pack	2%
Interest during Construction (6 months @ 12%)	6%
Contingency	10%
TOTAL INDIRECT COSTS (as per percentage of direct costs)	28¼%

TABLE 5.7.1

PRODUCTION AND INJECTION WELL DIRECT CAPITAL COSTS

Direct Capital Costs	$ 1980 x 1000
Gas Well	4,000
Gas Well	4,000
H_2O Well	4,000
HC Well	4,000
Total Direct Capital Cost	16,000

NOTE Well direct capital costs have been quoted at $4,000,000 each which is the mid-point of the range $3 million to $5 million estimated by Gulf.

TABLE 5.7.2

WELLHEAD FACILITIES DIRECT CAPITAL COSTS

Item	Gas Well	$1980 x 1000 H_2O ‘e’‘	HC Well
Land	1	1	
Site Work	52	52	52
Buildings	93	93	93
Building Systems (Light, Heat, etc.)	18	18	18
Life Support (Water, Sewage, etc.)	26	26	26
Test Manifold and Separator	25	0	0
Metering	22	16	16
Hot Oil System	35	35	35
Propane Refrigerant System	45	45	45
Inhibitor and Chemical Injection	15	15	15
Reinfection Pumps	0	27	27
Flare Systems	35	0	35
Liquid Storage	30	30	30
Controls and Communication	25	25	25
TOTAL DIRECT CAPITAL COSTS	432	383	418

TOTAL DIRECT CAPITAL COSTS
FOR ALL WELLS 1665

TABLE 5.7.3

PRODUCTION FACILITIES DIRECT CAPITAL COSTS

Item	$1980 x 1000
Land	1
Flowline System to 4 Wells	400
Site Work	353
Buildings and Foundations	480
Building Systems (Includes Utilidors)	192
Turbomachinery	1480
Electric Generation and Distribution	388
Vessels, Boilers and Exchangers	511
Liquid Storage and Transfer	185
Cooling	180
Piping and Valves	560
Instrumentation, Communication and Control	175
Other (Flare, Fire, Metering, etc.)	450
TOTAL DIRECT MATERIAL COST	4945
Labour	2160
Fuel	30
Construction Consumables	126
Contractor's Overhead and Profit @ 20%	463
Equipment @ 50% Cost Recovery	320
TOTAL DIRECT INSTALLATION COST	3099
Camp Including Ancillary Life Support and Transport Facilities	480
Camp Operation	194
TOTAL CAMP CAPITAL COST	674
TOTAL DIRECT CAPITAL COSTS	8729

'ABLE 5.7.4

OPERATING CAMP DIRECT CAPITAL COSTS

Item	$1980 x 1000
Land	1
Camp Including Ancillary Life Support	240
TOTAL DIRECT CAPITAL COSTS	241

TABLE 5.7.5

LOGISTICS AND TRANSPORT FACILITIES

DIRECT CAPITAL COSTS

Item	$1980 x1000	
Land	1	
Helipad - Site Work	35	
Building	40	
Lighting and Communication	50	
Helipad Total Direct Capital Costs		126
Roads	391	
Stockpiling and Staging Sites	83	
TOTAL DIRECT CAPITAL COSTS	600	

TABLE 5.7.6

OPERATING AND MAINTENANCE FACILITIES

DIRECT CAPITAL COSTS

Item	$1980 x1000
Equipment and Tools	200
Vehicles	150
TOTAL DIRECT CAPITAL COSTS	350

TABLE 5.7.7
INUVIK TOWN GATE METER STATION
DIRECT CAPITAL COSTS

I tern	$1980
Land	1,000
Site Preparation	6,951
Concrete, Pilings and Foundations	1,000
Buildings and Structural Steel	4,800
High Pressure Piping	17,672
Utility Systems	8,000
Instrumentation and Control	25,238
Electrical (Supply and Install)	10,000
Other	1,183
Contracts	17,700
TOTAL DIRECT CAPITAL COSTS	95,544

NOTE

The connecting medium pressure distribution line to the NCPC facility has a direct capital cost estimated at $30,000.

TABLE 5.7.8

UNESCALATED COSTS $ 000's

TOWN OF INUVIK -- PARSONS LAKE TO INUVIK -- 6" GAS FOR 14.0

[illegible] ENG. LTD--PIPELINE INVESTMENTS--BASE 1980 [illegible]

SEGMENT NO. ONE KMP .00 to KP 41.07

EXPENDITURE PERIOD	1 1980 WINT	2 1980 SUMR	3 1981 WINT	4 1981 SUMR	5 1982 WINT	6 1982 SUMR	7 1983 WINT	8 1983 SUMR	9 1984 WINT	10 1984 SUMR	CUMULT. COST
LAND COSTS											
EASEMENTS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
ACQUISITIONS	0.	0.	2.	0.	0.	0.	0.	0.	0.	0.	[illegible]
DAMAGES	0.	0.	2.	0.	0.	0.	0.	0.	0.	0.	2.5
TOTAL	0.	0.	5.	0.	0.	0.	0.	0.	0.	0.	4.5
MATERIAL COSTS											
CLASS I PIPE	0.	0.	803.	0.	0.	0.	0.	0.	0.	0.	803.4
CLASS II PIPE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
CLASS III PIPE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
SPECIAL PIPE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
COATINGS	0.	0.	154.	0.	0.	0.	0.	0.	0.	0.	153.6
VALVES,FITTINGS,ETC.	0.	0.	73.	0.	0.	0.	0.	0.	0.	0.	72.7
CONCRETE WEIGHTS	0.	0.	99.	0.	0.	0.	0.	0.	0.	0.	98.7
FREIGHT ON MATERIALS	0.	0.	157.	0.	0.	0.	0.	0.	0.	0.	157.1
TOTAL	0.	0.	1286.	0.	0.	0.	0.	0.	0.	0.	1285.6
CONSTRUCTION COSTS											
CLEARING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
CAMP COSTS	0.	0.	271.	0.	0.	0.	0.	0.	0.	0.	271.1
LINE COSTS	0.	0.	2600.	0.	0.	0.	0.	0.	0.	0.	2600.3
STOCKPILING	0.	0.	42.	0.	0.	0.	0.	0.	0.	0.	41.7
RIVER CROSSING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
CONCRETE WEIGHTS	0.	0.	89.	0.	0.	0.	0.	0.	0.	0.	88.8
APPURTENANCES	0.	0.	109.	0.	0.	0.	0.	0.	0.	0.	108.8
DRILL AND BLAST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
BORROW AND FILL	0.	0.	65.	0.	0.	0.	0.	0.	0.	0.	65.1
RE-VEGETATION	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	.0
SPECIAL CONDITIONS	0.	0.	22.	0.	0.	0.	0.	0.	0.	0.	21.7
TOTAL	0.	0.	3198.	0.	0.	0.	0.	0.	0.	0.	3197.5
ENGINEERING COSTS											
SUPERVISION	0.	0.	[illegible]	0.	0.	0.	0.	0.	0.	0.	[illegible]
SURVEYING	0.	0.	185.	0.	0.	0.	0.	0.	0.	0.	184.6
CONST. INSPECTION	0.	0.	306.	0.	0.	0.	0.	0.	0.	0.	[illegible]
MATER. INSPECTION	0.	0.	31.	0.	0.	0.	0.	0.	0.	0.	30.8
TOTAL	0.	0.	613.	0.	0.	0.	0.	0.	0.	0.	612.4
TOTAL SEGMENT COST	0.	0.	5101.	0.	0.	0.	0.	0.	0.	0.	5101.[illegible]

TABLE 5.7.9

PARSONS LAKE GAS SUPPLY SYSTEM

TOTAL DIRECT CAPITAL COSTS

Direct Capital Cost Item		$1980 x 1000
Wells		16,000
Wellhead Facilities		1,665
Flowline Systems		400
Processing Plant		8,329
Operating Camp		241
Operating and Maintenance Facilities		350
Logistics and Transportation Facilities		600
Pipeline Facilities		5,101
Town Gate Meter Station		95
Medium-Pressure NCPC Distribution Line		30
TOTAL DIRECT CAPITAL COSTS		32,811
Indirect Capital Cost Item		
Pre-Permit Engineering	@ 2%	656
Engineering	@ 6%	1,969
Owner's Management and Overhead	@ 2%	656
Interest During Construction (for 6 months @ 6%)	@ 12%	1,969
O & M prior to Service	¼%	82
Process Fluids and Line Pack	2%	656
Contingency	10%	3,281
	28¼%	9,269
TOTAL CAPITAL COST		42,080

6.0 OPERATING AND MAINTENANCE COSTS

6.1 General

In developing operating and maintenance costs, it is assumed that Gulf would act as operator for the combined facilities. Gulf would almost certainly insist on operating the well production facilities. It would result in extra expense for an additional crew to be used for pipeline operation. Primary facility operation would be from the gas plant control centre. The on-site crew would be used for minor day-to-day maintenance with an additional crew brought in for annual maintenance. Maintenance of major equipment, such as turbo-machinery, will be performed on a contract basis.

6.2 Operating Crew

The basic operating philosophy assumes three men at the plant site on a continuous basis. The work schedule is based on a 12-hour day, 7 days per week with partial rotation of men on a weekly basis by helicopter (or vehicle in winter).

6.3 Maintenance Crew

Additional camp accommodation for nine men has been included to provide for an annual regular maintenance crew or for extra men required should well problems develop. If a full service rig was required, it is presumed that extra temporary crew accommodation for that facility would be brought in at that time.

6.4 Operating Supplies

Operating supplies (other than perishables and similar camp supplies) would be brought in annually. These include operating liquids and chemicals such as glycol, make-up refrigerant propane, diesel fuel and corrosion and hydrate inhibition chemicals as well as other supplies such as spare parts and tools.

The principal other operating supply consumed is gas fuel for operation of the plant and wellhead facilities, electric power generation, and heating.

6.5 Other Operating Expenses

Other direct operating expenses include:

(a) insurance and damages
(b) head office expenses
(c) transportation and logistics

6.6 Operating and Maintenance Summary

A summary of expected O & M expense is shown in Table 6.6.1.

TABLE 6.6.1

OPERATING AND MAINTENANCE DIRECT OPERATING EXPENSES

Item		Annual Cost $1980 x 1000
Well Service		
@ $100,000 annually assuming Gulf Service Contract		400
Operating Labour		
Including Benefits	Field	90
	Head Office	48
Additional Maintenance Labour		
Including Service Contracts		75
Personnel Transport		
Helicopter		40
Vehicle		15
Fuels (Heat and Transport)		12
Chemicals and Process Fluids		25
Camp Operation		55
Operating Fuels		328
Other		20
TOTAL ANNUAL DIRECT OPERATING AND MAINTENANCE COSTS		1108

The cumulative effect of these incentives has, in the past, reduced Arctic well cost to as low as ten cents on the dollar. Whilesome of these incentives may not be applicable and others, such as the frontier allowance, may be reduced or eliminated, the effect is still a substantial reduction of actual out-of-pocket costs. The time frame for partial recovery of the capital invested is sufficiently accelerated that present value analysis of the returning cash flows does not radically change the econom c picture.

It is recognized that such cost shar ng would be subject to negotiation on both the amount of the cost to be borne by Inuvik and the mechanism by which the costs would be recovered. Accordingly, and somewhat arbitrarily, it has been assumed that a capital cost contribution of 50% of the well cost would be borne by Inuvik financed by 20-year term debt at 12% interest with uniform annual repayments of principal. Gulf would retain all the tax benefits. This mechanism obviates the difficulty of the town attempting to apply tax incentives against resource income and is consistent with Gulf acting as the systems operator. The Town of Inuvik would bear all the operating expense.

7.2 Processing Facilities

Under this category are grouped the wellhead facilities, flowlines, processing plant, camp and transportation infrastructure including roads and helipads. Conventional financing has been assumed for these facilities as follows:

Debt Financing	12%
Equity Return	15%
Debt/Equity Ratio	80/20
Project Life	20 years
Book Depreciation	5% straight line
Tax Depreciation (Composite Rate)	15%
Tax Rate	46%
Inflation	8%

7.3 Pipeline Facilities

The pipeline facilities including meter stations and other ancillaries are grouped under this heading. Conventional financing has been assumed as follows:

Debt Financing	12%
Equity Return	15%
Debt/Equity Ratio	80/20
Project Life	20 years
Book Depreciation	5%
Tax Depreciation (Composite Rate)	7%
Tax Rate	46%
Inflation	8%

7.4 Cost of Service

Cost of service has been subdivided as occuring from four sources as follows:

(a) Direct cost of gas
(b) Cost of wells
(c) Cost of plant processing
(d) cost of pipeline transportation

This composite rate has been used so that the relative importance of each component may be assessed. It also aids in providing a preliminary indication of the sensitivity of the economic analysis to the assumptions used in deriving it. The component results are shown in Tables 7.4.1 to 7.4.3 and the composite rate is summarized in Table 7.4.4.

TABLE 7.4.1

INUVIK GAS SUPPLY SYSTEM

WELL COST OF SERVICE-50% CONTRIBUTION BASIS

ECONOMIC ANALYSIS - RATE OF RETURN

CASE NUMBER 1
TOTAL HORSEPOWER INSTALLED = 0.
TOTAL LENGTH = 0.000
MAXIMUM THROUGHPUT = 0.

YEAR	AVG. THROUGH PUT MCF/D	TARIFF C/MCF	GROSS REV. M$	OPER. COST M$	BOOK DEPREC M$	DEBT INTRST M$	BT NET OPER S REV. M$	FED. INCOME TAX M$	AT NET OPER. REV. M$
1980	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	2630.0	192.630	1849.2	400.0	505.0	1171.9	-227.8	0.0	-227.8
1982	2670.0	192.630	1877.3	432.0	505.0	1110.2	-170.0	0.0	-170.0
1983	2700.0	192.630	1898.4	466.6	505.0	1048.5	-121.7	0.0	-121.7
1984	2740.0	192.630	1926.5	503.9	505.0	986.9	-69.3	0.0	-69.3
1985	2770.0	192.630	1947.6	544.2	505.0	925.2	-26.8	0.0	-26.8
1986	2810.0	192.630	1975.7	587.7	505.0	863.5	19.5	0.0	19.5
1987	2850.0	192.630	2003.8	634.7	505.0	801.8	62.3	0.0	62.3
1988	2880.0	192.630	2024.9	685.5	505.0	740.2	94.2	0.0	94.2
1989	2930.0	192.630	2060.1	740.4	505.0	678.5	136.2	0.0	136.2
1990	2960.0	192.630	2081.2	799.6	505.0	616.8	159.8	0.0	159.8
1991	3000.0	192.630	2109.3	863.6	505.0	555.1	185.6	0.0	185.6
1992	3040.0	192.630	2137.4	932.7	505.0	493.4	206.3	0.0	206.3
1993	3080.0	192.630	2165.5	1007.3	505.0	431.8	221.5	0.0	221.5
1994	3120.0	192.630	2193.7	1087.8	505.0	370.1	230.7	0.0	230.7
1995	3160.0	192.630	2221.8	1174.9	505.0	308.4	233.5	0.0	233.5
1996	3200.0	192.630	2249.9	1268.9	505.0	246.7	229.3	0.0	229.3
1997	3240.0	192.630	2278.0	1370.4	505.0	185.0	217.6	0.0	217.6
1998	3280.0	192.630	2306.2	1480.0	505.0	123.4	197.8	0.0	197.8
1999	3320.0	192.630	2334.3	1598.4	505.0	61.7	169.2	0.0	169.2
2000	3370.0	192.630	2369.4	1726.3	505.0	.0	138.2	0.0	138.2
TOTAL AVG.	2987.5	192.6	42010.2	18304.8	10100.0	11719.1	1886.3	0.0	1886.3

TABLE A-3

COST OF SERVICE SUMMARY

FOR

NATURAL GAS SUPPLY TO INUVIK FROM YA YA

Component	Contribution to Delivered Cost $MMcf
Field Gas	1.25
Wells (on a 50% capital cost contribution basis)	1.93
Processing Facilities (includes wellhead, flow-line, plant, camp and ancillary facilities)	2.19
Pipeline Facilities (includes pipeline, meter station distribution and ancillary facilities)	3.28
TOTAL COST OF DELIVERED GAS	8.65

NOTES

(1) Based on 100% capture of Inuvik market; NCPC supply only would increase components other than field gas by 25%.

(2) Field gas price has been arbitrarily set near current field prices for southern Canada.

TABLE 7.4.1

YEAR	TANGA INV M$	L FILL +W CAP M$	TOTAL INV. M$	O.S. DEBT M$	NET CASH FLOW M$	ANNUAL RETURN ON INV PCT	CUM NET CASH FLOW M$	NET A CASH FLOW M$	CUM NET A DEBT FLOW M$
1980	10100.0	180.000	10280. 0	10279.9	-10280.0	0.0	-10280.0	-10280.0	-10280.0
1981	0.0	0. 000	0.0	9765.9	277.2	-2.2	-10002.8	-236.8	-10516.8
1982	0.0	0. 000	0.0	9251.9	335.0	-1.7	-9667.7	-178.9	-10695.7
1983	0.0	0.000	0.0	8737.9	383.3	-1.2	-9284.5	-130.7	-10826.4
1984	0.0	0. 000	0.0	8223.9	435.7	-.7	-8848.7	-78.3	-10904.7
1985	0.0	0.000	0.0	7709.9	478.2	-.3	-8370.5	-35.8	-10940.5
1986	0.0	0. 000	0.0	7195.9	524.5	.2	-7846.0	10.5	-10930.0
1987	0.0	0.000	0.0	6681.9	567.3	.6	-7278.8	53.3	-10876.8
1988	0.0	e. 000	0.0	6167.9	599.2	.9	-6679.6	85.2	-10791.5
1989	0.0	0. 000	0.0	5653.9	641.2	1.3	-6038.3	127.2	-10664.3
1990	0.0	0.000	0.0	5139.9	664.8	1.6	-5373.5	150.8	-10513.5
1991	0.0	0.000	0.0	4626.0	690.6	1.8	-4682.9	176.6	-10336.9
1992	0.0	0.000	0.0	4112.0	711.3	2.0	-3971.6	197.3	-10139.5
1993	0.0	0. 000	0.0	3598.0	726.5	2.2	-3245.1	212.5	-9927.0
1994	0.0	0.000	0.0	3084.0	735.7	2.2	-2509.3	221.7	-9705.3
1995	0.0	0. 000	0. 0	2570.0	738.5	2.3	-1770.8	224.5	-9480.7
1996	0.0	0. 000	0.0	2056.0	734.3	2.2	-1036.5	220.3	-9260.4
1997	0.0	0. 000	0.0	1542.0	722.6	2.1	-313.8	208.6	-9051.8
1998	0.0	0. 000	0.0	1028.0	702.8	1.9	389.0	188.8	-8862.9
1999	0.0	0.000	0.0	514.0	674.2	1.6	1063.2	160.2	-8702.7
2000	0.0	0.000	0.0	.0	643.2	1.3	1706.3	129.2	-8573.6
TOTAL AVG.	10100.0	W%. %	10280.0	97659.0	1706.3	.9	1706.3	-8573.6	-8573.6

TABLE 7.4.1

PRESENT VALUE PROFILE / **PI RATIOS**

DISC RATE PCT	PRE INTRST CASH FLOW M$	NET B DEBT CASH FLOW M$	NET A DEBT CASH FLOW M$	EQUITY CASH FLOW M$	TOTAL INV M$	EQUITY INV M$	PRE INTRST FLOW/ TOT INV	B DEBT FLOW/ TOT INV	EQUITY FLOW/ EQUITY INV
0.0	13425.4	1706.3	-8573.6	1706.3	10280.0	.1	1.3	.2	16598.5
5.0	5652.5	-3088.0	-9651.7	628.2	10280.0	.1	.5	-.3	6110.9
10.0	1310.1	-5569.7	-10159.2	120.7	10280.0	.1	.1	-.5	1173.9
15.0	-1311.5	-6956.6	-10406.7	-126.8	10280.0	.1	-.1	-.7	-1233.7
20.0	-3005.1	-7787.6	-10529.5	-249.6	10280.0	.1	-.3	-.8	-2427.7
30.0	-4996.4	-8674.3	-10617.5	-337.6	10280.0	.1	-.5	-.8	-3283.6
40.0	-6099.2	-9110.4	-10629.0	-349.1	10280.0	.1	-.6	-.9	-3396.1

DISCOUNTED CASH FLOW RATES OF RETURN

ON TOTAL INVESTMENT PRE DEBT INTEREST 12.20
ON TOTAL INVESTMENT PRE DEBT REPAYMENT 1.40
ON EQUITY INVESTMENT AFT DEBT REPAYMENT 12.00

ALL INVESTMENTS ARE ASSUMED TO BE CONSTRUCTED DURING THE YEAR PRECEDING OPERATION START-UP.
THEY ARE SHOWN AND DISCOUNTED ACCORDINGLY
FOLLOWING PARAMETERS WERE USED IN THE CALCULATION
0 YEARS HOLIDAY ON DEBT REPAYMENT
DEBT REPAYMENT DURING 20 YEARS
STRAIGHT LINE DEPRECIATION OF 5.00 PERCENT FOR BOOK DEPRECIATION
DECLINING BALANCE DEPRECIATION OF 0.00 PERCENT FOR TAX PURPOSES
0. PERCENT EQUITY INVESTMENT
12.000 PERCENT INTEREST ON BORROWED CAPITAL
8.0 PERCENT ESCALATION OF OPERATING COST
ANNUAL MIDPERIOD DISCOUNTING
ANNUAL RETURN ON INVESTMENT CALCULATED ON FULL INVEST MENT

TABLE 7.4.2

* *

INUVIK GAS SUPPLY SYSTEM

PRODUCTION FACILITIES COST OF SERVICE

* *

ECONOMIC ANALYSIS - RATE OF RETURN

CASE NUMBER 1
TOTAL HORSEPOWER INSTALLED = 0.
TOTAL LENGTH = 0.000
MAXIMUM THROUGHPUT = 0.

YEAR	AVG. THROUGH PUT MCF/D	TARIFF C/MCF	GROSS REV. M$	OPER. COST M$	BOOK DEPREC M$	DEBT INTRST M$	BT NET OPER. REV. M$	FED. INCOME TAX M$	AT NET OPER. REV. M$
1980	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	2630.0	218.700	2099.4	220.0	731.3	1355.0	-206.9	-768.0	561.0
1982	2670.0	218.700	2131.3	237.6	731.3	1283.7	-121.3	-577.2	455.9
1983	2700.0	218.700	2155.3	256.6	731.3	1212.4	-45.0	-413.5	368.4
1984	2740.0	218.700	2187.2	277.1	731.3	1141.1	37.7	-266.0	303.7
1985	2770.0	218.700	2211.2	299.3	731.3	1069.8	110.8	-139.4	250.2
1986	2810.0	218.700	2243.1	323.3	731.3	998.5	190.1	-23.9	214.0
1987	2850.0	218.700	2275.0	349.1	731.3	927.1	267.5	78.8	188.7
1988	2880.0	218.700	2299.0	377.0	731.3	855.8	334.8	166.9	167.9
1989	2930.0	218.700	2330.9	407.2	731.3	784.5	415.9	252.7	163.2
1990	2960.0	218.700	2362.8	439.8	731.3	713.2	478.6	322.8	155.8
1991	3000.0	218.700	2394.8	475.0	731.3	641.9	546.6	389.2	157.5
1992	3040.0	218.700	2426.7	513.0	731.3	570.5	611.9	449.0	162.9
1993	3080.0	218.700	2458.6	554.0	731.3	499.2	674.1	502.9	171.2
1994	3120.0	218.700	2490.6	598.3	731.3	427.9	733.0	551.6	181.5
1995	3160.0	218.700	2522.5	646.2	731.3	356.6	788.4	595.4	193.1
1996	3200.0	218.700	2554.4	697.9	731.3	285.3	840.0	634.6	205.3
1997	3240.0	218.700	2586.3	753.7	731.3	214.0	887.4	669.7	217.7
1998	3280.0	218.700	2618.3	814.0	731.3	142.6	930.3	700.7	229.7
1999	3320.0	218.700	2650.2	879.1	731.3	71.3	968.5	727.8	240.7
2000	3370.0	218.700	2690.1	949.5	731.3	0.0	1009.4	754.7	254.7
TOTAL AVG.	2987.5	218.7	47695.7	10067.6	14626.0	13550.5	9451.6	4608.5	4843.1

TABLE 7.4.2

YEAR	TANCA INV M$	L f ILL +W CAP M$	TOTAL INV. M$	O.S. DEBT M$	NET CASH FLOW M$	ANNUAL RETURN ON INV PCT	CUM NET CASH FLOW M$	NET A CASH FLOW M$	CUM NET A DEBT FLOW M$
1980	14626.0	232.000	14658.0	11886.4	-14858.0	0.0	-14858.0	-14858.0	-14858.0
1981	0.0	0.000	0.0	11292.1	1292.3	3.8	-13565.7	698.0	-14160.0
1982	0.0	0.000	0.0	10697.8	1187.2	3.1	-12378.4	592.9	-13567.1
1983	0.0	0.000	0.0	10103.4	1099.7	2.5	-11278.7	505.4	-138.61.7
1984	0.0	0.000	0.0	9509.1	1035.0	2.0	-10243.7	440.7	-12621.0
1985	0.0	0.000	0.0	8914.8	981.5	1.7	-9262.1	387.2	-12233.7
1986	0.0	0.000	0.0	8320.5	945.2	1.4	-8316.8	351.0	-11882.7
1987	0.0	0.000	0.0	7726.2	920.0	1.3	-7396.9	325.6	-11557.1
1988	0.0	0.000	0.0	7131.8	899.2	1.1	-6497.6	304.9	-11252.2
1989	0.0	0.000	0.0	6537.5	894.5	1.1	-5603.2	300.2	-10952.0
1990	0.0	0.000	0.0	5943.2	887.1	1.0	-4716.1	292.8	-10659.3
1991	0.0	0.000	0.0	5348.9	888.8	1.1	-3827.3	294 s 4	-10364.8
1992	0.0	0.000	0.0	4754.6	894.2	1.1	-2933.1	299.9	-10065.0
1993	0.0	0.000	0.0	4160.2	902.5	1.2	-2030.6	308.1	-9756.8
1994	0.0	0.000	0.0	3565.9	912.6	1.2	-1117.9	218.4	-9438.4
1995	0.0	0.000	0.0	2971.6	924.4	1.3	-193.5	330.0	-9108.3
1996	0.0	0.000	0.0	2377.3	936.6	1.4	743.1	342.3	-8766.0
1997	0.0	0.000	0.0	1783.0	949.0	1.5	1692.1	354.7	-8411.3
1998	0.0	0.000	0.0	1188.6	961.0	1.5	2653.1	366.7	-8044.7
1999	0.0	0.000	0.0	594.3	972.0	1.6	3625.1	377.7	-7667.0
2000	0.0	0.000	0.0	0.0	986.0	1.7	4611.1	391.7	-7275.3
TOTAL AVG.	14626.0	232.0	14658.0	112920.8	4611.1	1.6	4611.1	-7275.3	-7275.2

TABLE 7.4.2

############## PRESENT VALUE PROFILE ############################ ########### PI RATIOS ########

DISC RATE PCT	PRE INTRST CASH FLOW M$	NET E DEBT CASH FLOW M$	NET A DEBT CASH FLOW M$	EQUITY CASH FLOW M$	TOTAL INV M$	EQUITY INV M$	PRE INTRST FLOW/ TOT INV	E DEBT FLOW/ TOT INV	EQUITY FLOW EQUITY INV
0.0	11928.4	4611.1	-7275.3	4611.1	14$5E. 0	2971.6	.8	.3	1.6
5.0	3272.6	-2184.8	-9774.3	2112.1	14658.6	2971.6	.2	-.1	.7
10.0	-1506.2	-5801.9	-11108.7	777. ?	14858.0	2971.6	-.1	-.4	.3
15.0	-4375.4	-7900.1	-11889.4	-3.0	14.958. 0	2971.6	-.3	-.5	-.0
20.0	-6228.6	-9214.8	-1 2385.1	-49.3.7	14.E5E .$	2971.6	-.4	-.6	-.2
30.0	-8422 .0	-10719.5	-12966.3	-1079.9	14e5E. 0	2971.6	-.6	-.7	-. 4
40.0	-9659.0	-11539.1	-13295.0	-1408.6	1485E. 0	2971.6	-.7	-.8	-.5

############### DISCOUNTED CASH FLOW RATES OF RETURN###

ON TOTAL INVESTMENT PRE DEBT INTEREST 8.11
ON TOTAL INVESTMENT PRE DEBT REPAYMENT 3.00
ON EQUITY INVESTMENT AFT DEBT REPAYRENT 15. 00

##

ALL INVESTMENTS ARE ASSUMED TO BE CONSTRUCTED DURING THE YEAR PRECEDING OPERATION START-UP.
THEY ARE SHOWN AND DISCOUNTED ACCORDINGLY
FOLLOWING PARAMETERS WERE USED IN THE CALCULATION
0 YEARS HOLIDAY ON DEBT REPAYMENT
DEBT REPAYMENT DURING 20 YEARS
STRAIGHT LINE DEPRECIATION OF 5.00 PERCENT FOR BOOK DEPRECIATION
DECLINING BALANCE DEPRECIATION OF 15.00 PERCENT FOR TAX PURPOSES
20. PERCENT EQUITY INVESTMENT
12.000 PERCENT INTEREST ON BORROWED CAPITAL
8.0 PERCENT ESCALATION OF OPERATING COST
ANNUAL MIDPERIOD DISCOUNTING
ANNUAL RETURN ON INVESTMENT CALCULATED ON FULL INVEST MENT

##

READY .

TABLE 7.4.3

* *

INUVIK GAS SUPPLY SYSTEM

PIPELINE FACILITIES COST OF SERVICE

* *

ECONOMIC ANALYSIS - RATE OF RETURN

CASE NUMBER		1
TOTAL HORSEPOWER INSTALLED	=	0.
TOTAL LENGTH	=	0.000
MAXIMUM THROUGHPUT	=	0.

YEAR	AVG. THROUGH PUT MCF/D	TARIFF C/MCF	GROSS REV. M$	OPER. COST M$	BOOK DEPREC M$	DEBT INTRST M$	BT NET OPER. REV. M$	FED. INCOME TAX M$	AT NET OPER. REV. M$
1980	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0	8.%
1981	2630.0	134.000	1286.3	220.0	329.9	611.3	125.1	-3.1	128.3
1982	2670.0	134.000	1305.9	237.6	329.9	579.1	159.3	27.4	131.8
1983	2700.0	134.000	1320.6	256.6	329.9	547.0	187.1	54.1	133.0
1984	2740.0	134.000	1340.1	277.1	329.9	514.8	218.3	81.3	137.0
1985	2770.0	134.000	1354.8	299.3	329.9	482.6	243.0	104.6	138.4
1986	2810.0	134.000	1374.4	323.3	329.9	450.4	270.8	128.5	142.3
1987	2850.0	134.000	1393.9	349.1	329.9	418.3	296.7	150.8	145.9
1988	2880.0	134.000	1408.6	377.0	329.9	386.1	315.6	169.1	146.5
1989	2930.0	134.000	1433.1	407.2	329.9	353.9	342.0	190.2	151.8
1990	2960.0	134.000	1447.7	439.8	329.9	321.7	356.3	205.1	151.2
1991	3000.0	134.000	1467.3	475.0	329.9	289.6	372.9	220.4	152.4
1992	3040.0	134.000	1486.9	513.0	329.9	257.4	386.6	234.0	152.6
1993	3080.0	134.000	1506.4	554.0	329.9	225.2	397.3	245.6	151.7
1994	3120.0	134.000	1526.0	598.3	329.9	193.0	404.7	255.2	149.5
1995	3160.0	134.000	1545.6	646.2	329.9	160.9	408.6	262.8	145.8
1996	3200.0	134.000	1565.1	697.9	329.9	128.7	408.6	268.2	140.4
1997	3240.0	134.000	1584.7	753.7	329.9	96.5	404.6	271.3	133.2
1998	3280.0	134.000	1604.2	814.0	329.9	64.3	396.0	272.0	124.0
1999	3320.0	134.000	1623.8	879.1	329.9	32.2	382.6	270.2	112.4
2000	3370.0	134.000	1648.3	949.5	329.9	0.0	368.9	267.9	101.0
TOTAL AVG.	2987.5	134.0	29223.7	10067.6	6598.0	6113.1	6445.0	3675.6	2769.3

TABLE 7.4.3

YEAR	TANCA INV M$	LFILL +W CAP M$	TOTAL INV. M$	O.S. DEBT M$	NET CASH FLOW M$	ANNUAL RETURN ON INV PCT	CUM NET CASH FLOW M$	NET A CASH FLOW M$	CUM NET A DEBT FLOW M$
1980	6598.0	105.000	6703.0	5362.4	-6703.0	0.0	-6703.0	-6703.0	-6703.0
1981	0.0	0.000	0.0	5094.3	458.2	1.9	-6244.8	190.0	-6513.0
1982	0.0	0.000	0.0	4826.2	461.7	2.0	-5783.1	193.6	-6319.3
1983	0.0	0.000	0.0	4558.0	462.9	2.0	-5320.2	194.8	-6124.5
1984	0.0	0.000	0.0	4289.9	466.9	2.0	-4853.3	198.8	-5925.7
1985	0.0	0.000	0.0	4021.8	468.3	2.1	-4385.0	200.2	-5725.6
1986	0.0	0.000	0.0	3753.7	472.2	2.1	-3912.8	204.0	-5521.5
1987	0.0	0.000	0.0	3485.6	475.8	2.2	-3437.0	207.7	-5313.8
1988	0.0	0.000	0.0	3217.4	476.4	2.2	-2960.6	208.3	-5105.6
1989	0.0	0.000	0.0	2949.3	481.7	2.3	-2478.9	213.6	-4892.0
1990	0.0	0.000	0.0	2681.2	481.1	2.3	-1997.8	213.0	-4679.0
1991	0.0	0.000	0.0	2413.1	482.3	2.3	-1515.4	214.2	-4464.8
1992	0.0	0.000	0.0	2145.0	482.5	2.3	-1032.9	214.4	-4250.3
1993	0.0	0.000	0.0	1876.8	481.6	2.3	-551.3	213.5	-4036.8
1994	0.0	0.000	0.0	1608.7	479.4	2.2	-71.9	211.3	-3825.5
1995	0.0	0.000	0.0	1340.6	475.7	2.2	403.8	207.6	-3618.0
1996	0.0	0.000	0.0	1072.5	470.3	2.1	874.2	202.2	-3415.7
1997	0.0	0.000	0.0	804.4	463.1	2.0	1337.3	195.0	-3220.7
1998	0.0	0.000	0.0	536.2	453.9	1.8	1791.2	185.7	-3035.0
1999	0.0	0.000	0.0	268.1	442.3	1.7	2233.5	174.2	-2860.8
2000	0.0	0.000	0.0	0.0	430.9	1.5	2664.3	162.8	-2698.1
TOTAL	6598.0	105.0	6703.0	50942.8	2664.2	2.1	2664.3	-2698.1	-2698.1
AVG.									

TABLE 7.4.3

************** PRESENT VALUE PROFILE *************************** *********** PI RATIOS ********

DISC RATE PCT	PRE INTRST CASH FLOW M$	NET B DEBT CASH FLOW M$	NET A DEBT CASH FLOW M$	EQUITY CASH FLOW M$	TOTAL INV M$	EQUITY INV M$	PRE INTRST FLOW/ TOT INV	B DEBT FLOW/ TOT INV	EQUITY FLOW/ EQUITY INV
0.0	5965.4	2664.3	-2698.1	2664.3	6703.0	1340.6	.9	.4	2.0
5.0	1749.0	-713.1	-4137.0	1225.4	6703.0	1340.6	.3	-.1	.9
10.0	-577.4	-2515.4	-4909.5	452.9	6703.0	1340.6	-.1	-.4	.3
15.0	-1968.6	-3558.7	-5358.5	3.9	6703.0	1340.6	-.3	-.5	.0
20.0	-2861.3	-4208.5	-5638.7	-276.3	6703.0	1340.6	-.4	-.6	-.2
30.0	-3905.3	-4941.3	-5955.0	-592.6	6703.0	1340.6	-.6	-.7	-.4
40.0	-4482.2	-5330.4	-6122.5	-760.1	6703.0	1340.6	-.7	-.8	-.6

*************** DISCOUNTED CASH FLOW RATES OF RETURN**

ON TOTAL INVESTMENT PRE DEBT INTEREST 8.48
ON TOTAL INVESTMENT PRE DEBT REPAYMENT 3.63
ON EQUITY INVESTMENT AFT DEBT REPAYMENT 15.05

****

ALL INVESTMENTS ARE ASSUMED TO BE CONSTRUCTED DURING THE YEAR PRECEDING OPERATION START-UP.
THEY ARE SHOWN AND DISCOUNTED ACCORDINGLY
FOLLOWING PARMETERS WERE USED IN THE CALCULATION
0 YEARS HOLIDAY ON DEBT REPAYMENT
DEBT REPAYMENT DURING 20 YEARS
STRAIGHT LINE DEPRECIATION OF 5.00 PERCENT FOR BOOK DEPRECIATION
DECLINING BALANCE DEPRECIATION OF 7.00 PERCENT FOR TAX PURPOSES
20. PERCENT EQUITY INVESTMENT
12.000 PERCENT INTEREST ON BORROWED CAPITAL
8.0 PERCENT ESCALATION OF OPERATING COST
ANNUAL MIDPERIOD DISCOUNTING
ANNUAL RETURN ON INVESTMENT CALCULATED ON FULL INVESTMENT

****

READY .

TABLE 7.4.4

COST OF SERVICE SUMMARY

FOR

NATURAL GAS SUPPLY TO INUVIK FROM PARSONS LAKE

Component	Contribution to Delivered Cost $/MMcf
Field Gas	1.25
Wells (on a 50% capital cost contribution basis)	1.93
Processing Facilities	2.19
(Includes Wellhead, Flowline, Plant, Camp and Ancillary Facilities)	
Pipeline Facilities	1.34
(Includes Pipeline, Meter Station Distribution and Ancillary Facilities)	
TOTAL COST OF DELIVERED GAS	6.71

NOTES

1) Based on 100% capture of Inuvik market; NCPC supply only would increase components other than field gas by 25%.

2) Field gas price has been arbitrarily set near current field prices for southern Canada.

8.0 DISCUSSION

8.1 Technical

Neither the supply source at Ya Ya nor at Parsons Lake is particularly attractive. The Parsons Lake field contains liquids which require fairly extensive processing and CO_2 which is somewhat corrosive. The wells could be subject to problems such as condensate plugging which could be difficult to correct, since access by service rig has a long lead time. The Ya Ya field is shallower, less liquids are produced and there is less CO_2. This could result in less costly or fewer wells.

The Ya Ya field and its properties must be regarded as inadequately defined at this time to justify a commitment to it as a reliable source of supply. In this study, much reliance has been placed on the Gulf assessment of production techniques; alternates such as "pulse flowing" of the wells have not been examined.

The process plant design is clearly dependent on the quality and volume of gas produced from the wells. A conventional plant design utilizing only dewpoint control and containing no CO_2 elimination monoethanolamine loop, liquid topping plant or sulphur removal process. It should be emphasized that if such additional processing facilities are required, gas plant cost would increase markedly.

Capital costs have been based on a reasonably conservative approach, but a detailed analysis of local conditions would be required as an input for actual design and construction. Operating and maintenance costs have been based on a single operator, Gulf, for all facilities. Multiple operators, such as Gulf for production and Inuvik for pipeline, would probably result in higher costs.

The overall designis based on providing a reasonable degree of security of supply by basing the designs on commonality of equipment sizes and types, and sparing and redundancy for essential equipment. However, to effect cost reductions, additional facilities have been eliminated such as:

(a) on-site service rig to eliminate well difficulties;
(b) all-weather gravel roads to Inuvik;
(c) an airstrip suitable for non-hovering aircraft

8.2 Economic

A relatively "no-frills" design has been adopted to keep capital and operating costs within reasonable bounds. Total capture of the Inuvik market has been assumed although no distribution or conversion costs have been assumed. Data on the supply fields is, in some respects, limited. Although much Arctic experience has been accumulated during recent years, Arctic construction projects must still be viewed as having higher associated risks of either unforeseen construction difficulties or cost overruns compared with southern projects. It should be recognized that these factors could result in a higher cost of facilities than this study projects.

The present study forecasts a cost of gas supplied to Inuvik considerably higher than the present energy supply using liquid fuels from Norman Wells. To make the natural gas supply economically competitive with the present supply would require a sharing of costs with other parties such as Gulf or the Federal Government or Territorial Government. The governments may wish to recover some of the foregone taxes that have subsidized northern exploration or, alternatively, may wish to encourage northern urban development by further subsidies either to the operator or the Town of Inuvik.

8.3 Overview

Despite the use of designs that incorporate few frills, the gas supply economics must be regarded as marginal at best. The security of supply is not sufficiently great to justify sole reliance on that source; a standby reserve of the present liquid fuels should be retained. It should be noted that in preliminary discussions Gulf expressed the view that the project was unattractive from a commercial viewpoint.

Alternative energy sources, such as hydroelectric power or a major pipeline could become available in future and these would probably be more attractive energy sources from a viewpoint of both security and cost.

In addition, present national oil and gas policy is in a state of flux and, when resolved, may alter the economic picture vis-a-vis oil, gas or other alternatives.

9.0 CONCLUSIONS

(a) Gas demand for the Town of Inuvik has been predicted for a variety of situations and the slow-growth scenario with complete market capture has been adopted as the basis for study.

(b) Gas supply from the Ya Ya and Parsons Lake fields has been investigated. It is concluded that although the Ya Ya field is superficially more attractive, insufficient data is available to justify a commitment to it as a sole source of supply. While supply from the Parsons Lake field may incur problems, it is considered a feasible alternate.

(c) Preliminary design of facilities has been carried to the point where reliable capital and operation cost estimates can be prepared. Design is predicated on a "no-frills" approach using the lowest cost facilities consistent with a minimum acceptable level of performance.

(d) A construction plan outline has been developed on the basis of the designs adopted assuming an optimistic construction schedule.

(e) Capital and operating cost estimates have been prepared on the basis of the designs adopted.

(f) Cost of service estimates have been prepared on the basis of the capital and operating costs and the financial parameters.

(9) Overall project economics indicate that gas supply is not competitive with the present energy supply unless some outside agency assumes much of the cost.

(h) Alternative energy sources may become available in future and the probability and attractiveness of these alternatives should be examined before Inuvik commits itself to an independent gas supply. Additional studies would be required if gas supply from Ya Ya or Parsons Lake is pursued.

APPENDIX 1

ANALYSIS OF ALTERNATE
GAS SUPPLY FROM YA YA FIELD

For the alternative case of gas supply from the Ya Ya Field the following assumptions have been made:

(1) well cluster configuration and costs similar to the Parons Lake case;

(2) plant configuration and costs similar to the Parsons Lake case;

(3) pipeline costs proportional to the increased length of the line plus the additional cost of crossing the Mackenzie River;

(4) metering and distribution costs similar to the Parsons Lake case; and

(5) O & M costs similar to the Parsons Lake costs.

Based on these assumptions the capital costs for the YaYa alternative are shown in TABLE A-1, the O & M costs in TABLE A-2 and the cost of service in TABLE A-3.

TA8 LE A-1

YA YA GAS SUPPLY SYSTEM
TOTAL CAPITAL COSTS

DIRECT CAPITAL COSTS:

	$1980 x 1000
Wells	16,000
Well head Facilities	1,665
Flowline Systems	400
Processing Plant	8,329
Operating Camp	241
Operating and Maintenance Facilities	350
Logistics and Transportation Facilities	600
Pipeline Facilities	15,331
Town Gate Meter Station	95
Medium-Pressure NCPC Distribution Line	30
TOTAL DIRECT CAPITAL COSTS	43,041

INDIRECT CAPITAL COSTS:

Item		$1980 x1000
Pre-Permit Engineering	@ 2 %	861
Engineering	@ 6 %	2,582
Owner's Management and Overhead	@ 2 %	861
Interest During Construction (for 6 months @ 6%)	@ 12 %	2,582
O & M Prior to Service	@ ¼%	108
Process Fluids and Line Pack	@ 2 %	861
Contingency	@ 10 %	4,304
TOTAL INDIRECT CAPITAL COSTS	@ 28¼%	12,159

TOTAL CAPITAL COST 55,200

TABLE A-2

OPERATING AND MAINTENANCE DIRECT OPERATING EXPENSES

Item	Annual Cost $1980 x 1000
Well Service:	
@ $100,000 annually, assuming Gulf Service Contract	400
Operating Labour:	
Including Benefits - Field	90
- Head Office	48
Additional Maintenance Labour:	
Including Service Contracts	75
Personnel Transport:	
Helicopter	40
Vehicle	15
Fuels (Heat and Transport)	12
Chemicals and Process Fluids	25
Camp Operation	55
Operating Fuels	328
Other	20
TOTAL ANNUAL DIRECT OPERATING AND MAINTENANCE COSTS	1.108