Proposal For A Tuktoyaktuk Gas Project
Mining/oil/energy, Nwt Gas Industry
Date of Report: 1986
Author: Inuvialuit Petroleum Corporation
Catalogue Number: 6-2-7

6-2-7
CS

PROPOSAL FOR A
TUKTOYAKTUK GAS PROJECT

INUVIALUIT PETROLEUM CORPORATION

FEBRUARY, 1986

PROPOSAL FOR A

TUKTOYAKTUK GAS PROJECT

TABLE OF CONTENTS

APPENDIX 2.	Schedule "C" of the Oil and Gas Concession Agreement for the Areas Within the Tuktoyaktuk 7(1) (A) Lands: Gas Purchase Contract.
APPENDIX 3.	Feasibility Stage Plan, Tuktoyaktuk Gas Project, (Inuvialuit Petroleum Corporation.)
APPENDIX 4.	Preliminary Assessment of Tuktoyaktuk Regional Natural Gas Supply System. (R.T.M. Engineering Ltd. July, 1985)
APPENDIX 5.	Notes Re Tuk Gas and Refining. (R.T.M. Engineering Ltd. September, 1985)
APPENDIX 6.	Tuktoyaktuk Gas Pipeline Study. (Canuck GIE Engineering Ltd.December, 1985)
APPENDIX 7.	Preliminary Market Study for a Natural Gas Project in Tuktoyaktuk. (Bogach Associates Ltd. January, 1985)
APPENDIX 8.	Guidelines for Distribution Applicants in the Matter of an Application for a Franchise to Distribute Natural Gas in the Town of Hay River, NWT . (Public Utilities Board of N.W.T.)
APPENDIX 9.	Tuktoyaktuk Gas Supply Scoping Study (R.T.M. Engineering Ltd. January, 1986)
APPENDIX 10.	Tuktoyaktuk Gas Pipeline Study: Supplementary Reports for Harbour Crossing and Tuktoyaktuk to Inuvik Line. (Canuck GIE Engineering Ltd. January, 1986)

1. SUMMARY

The Inuvialuit Petroleum Corporation (IPC) is developing a project to supply Tuktoyaktuk with natural gas from a shallow formation discovered by recent wells drilled by ESSO et al near the community. The proposed gas project will consist of the following components:

1) The completion of two production wells by ESSO et al, and

2) The installation of gathering lines, a glycol plant (to remove water from the gas), a 4 inch pipeline from the field to Tuktoyaktuk, a terminal in Tuk, a propane/air mixture plant (as a stand-by), and a distribution system to residential and commercial users as well as the oil and transportation company bases and NCPC. All of these facilities will be owned and operated by the IPC.

The IPC has carried out a number of preliminary studies that indicate the economic viability of the project. The IPC has also initiated discussions with regulatory and other agencies with the objective of obtaining a gas franchise for the Tuk area, and the approvals required to build a gas transmission and distribution system.

The project is subject to the results of the 1985/86 drilling season. Although gas has been discovered, the characteristics of the present gas zones are not suitable for the gas project. Acceptable gas reservoirs remain to be identified and may not be found. However, the IPC is proceeding with technical and economic studies so that a go/no go decision on the project can be made as soon as possible after a possible discovery of acceptable reservoirs during the next three months.

A scoping study (cost shared by the IPC and ESSO) has been carried out to narrow alternatives in certain areas and to define the technical bases for the system. Prior studies by the IPC have investigated markets in some detail, as well as most system parameters. These studies have indicated that natural gas can probably displace most fuels used for heating and power generation in the Tuk area. IPC studies are now also looking at the possibility of using power generated with natural gas in Tuktoyaktuk to supply all or part of the electricity needs of Inuvik.

A Feasibility Stage has been defined for the project to be carried out during the months of March and April 1986. By May 15, 1986, the IPC hopes to have sufficient information from ESSO'S drilling activities and its own studies to make a go/no go decision on the project.

The timing is primarily set by limitations on transportation in the Arctic. The large pipeline needed for the transmission line must be moved north by barge before freeze up this year in order to meet the target start up date of 1987. Field and terminal modules and distribution piping are also needed before break-up in 1987. ESSO must be notified by July 1 in order to carry out well completions over the winter of 1986/87 to allow start-up in 1987. Any delay in this schedule will delay the project by one full year.

It is hoped that the regulatory requirements (permits and hearings) for this relatively small system can be synchronized with this schedule. It is unlikely that a go/no do decision can be taken without the principal approvals being in place.

This proposal is being presented to all of the relevant agencies in order to start the process of obtaining the franchise agreement and the various approvals required. It summarizes the work done to date and indicates further work planned as part of the feasibility studies. The main studies carried out to date are attached as Appendices and referred to in the proposal.

The proposal summarizes the concepts in the following form:

--Gas Supply

--Proposed Service Area

--System Design and Construction

--Market Estimates

--Capital Expenditure Forecasts

As further studies are completed, the information supplied on each of these subjects will be modified and expanded and new information added in order to conform to the requirements of all regulatory bodies (see for example, Appendix 8: "Guidelines for Distributor Applicants in the Matter of an Application for a Franchise to Distribute Natural Gas in the Town of Hay River, NWT.")

2. GAS SUPPLY

The proposed system to supply natural gas to Tuktoyaktuk, is outlined in Figure 1 and is discussed under the following topics:

--source of the gas

--field facilities

--pipeline

--distribution

-

--appliances

--service

--new customers

2.1 SOURCE OF GAS

Natural gas for local use would be produced from relatively shallow Tertiary gas rich formations in the West Tuk or Mayogiak fields. These formations appear to contain appreciable reserves. The gas is almost entirely methane--the lightest hydrocarbon--with no poisonous hydrogen sulphide or other impurity requiring removal, other than traces of water vapour. There are no heavier hydrocarbons present that might tend to separate out in pipelines and equipment.

The gas lies below permafrost and special techniques will be used to insure that wells do not freeze up as the gas rises to the surface.

The pressure of the gas in the formation is approximately 7500 kpa* more than sufficient to move the gas through treating and pipeline facilities to town.

ESSO et al are carrying out a well drilling program in the West Tuk and Mayogiak fields during the 1985/86 drilling season . The results from this drilling program are needed to confirm the required reserves and the location of the production wells.

Possible sources of production are the H-22, D-n, orN-34 wells, where it is possible that gas may be found in shallow formations. A second well will also be used as a source, to

----

*about 1Ø88 psi.

insure a high degree of reliability. Acceptable reservoirs and specific wells have not yet been identified.

Subject to the required reserves being available, the IPC has already concluded an agreement with ESSO et al in order to have a first call for the local use of gas, LPG or condensates (see Appendix 1). A gas purchase contract has already been agreed upon (see Appendix 2) . These agreements provide that ESSO et al will own and operate the production wells and that the IPC will purchase gas at the well-head, before treatment in field facilities.

2.2 FIELD FACILITIES

Only removal of water is required in the field and this will be achieved in a highly reliable, well proven glycol absorption process. There will also be a back-up dehydration system, in case of maintenance or other outage at the glycol system.

Before entering the pipeline to town, the gas must be chilled to approximately -5 degrees C to prevent thawing of the permafrost by the 25 degrees C gas from the glycol system. Normally, air cooling will be used to achieve this, but a refrigeration system will be provided for warm day use.

The well testing and related facilities will be operated in a coordinated manner with automatic shutdown of individual well systems, in case of emergency. But as both wells will normally be in operation, even when a well is shut down there will be no stoppage of gas flow and the remaining well's output will be increased to handle all demands until the other well is again on line.

Preliminary definition of the field facilities was done as part of "Preliminary Assessment of Tuktoyaktuk Regional Natural Gas Supply System" (see Appendix 4) and the Scoping Study (see Appendix 9). Further work will be carried out as part of the feasibility stage (see Appendix 3).

2.3 PIPELINE

As Map 1 shows, the 10-12 km pipeline from the field to town will generally parallel the existing Inuvik-Tuktoyaktuk electricity supply line; except that it will skirt the eastern corner of the Pingo Canada Landmark Site. The 4 inch line will be buried in the permafrost layer, and as noted above, the gas will be chilled to insure that no erosion occurs due to melting ice along the route.

The line will be designed. to Canadian gas pipeline standards with special consideration of permafrost and other local conditions. Canadian pipelines have achieved an enviable record of reliability and such is anticipated here.

Canuck GIE Engineering Ltd. has completed a pipeline study for the IPC (see Appendix 6). The line could be installed during the months of February and March of 1987, with testing and commissioning occuring prior to spring break-up. Technical information on the pipe size and characteristics, material standards used, etc. is given in Appendix 6.

A branch line to service the east side of the harbour, specifically ESSO, is planned (see Appendices 9 and 10).It will probably cross near the proposed Reindeer Point bridge. If the bridge were in place, this would lower the costs of the eastern connection substantially, by over $200,000. Further work on all pipelines will be carried out during the feasibility stage .

2.4 DISTRIBUTION

At the town end of the main pipeline, there will be a terminal where the pressure will be let down to approximately 1000 kpa and odorant will be added. The amount of odorant added will be such as to allow the quick identification of any leaks (as natural gas has no smell). However, not enough is added to create any concern or nuisance in normal operation.

The major customers such as NCPC, DOME and GULF will receive their gas at the 1000 kpa level via buried pipeline, as certain large demand devices require such a pressure level. For heating devices it is expected that large users will convert to dual fuel (gas plus P-50 backup) burners.

It is anticipated that virtually all electricity needed in the region will be generated through use of natural gas in lieu of expensive present P-50 fuel. However, P-50 fueled generators and an inventory of p-50 will be kept available in the unlikely event that gas supply fails.

For commercial and residential customers a buried, low pressure distribution system will be provided. This system will be built as loops whenever possible to allow short sections to be taken out of service, for tying in new customers, for repairs, and to insure maximum reliability. Each customer will have his own regulator and meter.

2.5 APPLIANCES

Many existing heaters will require replacement and other equipment using oil will need to be modified to use gas. Within the project, arrangements will be made to supply and install new appliances and modify others. Appliances will also need to be repaired. (Parts of these services may be subcontracted or handled by others).

2.6. SERVICE

Aside from appliance service, the gas utility operation will carry out all normal new construction and all but the most major repairs, in conjunction with local contractors. A customer relations program will introduce new customers to natural gas and keep all customers up to date on the optimum use of natural gas and new developments in the Tuk system. The staff will work closely with local contractors to insure that gas lines are not touched by general construction operations.

2.7. NEW CUSTOMERS

The entire system is being designed to meet the needs of Tuk for the foreseeable future. Generally, the field and pipeline system are oversized for current demand levels, including the anticipated peak winter needs. New wells and treatment facilities can be added as needed and new distribution lines can also be run as required. Initial distribution lines in residential and commercial areas will be sized to permit new customers along their routes.

3. PROPOSED SERVICE AREA

The proposed gas sytem will provide service to all potential users in the Tuk community site and, with the line across the harbour, to the east side of the harbour, including ESSO'S base.

Preliminary studies concluded that the economics of extending the system to Inuvik were negative, although further consideration will be given to the possibility as the project develops and more data is available.

4. SYSTEM DESIGN AND CONSTRUCTION

While gas pipeline construction in permafrost is far from a normal event, experience has been gained in Canada, Alaska, and the Soviet Union. Much research has been done in the Delta region on oil and gas lines in comparable conditions. Operation of gas distribution systems in the northern parts of the prairie provinces also provide relevant experience. This is not to say that the pipeline system will be completely straight-forward, but rather to say that the challenges are known and will be respected. No major problems have been noted with regard to the construction operations of the proposed system given appropriate geotechnical and other relevent testing and analysis.

COGLA regulations generally set out codes and standards for the portion of the system outside the urban area, referring to other federal and, in a few cases, Alberta codes and standards. Canadian gasfields and pipelines have acheived a very high standard of reliability, and experience gained will be fully utilized, as appropriate.

Generally, federal standards (Canadian Standards Association) will be followed relative to the distribution system, supplemented by provincial standards and other experience as necessary. Where the presence of permafrost requires that modifications be made, such changes will be reviewed with the GNWT and/or federal officials as appropriate.

While winter construction is planned for the main pipelines, summer or winter construction may be used in town. The contractors of the Tuk region have developed considerable expertise in construction in the region, and it is planned that their capabilities will be used to the fullest.

5. MARKET FORECASTS

An assessment of the market for natural gas in the area has already been carried out (see Appendix 7). This study resulted in the following estimates of demand by sector for the initial year of the project, 1987/88.

	000 M3/year 1987/88	Number of Connections
Residential		
Housing Corporation	560	180
Others	70	15
sub total	630	195
Commercial		
Commercial	630	12
Government	483	44
sub total	1113	56
Industrial		
Dome	2814	1
Gulf	1735	1
Esso	1300	1
NTCL	202	1
ATL	73	1
sub total	6124	5
NCPC	2734	1
TOTAL	10601	257

Growth rates for the different sectors are estimated to be approximately as follows:

Residential	2.5%/yr.
Commercial & Gov't	1%/yr.
Industrial	Ø%/yr.
NCPC	4.Ø%/yr.

The annual estimates for gas sales to the different customers are estimated in Table 8 of Appendix 7. For the base case, this forecast assumes that almost all heating and power requirements of the community of Tuktoyaktuk are supplied by gas.

NCPC now supplies the power requirements for the community of Tuktoyaktuk through a 69kv transmission line from Inuvik. The reliability of this line has been deteriorating and NCPC has already been considering adding an additional 1.4MW of capacity and generating all of the power required for the community in Tuk itself. If gas were available at a substantial discount from diesel, this would make generating power locally even more attractive.

Additional work is planned during the feasibility phase to establish peak rates vs average and to determine the rate at which conversions will take place. In all cases, the penetration rates could be expected to be rapid and high if the gas price is attractive and facilities are available for quick and easy conversion. In Tuk, the market is very concentrated in a small number of large users and the Housing Corporation.

The major uncertainty in the market forecast is the future level of oil exploration activity. The type of contracts that can be obtained with the oil and transportation companies will be an extremely important element in the overall viability of the project. Some method must be found to accommodate the risks associated with supplying major users with uncertain future consumption patterns .

6. CAPITAL AND OPERATING COSTS

The following tables summarize the preliminary estimates of costs for the design and construction of the system and for its operation, exclusive of financing costs.

	(millions 1986$)
Capital Costs	
Field Facilities	1.3
Pipeline (Field to Tuk)	2.1
Pipeline across harbour (without bridge)	Ø.8
Distribution	2.3
Appliances	0.4
TOTAL	6.9
Operating Costs	
Field Facilities and Pipelines	0.1
Distribution	0.7
TOTAL	Ø.8

For further details on preliminary cost figures see Appendices 4 and 9. All cost estimates will be thoroughly revised as part of the planned feasibility stage.

7. TIMING

The results of the winter drilling season should be available by March. If pipeline construction were started in March, 1987, the transmission line could be in place by May 1987. The distribution system could also be in place by that time, if regulatory processes do not cause any delays in design and construction. Conversions could be expected to extend over a one or two year period.

8. BENEFITS FROM THE PROJECT

This project will be of benefit to the local population and to governments and private companies in several ways.

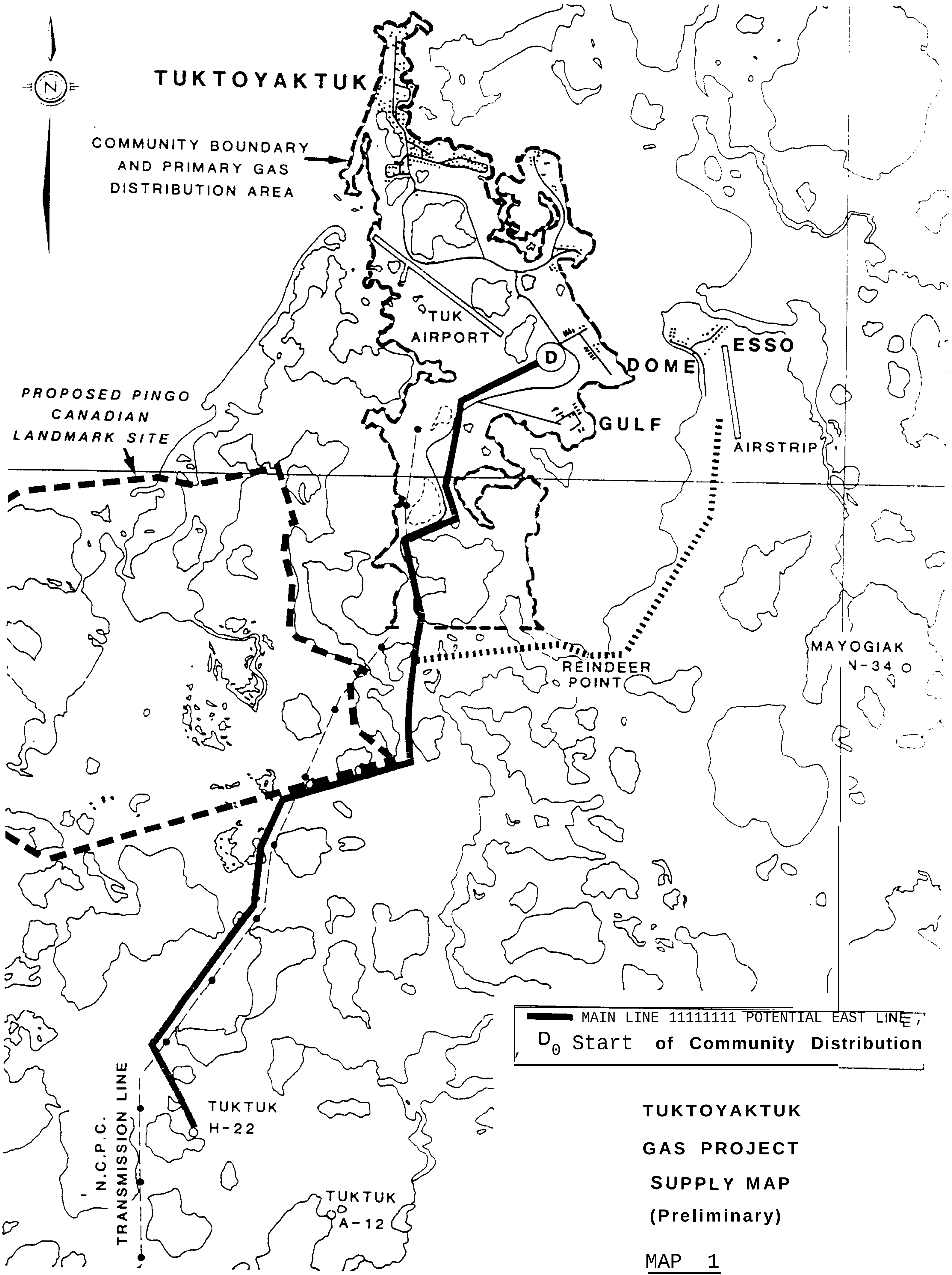
First, the project has the potential to provide lower cost fuel supplies to the community and the bases located at Tuk. The benefits could include lower costs for heating and power generation by private companies and NCPC.

For ESSO et al, the project will provide an outlet for relatively sma11 quantities of natural gas in order to test production procedures, and to obtain better data on reservoir performance and gas quality.

While this type of operation will not need a large staff, the system will provide some employment for managers, administrative staff and skilled labour. Training will be provided to ensure that local people fill these positions to the maximum possible extent. The project will also increase the need for services from other local entrepreneurs and could provide a nucleus for other small industries.

The project will provide an opportunity to test the regulatory procedures of different federal and territorial agencies and their interaction. This could be of considerable benefit to the larger projects that may take place in the future.

In the development of the project, the IPC is placing a high priority on environmental protection. One of the advantages of the project is tat it is confined to a small geographical area where conditions can be carefully observed and monitored. Similar operations on the Alaska North Slope will provide precedents and guidance.



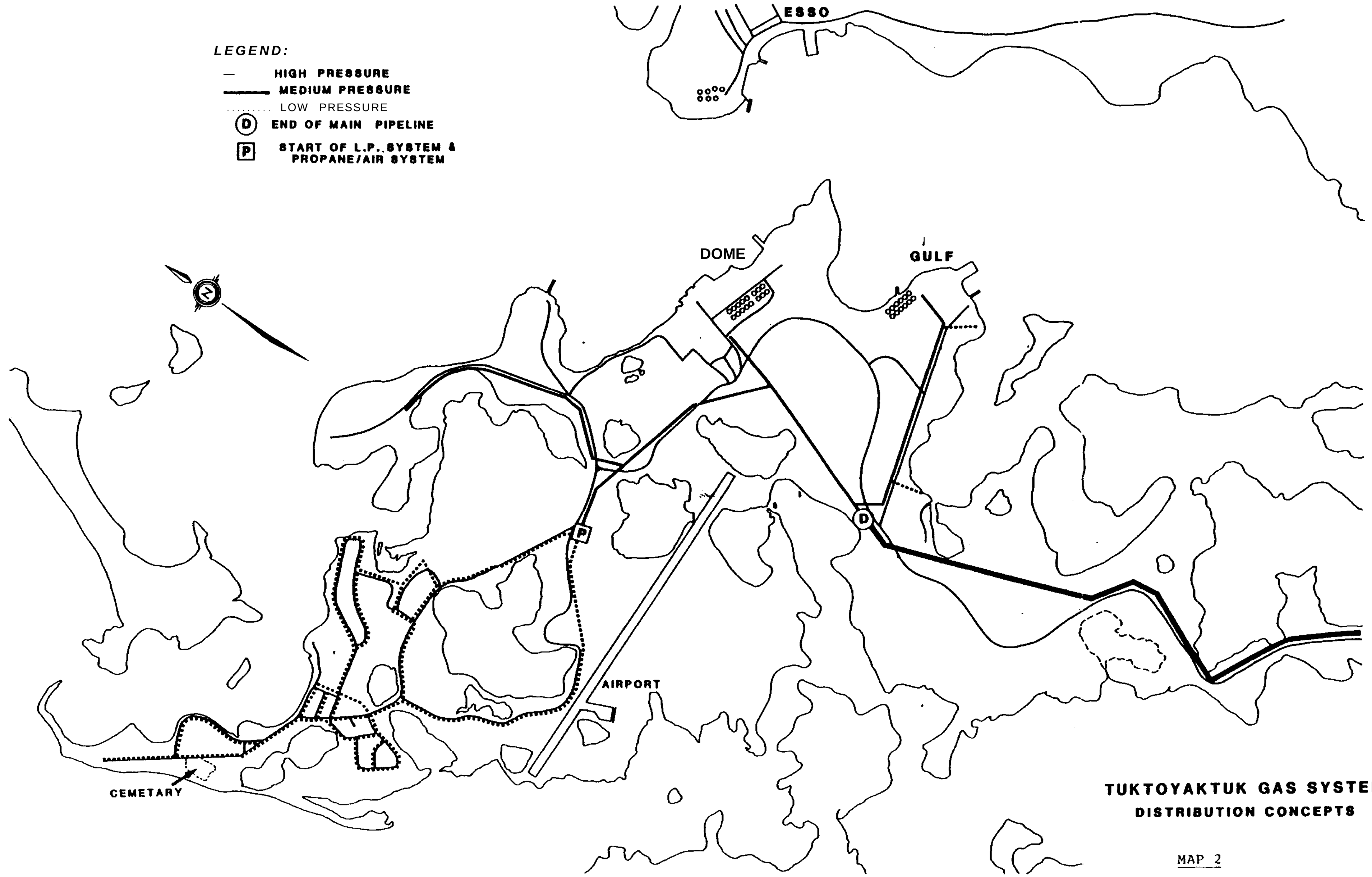
TUKTOYAKTUK

GAS PROJECT

SUPPLY MAP

(Preliminary)

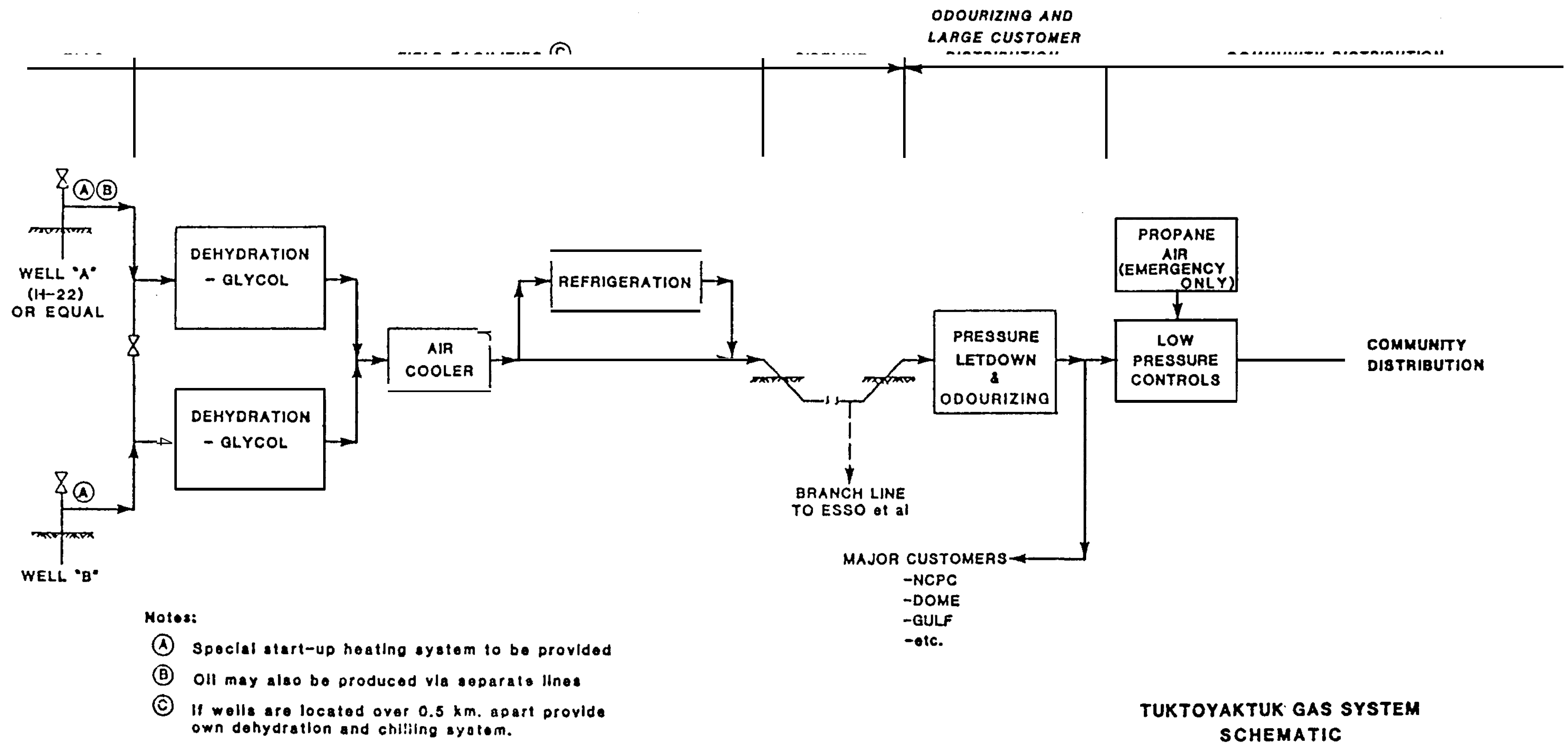
MAP 1



TUKTOYAKTUK GAS SYSTEMS
DISTRIBUTION CONCEPTS

MAP 2

FIGURE 1



TUKTOYAKTUK GAS SYSTEM
SCHEMATIC

time of conversion and the IPC shall assume such Working Interests including all responsibilities for the development, production and sale of Oil. The lands so converted will include only the Spacing Units of the Wells to be produced and the price on which the gross overriding royalty is calculated shall be in accord with Clause 9.6.

35.9 **IPC'S RIGHT TO MAKE INDEPENDENT OPERATION PROPOSALS** - This Article shall not in any manner restrict the ability of the IPC to make Independent Operation Proposals pursuant to Clause 17.3.

ARTICLE XXXVI

LOCAL USE OF GAS, LPG AND CONDENSATES

36.1 **ENTITLEMENT** - The IPC is entitled to a first call for Local Use of Gas, LPG and Condensates upon all or any part of the Non-Associated Gas, Associated Gas, LPG or Condensates produced for its account pursuant to the Inuvialuit Share or any working or other interest that it might have in the Lease Area and upon all or any part of the Non-Associated Gas, Associated Gas, LPG or Condensates that the Lessor is entitled to take in kind pursuant to the Royalty rights set forth in Article XI. These amounts shall include any Non-Associated Gas, Associated Gas, LPG and Condensates that the IPC is entitled to on the basis of any swapping or exchanging arrangements made with respect to the Inuvialuit Share and other IPC Working Interests and the Lessor's Royalty interests in the various Pools in the Lease Area. Where the Local Use of Gas, LPG and Condensates requirements exceed production from the above sources, the IPC shall have the first right, upon giving the Lessee one year's prior notice of its intentions, to purchase from the Lessee any:

(a) Non-Associated Gas or Associated Gas being produced from the Lease Area at a price equal to the Value established in Clause 9.6 plus reasonable transportation costs from the Measurement Point to the Delivery Point; and

(b) LPG or Condensates being produced from the Lease Area at a price to be agreed upon. In their negotiate-, the Lessee and the IPC shall attempt to establish the price for such periods as agreed upon at the highest of:

(i) the Average Price for LPG and Condensates in Edmonton, Alberta less reasonable transportation costs from the Measurement Point to Edmonton, Alberta; or

(ii) the Average Price for LPG and Condensates at any other location less reasonable transportation costs from the Measurement Point to such location; or

(iii) the costs of producing LPG and Condensate with a utility rate of return on investment; or

(iv) the energy equivalent of the highest price at the plant gate for Gas in the Local Market Area.

Where the Lessee and the IPC cannot agree on the price for LPG or Condensates on this basis, the matter shall be referred to arbitration and the arbitrators shall determine what the prices are for items (i), (ii), (iii) and (iv) above and shall establish the price for the LPG on Condensates as the highest of these four prices.

36.2 **NOTICES** - Any notice required to be given pursuant to this Article shall be in writing and shall include an annual schedule of volumes to be purchased.

36.3 **PURCHASE AGREEMENT** - Upon the receipt by the Lessee of the IPC's notice of intention to purchase Non-Associated Gas, Associated Gas, LPG or Condensates pursuant to this Article, the Lessee and the IPC hereto agree to forthwith enter into negotiations for a gas purchase and sale agreement. If agreement cannot be reached, either the Lessee or the IPC may refer any matter under dispute to arbitration and the arbi trators shall resolve the issues presented to them.

36.4 **LESSEE'S PRIOR RIGHT** - The rights of the IPC set forth in this Article are sub ject to the Lessee's prior right to use any Gas, LPG or

Condensates for its Petroleum Operations in the Lease Area when such activities are an integral part of its Petroleum Operations in the Lease Area.

36.5 FLARED GAS - The IPC shall have the right to obtain any Gas, on an as is or where is basis, the Lessee is flaring or intends to flare in conjunction with its Petroleum Operations at no cost to the IPC. However, the right to obtain such Gas may be cancelled by the Lessee upon ninety (90) days not ice to the IPC provided that the Lessee will immediately thereafter use the Gas. At no time will the IPC have any recourse against the Lessee as a result of any reduction or termination of the supply of such Gas occurring as a result of a change in production scheduling made in accordance with good oilfield practice, an equipment failure, an operational upset or any other reason beyond the control of the Lessee. In the event of a reduction or termination occurring, the Lessee shall use its best efforts to promptly notify the IPC of the reduction or termination and make reasonable efforts to restore the supply at an early date. The IX's entitlement to acquire Gas at no cost pursuant to this Clause is subject to the exception that if the Lessee is willing to offer to supply Gas in commercial quantities for local use on a regular basis, then the IPC is obligated to negotiate in good faith with the Lessee in an attempt to reach agreement on a price to be paid by the IPC to the Lessee for the Gas that it would otherwise have been entitled to acquire hereunder at no cost. The IPC shall indemnify and save harmless the Lessee from and against all losses, claims and demands of any nature Whatsoever arising from or in any way connected with the use of such Gas obtained by the IPC pursuant to this Clause 36.5.

36.6 **RETENTION OF WELLS** - Where the Lessee has during the 1985/86 winter drilling season or thereafter identified Acceptable Gas Reservoirs (as hereinafter defined) in at least two Wells that are capable of being completed as Gas Wells in the West Tuk Structure, the Lessee shall keep such Wells in good order for possible completion as part of the project for the supply of Gas to the Tuktoyaktuk Area (the "Gas Project"). Acceptable Gas Reservoirs shall mean:

(a) reservoirs that contain Gas that without the need to remove uneconomic quantities of LPG, Condensates, or sulphur can be used for the distribution of Gas in the Hamlet of Tuktoyaktuk;

(b) reservoirs relating to each of the two Gas Wells that have delivery capabilities sufficiently high to enable the Lessee to commit to deliver a peak rate of at least 40,000 m^3 of Gas per day; and

(c) reserves relating to the Spacing Units for the two Gas Wells that are sufficiently high that the Lessee would be able to commit to deliver a total of at least 80,000,000 m^3 of Gas over the initial term of the Gas Purchase Contract.

36.7 **GAS WELLS** - Wells that can be completed as Gas Wells are Wells in which Acceptable Gas Reservoirs have been found and:

(a) have been drilled as the first five Wells of the Lessee's 1985/86 winter drilling season; and

(b) any other Wells which cannot economically be completed as Oil Wells because of a lack of a substantial Oil reservoir or for other technical reasons.

Where more than two Wells can be maintained for Gas Wells, the Lessee shall keep the two Wells which are nearest to Tuktoyaktuk for the Gas Project.

36.8 **GAS PURCHASE CONTRACT** - The IPC shall have the right, at any time prior to October 1st, 1994 provided this Lease has not been terminated, to require the Lessee to enter into the Gas Purchase Contract (a copy of which is attached hereto as Schedule "C") (the "Gas Purchase Contract") where:

(a) Subject to Clause 36.18, the Lessee has maintained or should have maintained two Gas Wells in accordance with the provisions of this Article; and

(b) the IPC is prepared to commit to take or pay a minimum volume of 7,300,000 m^3 of Gas per year for the years specified in the Gas Purchase Contract;

Provided, however, that where the IPC enters into the Gas Purchase Contract after July 1, 1988, Clause 8.4 of the Gas Purchase Contract shall apply. Furthermore, the Lessee shall take all reasonable efforts to maintain the Gas Wells beyond July 1, 1988. However, here any Well cannot be safely completed beyond that date because of the deterioration of such Well, the obligations of the Lessee with respect to the maintenance of such Well shall terminate. Where none of the Wells can be maintained past a certain point in time, the obligations of the Lessee under this Clause with respect to such Wells shall lapse. Furthermore, the obligation of the Lessee to maintain any Wells beyond July 1, 1988 shall cease upon termination of this Lease.

36.9 **IPC TO PAY ROYALTY** - Where the Lessee and the IPC enter in a Gas Purchase Contract pursuant to Clause 36.18 hereof, the IPC shall be responsible for the payment of Royalty. However, the Royalty will not be offset against the Advanced Royalty paid by the Lessee.

36.10 **ALTERNATE ARRANGEMENTS** - In addition to the obligations defined herein, the IPC and Lessee may in good faith and within the principles herein enunciated, negotiate such additional or alternate arrangements as they subsequently agree will enhance the viability of the Gas Project.

36.11 **RESPONSIBILITY FOR COSTS** - Where the Lessee and IPC enter in a Gas Purchase Contract pursuant to Clause 36.8:

(a) the Lessee shall be responsible for any costs related to the engineering, completion, recompletion where required, repair and maintenance, and operation of the Walls including the costs of the wellheads and any tubing or subsurface equipment, any costs directly relating to the safe operation of the Wells, abandonment and reclamation costs and any liability relating to the Wells;

(b) the IPC shall be responsible for any costs relating to the engineering, equipping, repairing, replacing and maintenance of any pipelines, gathering lines, dehydrators, or any other equipment required for the gathering, processing, transportation and distribution of the gas, removal and reclamation costs, any liability related to the equipment owned by the IPC, and any fees and rentals applicable to the IPC's activities in relation thereto; and

(c) the IPC and the Lessee shall each be responsible for fifty percent (50%) of any costs which relate to both (a) and (b) such as emergency shelter for personnel, communications and access fees and lease rentals for surface leases containing the facilities of both the Lessee and the IPC.

36.12 RESPONSIBILITY FOR OPERATING THE GAS PROJECT - The Lessee and the IPC agree to share the responsibility for operating the Gas Pro ject in the following manner:

(a) The Lessee shall operate the Gas Wells until such time as the operatorship has been transferred to the IPC in accordance with this Clause;

(b) The IPC shall be responsible for the operation of the field facilities up to the point where the Gas enters the Gas transmission pipeline except that the

Lessee at the request of the IPC shall operate these facilities under contract with the IPC for a period not exceeding two years from the date Gas is first delivered. The IPC shall be responsible for the design and engineering of the field facilities for which it is responsible.

(c) The IPC shall operate the Gas transmission line and the community distribution system.

36.13 **SUBSTITUTE WELLS** - Where the Lessee has identified Acceptable Gas Reservoirs but where the Lessee is unable to complete two Gas Wells for the Gas Project for technical reasons or because of exceptionally adverse economic conditions in comparison with original predictions, and the IPC has made the commitment pursuant to Subclause 36.8(b) and has so notified the Lessee prior to July 1st of any Calendar Year, the Lessee shall have the option to provide within the first winter drilling season following such notification the required substitute Well or Wells in order to deliver the minimum volumes in accordance with the Gas Purchase Contract. The Lessee shall so notify the IPC of the Lessee's decision with respect to this option within three months of the IPC notification.

36.14 **OPTIONS OF THE IPC** - Where the Lessee decides not to exercise its options to provide the substitute Well or Wells in accordance with Clause 36.13, the IPC shall have the option to either:

(a) Request the Lessee to drill on behalf of the IPC and at the IPC's cost the substitute Gas Well or Wells within or immediately adjacent to the Spacing Unit (s) of a Well(s) that encountered an Acceptable Gas Reservoir. If drilled, the Lessee shall remain responsible for the costs identified in Subclause 36.11 (a) and (c), and;

(i) If one substitute Well is drilled, all Gas sold under the Gas Purchase Contract shall be sold at sixty percent (60%) of the price stated in the Gas Purchase Contract; and

(ii) If two substitute Wells are drilled all Gas sold under the Gas Purchase Contract shall be sold at twenty percent (20%) of the price stated in the Gas Purchase Cent ract; or

(b) make an Independent Operations Proposal pursuant to a Development operating agreement provided by Clause 17.3 herein; or

(c) in the absence of any such Development operating agreement, request the Lessee to drill a substitute Well in a Spacing Unit which would not be classified as a Delineation or Exploration Well under the Operating Agreement and which would not be immediat ely adjacent to the Spacing Unit of a Well which encountered an Acceptable Gas Reservoir. The proposal to the Lessee shall be made and reviewed and the participants in the Well determined in the same manner as participants are determined pursuant to Article IX of the Joint Operating Agreement. When the participants have been determined they may request the Lessee to drill the substitute Well at the sole cost of the participants. The non-participants shall transfer to the participants one hundred percent (100%) of their interest in the strata within the Spacing Unit above the total depth of the Well. The Participants shall own the Well and shall be responsible for the drilling, completion, equipping and operating costs of the Well.

The foregoing substitute Well penalty provisions shall not be considered a precedent for negotiations with respect to any Development operating agreement.

36.15 REDUCTION OF LESSEE'S OBLIGATIONS UNDER GAS PURCHASE CONTRACT - With respect to Subclauses 36.14 (b) and (c) hereof, where only one substitute Well has been drilled and the IPC also requests the Lessee to enter into the Gas Purchase Contract to supply Gas from one Well that the Lessee has been able to keep and the Lessee is able to do so, the provisions of the Gas Purchase Contract shall be in force except that the Lessee’s obligation to deliver and the IPC's take or pay obligation shall be reduced by fifty percent

(50%). With respect to Subclauses 36.14 (b) and (c) hereof, where two substitute Wells are drilled, the Lessee's obligations with respect to the Gas Project shall cease.

36.16 **RENEWAL OF GAS PURCHASE CONTRACT** - On or before a date two years prior to the termination or the anticipated termination of the Gas Purchase Contract, the IPC shall advise the Lessee whether or not the IPC wishes to enter into negotiations for the renewal of the Gas Purchase Contract and the expected renewal term. If the IPC wishes to negotiate such renewal the Lessee shall forthwith make an estimate of the remaining Gas reserves that it expects will be producible from the Gas Wells after the termination date of the Gas Purchase Contract and of the deliverability of the Gas Wells during the expected renewal term. Where the Lessee and the IPC disagree on the Lessee's pro jetted reserves and/or deliverability, the matter shall be referred to arbi trat ion. .

36.17 **ARBITRATION OF RENEWAL** - Where the Lessee and the IPC agree or where this matter has been resolved through arbitration, the Lessee and the IPC shall forthwith enter into negotiations to renew the Gas Purchase Contract for the expected renewal period or such shorter period as justified by the deliverability and Gas reserves. If one year prior to the termination of the Gas Purchase Contract, agreement on the terms and conditions for renewal has not been reached, the matter shall be referred to arbi trat ion.

36.18 DRILLING ADDITIONAL WELLS - Where the Gas reserves or deliverability of the Gas Wells are found to be insufficient, the Lessee shall have the option to drill such further Wells as may be required for the supply of Gas. Where the Lessee does not wish to drill such Wells and the Lessee has no other supply of suitable Gas which can be economically delivered, the IPC shall have the right to drill such Wells pursuant to Clause 17.3. In the absence of the Development operating agreement contemplated in Clause 17.3, the IPC shall have the right to drill such Wells pursuant to Subclause 36.14(c).

36.19 ADDITIONAL VOLUMES OF GAS - Where the Gas supply to the Tuktoyaktuk area can be expanded because of increased demand for Gas, the IPC shall have the right to obtain such additional Gas in the following manner and in the following sequence:

(a) The IPC and the Lessee shall evaluate whether such increased volumes can be supplied from the reserves in the Gas Project Spacing Units, or any Gas that may have drained into the Gas Project Spacing Units, and where sufficient reserves are available the volumes in the Gas Purchase Contract shall be increased accordingly; or

(b) where such Gas reserves are not sufficient, the IPC shall make an offer to purchase additional volumes of Gas from the Lessee pursuant to Clause 36.1 herein provided such Gas can be delivered economically; or

(c) where the Lessee does not have producing Gas Wells from which such volumes can be obtained economically or does not intend to drill new Wells for the supply of such volumes, the IPC may propose to drill one or more Wells in the Lease Area pursuant to Clause 17.3 hereof. In the absence of the Development operating agreement contemplated in Clause 17.3, the IPC shall have the right to drill such Wells pursuant to Subclause 36.14(c) hereof.

36.20 **IPC'S OPTION TO OPERATE** - The IPC shall have the option, with one year's notice, to operate the entire Gas Project, including operating the Gas Wells as contract operator for the Lessee. The IPC shall in this event bill the Lessee for its share of the costs pursuant to Clause 36.11. The Lessee agrees, if requested by the IPC, to negotiate a contract for the training of personnel and transfer of know how and technology required for the safe and prudent operation of the Wells and field facilities. If the terms cannot be agreed to, the matter will be submitted to arbi trat ion.

36.21 **RESERVATION FOR FUTURE USE** - To the extent necessary, the Lessee shall reserve the Gas in the reservoirs from which Gas is produced for the Gas Project outside the Gas Project Spacing Units for future use by the Gas Project. Any Gas drained into any Gas Project Spacing Units, prior to the Commercial Production of the Gas from the same reservoirs for other purposes shall be deemed to be owned by the Working Interest parties in the Gas Project Spacing Units in proportion to their Working Interest.

SCHEDULE "C"

ATTACHED TO AND FORMING PART OF
AN OIL AND GAS CONCESSION WITH RESPECT TO
THE TUKTOYAKTUK 7(l)(a) LANDS
AND WITH A TERM DATE OF OCTOBER 1ST, 1986

GAS PURCHASE CONTRACT

BETWEEN

THE LESSEE AS DEFINED IN THE

LEASE

AND

THE INUVIALUIT PETROLEUM CORPORATION

TUKTOYAKTUK AREA

INDEX

GAS PURCHASE CONTRACT

THIS CONTRACT made as of the day of ______________, A.D. _____ (hereinafter called the "Effective Date")

BETWEEN:

THE LESSEE as defined in the LEASE
(hereinafter called "Seller")

- and -

THE INUVIALUIT PETROLEUM CORPORATION,
having an office at the City of Calgary, in
the Province of Alberta
(hereinafter called "Buyer")

WITNESSES THAT:

WHEREAS it is agreed between the Buyer and the Seller that the words and definitions in this Gas Purchase Contract (the "Contract") unless otherwise defined herein shall have the same meaning as the words and definitions in the Lease, to which the form of this Contract is a Schedule;

AND WHEREAS Seller is entitled to produce Gas from certain reserves from one or more Wells in the Lease Area and has available for sale from the Wells certain volumes of Gas;

AND WHEREAS Buyer requires Gas for processing to obtain Marketable Gas for distribution in the settlement of Tuktoyaktuk and wishes to purchase Gas from the Seller;

AND WHEREAS Seller has agreed to sell Gas to Buyer from the Wells, in accordance with the terms and conditions hereinafter contained.

IN CONSIDERATION of the mutual covenants herein contained, it is agreed as follows:

1. DEFINITIONS

1.1 The following words and terms wherever and whenever used or appearing in this Contract shall have the following meanings:

(a) "Annual Volume" means a volume of Gas equal to the number of Days in a Contract Year times the Daily Contract Quantity;

(b) "Contract Start Date' means the date of first delivery of Gas from the Seller to the Buyer;

(c) "Contract Year' means a period of twelve (12) consecutive Months beginning on January 1, provided however that the first Contract Year shall begin on the Effective Date and end on the December 31 next following;

(d) 'Daily Contract Quantity" means twenty (20) 10^3m^3 per Day during the term of this Contract;

(e) "Day" means a period of twenty-four (24) consecutive hours, beginning and ending at 7:00 o'clock a.m. Mountain Standard Time;

(f) "Deficiency Volume" means the volume of Gas required to be taken in a Contract Year but not taken by Buyer pursuant to the provisions of this Contract;

(9) "Hypothetical Pipeline Length' means the total length in meters rounded to the nearest 100 meters of a line consisting of two segments; the first segment being a straight line connecting the locations of the **two** Gas Wells for the Gas Project ana the second segment being a straight line connecting a point at 133°00' West Longtitude/69° 25' North Latitude (herein after the 'Reference Point") with the location of the Gas Well closest to the Reference Point. The lengths of the two segments shall be obtained by scaling using a 1:50 **000** scale map showing the locations of the two Gas Wells and the Reference Point;

h) "Maximum Daily Volume" ~.cans a volume of Gas equal to forty (40) 10^3m^3 per Day when the Seller has one (1) Well operational and eighty (80) 10^3m^3 per Day when the Seller has two (2) Wells operational;

(i) "Month" means a period beginning at 7:00 o'clock A.M. Mountain Standard Time on the first Day of a calendar month and ending at 7:00 o'clock A.M. Mountain Standard Time on the first Day of the next succeeding calendar month;

(j) "Party" or "Parties" means, as the context requires, Seller and/or Buyer;

(k) 'Seller's Reserves" means a portion of the Gas reserves contained in that part of the Lease Area within which the Seller is able to produce Gas from Acceptable Gas Reservoirs. That part of the Lease Area containing Seller's Reserves will be outlined on a map and attached hereto as Exhibit A upon the Effective Date;

(1) 'Standby Fuel" means Gas, Marketable Gas or propane as selected by the Seller and delivered to the Buyer in lieu of Gas from the Acceptable Gas Reservoirs. Gas delivered as Standby Fuel will be of a quality such that the Buyer can produce a Marketable Gas;

(m) The term "10^3m^3" shall mean one thousand (1,000) cubic metres of Gas determined on the measurement basis set forth in this Contract;

(n) "Winter Season" means that period of time being five (5) consecutive months beginning on the first Day of December and ending on the last Day of April.

II. COMMITMENTS OF THE PARTIES PRIOR TO GAS DELIVERY

2.1 Within the first Winter Season following the Effective Date, provided the Effective Date has occurred prior to July 1 of a calendar year, the Seller shall complete two (2) Gas Wells maintained or drilled pursuant to Article XXXVI of the Lease. Where the Effective Date occurs on or after July 1 of a calendar year, the Seller shall complete the two (2) Gas Wells no later than the end of the second Winter Season following the Effective Date.

2.2 During the first and second Contract Years, the Buyer shall construct and install the required Gas gathering and processing facilities, Gas transmission lines and distribution system for the taking of Gas hereunder.

2.3 The Contract Start Date shall occur at the beginning of the third Contract Year or earlier where the Buyer and Seller have installed their respective facilities and all preparations for the delivery "and taking of Gas have been completed to each Party's satisfaction and notice thereof has been delivered to the other Party,

III. QUANTITY OF GAS

3.1 (a) Subject to the other provisions of this Contract, during each Contract Year from the beginning of the third Contract year, Buyer shall request, take and Pay for, or nevertheless pay for, if available and not taken, the Annual Volume; provided however that where the Contract Start Date occurs before the beginning of the third Contract Year the Buyer may request during the period prior to the third Contract Year volumes less than the Annual Volume but at rates up to the Maximum Daily Volume.

(b) When calculating whether Buyer has complied with the Annual Volume obligation under this Contract, Buyer will use the greater of the volume of Gas requested by Buyer or the volume of Gas delivered by Seller to Buyer. Such calculations shall be made on an annual basis.

3.2 Seller dedicates to the performance of this Contract the Seller's Reserves contained in the Acceptable Gas Reservoirs within the Spacing Units of the Wells completed to supply the Gas required for this Contract and covenants not to enter into any other contract for the sale of such Gas the effect of which will prevent or jeopardize Seller's ability to perform Seller's commitment to deliver the Maximum Day Volume hereunder. However, it is understood between the Parties that where the Gas reserves in the Spacing Units become insufficient during the term of this Contract to meet the Seller's obligations, the Seller shall be responsible to make such alternate arrangements as may be necessary in order to meet its Contract obligations.

3.3 During the term of this Contract, Buyer shall have the right during any Contract Year, after complying with Buyer's obligation with regard to the Annual Volume to recover any Deficiency Volume provided that Seller shall not be obligated to deliver Gas in excess of the Maximum Day Volume then in effect.

3.4 Seller is responsible for the supply of Gas to the Delivery Point (as defined in clause 6.1) as requested by the Buyer up to the Maximum Daily Volume. The Buyer shall have in place measures to cope with Gas interruptions due to failures of its facilities for a period of 7 consecutive days of the peak demand of its non-interruptible customers. Where the Seller fails to supply Gas, except where the Seller's inability to supply is as a direct or indirect result of the Buyer's operations or facilities, the Seller shall be responsible for the supply of Standby Fuel to permit the Buyer to meet its obligations to non-interruptible customers. For the purposes of this clause the Buyer agrees that its non-interruptible customers shall be defined as only those customers in the community of Tuktoyaktuk using Gas for residential and commercial heating; provided, however, that non-interruptible customers shall, regardless of use, not include Northern Canada Power Commission, Northern Transportation Company Ltd., Arctic Transportation Ltd., or any of their affiliates, successors, or assigns. Furthermore, commercial heating shall not include the use of Gas to heat industry work camps, the use of Gas for Petroleum Operations, or the use of Gas for industrial purposes.

If the Standby Fuel is acquired from the Buyer by the Seller, then the Seller shall at its option:

(a) Replace the Standby Fuel acquired by Seller from Buyer within a reasonable time, or

(b) recompense Buyer for the price of the Standby Fuel at the Buyer's acquisition cost of the Standby Fuel.

3.5 The Buyer shall have the right, from the Contract Start Date, to purchase from the Seller and the Seller shall deliver to the Buyer each day the volume of Gas required by the Buyer up to the Maximum Daily Volume during any Day and the Annual Volume in any Contract Year and the Seller shall deliver greater volumes if requested by the Buyer and if the Seller's Acceptable Gas Reservoirs and Wells are capable of delivering such additional volumes. Whether the Seller's Acceptable Gas Reservoirs and 'liens are capable of delivering such additional volumes shall be determined in accordance with clause 36.19 of the Lease.

During the initial term of this Contract the Parties may agree to increase the Maximum Day Volume and the Daily Contract Quantity where the circumstances justify such increases.

IV. QUALITY OF GAS

4.1 Gas sold and delivered hereunder shall be in the condition in which it is produced from the Wells regardless of pressure, heating value, constituent parts or impurities, and formation water content except to the extent that the Seller's existing Well equipment is capable of controlling said condition.

V. MEASUREMENT OF GAS

5.1 All Gas delivered hereunder shall be measured by a suitable meter of standard make to be furnished, installed and kept in repair by Buyer. The amount of Gas so metered shall be determined in units of 1,000 cubic meters 10^3m^3 at an absolute pressure of one hundred one and three hundred twenty-five one thousandths (101.325) kilopascals and at a temperature of fifteen (15°) degrees Celsius (exact to only one decimal place). The meter shall be open to inspection at all reasonable times by a representative of Seller in the presence of a representative of Buyer. If any question arises as to the accuracy of measurement the meter shall be tested upon the demand of either Party. The expense of any such test shell be borne by the Party demanding it if the meter is found to be correct and by Buyer if found to be incorrect. A registration within 2% of correct shall be construed correct. Settlement for any period of inoperation of inaccurate measurement shall be made in accordance with the average readings taken during the last preceding sixteen (16) Days when the meter was registering accurately.

5.2 The standards of measurement and tests for the Gas delivered hereunder shall be governed by the regulations promulgated by the government agencies having jurisdiction and where permitted thereunder, or where there are none in place, by the practice recommended by the American Gas Association which the Buyer demonstrates to the Seller to be the most appropriate for this Contract. If the Parties cannot agree on the practices to be adopted, the matter shall be submitted to arbitration for determination.

5.3 The Seller reserves the right at its expense to install its own metering facilities.

5.4 The Daily Contract Quantity, the Maximum Daily Volume and the Price defined herein are based on a Gas with an expected gross heating value of thirty six (36) megajoules per cubic meter. Where it is determined that the Gas delivered by Seller from the Acceptable Gas Reservoirs has an actual gross heating value different than thirty six (36) megajoules per cubic meter, the Daily Contract Quantity and Maximum Daily Volume shall be adjusted in direct proportion to thirty six (36) megajoules per cubic meter divided by the actual gross heating value and the Price shall be adjusted in direct proportion to the the actual heating value divided by thirty six (36) megajoules per cubic meter.

VI. <u>POINT OF DELIVERY</u>

6.1 For the purpose of this Contract the delivery point where the Seller shall deliver Gas (the "Delivery Point") shall be 'the point where the Gas first enters the Production Facilities of the Buyer.The Delivery Point. will be immediately downstream of the Seller's wellhead. .

6.2 The delivery pressure of the Gas to be delivered under this Contract shall be that pressure available at the wellhead less line losses from the wellhead to the Delivery Point; provided however that such pressure shall not exceed levels which the Production Facilities of the Buyer can safely accommodate.

6.3 Possession of and title to all Gas delivered hereunder shall pass from Seller to Buyer at the Delivery Point and until such delivery, Seller shall be deemed to be in control or possession of, have title to, and be responsible for such Gas, and after such delivery Buyer shall be deemed to be in control or possession of, have title to, and be responsible for such Gas.

VII. <u>TERM</u>

7.1 This Contract shall be effective for an initial term (the "Initial Term") being the lesser of twelve (12) Contract Years from the Effective Date or the end of the Month during which the cumulative deliveries of Gas by the Seller to the Buyer have amounted to 80 000 000 cubic meters.

7.2 This Contract may be renewed under 'such terms and conditions as are stipulated in the Lease.

VIII. PRICE

8.1 Subject to clause 5.4 of this Contract, for the period commencing on the Contract Start Date of this Contract and for the balance of the Initial Term thereafter, the price to be paid by Buyer to Seller for all Gas purchased hereunder shall be:

(a) thirty-five dollars and forty-five cents ($35.45) per $10^3 m^3$ where the Hypothetical Pipeline Length is greater than ten thousand (10 000) meters; or

(b) forty-five dollars ($45.00) Per $10^3 m^3$ where the Hypothetical Pipeline Length equals ten thousand (10 000) meters; or

(c) that price in dollars per $10^3 m^3$ as determined by the formula below where the Hypothetical Pipeline Length is less than ten thousand (10 000) meters

$$\text{Price} = 45.00 + (10000 - \text{Hypothetical Pipeline Length}) \times 0.0025$$

8.2 For any Deficiency Volume recovered, an adjustment shall be paid to the Seller by the Buyer for the difference between the price which was paid for such Deficiency Volume hereunder and the price required to be paid at the time the Gas is taken by Buyer. A Deficiency Volume when taken shall be deemed to be taken on a first in, first out basis (FIFO).

8.3 If any governmental authority changes the basis or method of measurement of Gas delivered hereunder, notwithstanding anything herein contained to the contrary, the price per $10^3 m^3$ for Gas purchased hereunder shall be adjusted to compensate for the change in the basis or method of measurement, to the end that the total amount of money payable for volumes of Gas purchased according to the measurement provisions set forth herein shall remain unaffected by such change.

8.4 Where the Effective Date of this Contract is delayed beyond July 1, 1988, the price established in Clause 8.1 shall be increased by one half of one percent (0.5%) for each Month that the Effective Date is delayed beyond July 1, 1988.

IX. BILLINGSAND PAYMENTS

9.1 Seller shall render to Buyer on or before the fifteenth (15th) Day of each Month a statement setting forth the quantity of Gas delivered by Seller during the preceding Month and the total amount payable therefor. Buyer agrees to pay Seller on or before the twenty-fifth (25th) Day of each Month the total amount payable for the quantity of Gas delivered by Seller to the Buyer during the preceding Month. Each such payment shall be made in Canadian funds by cheque drawn in Seller's favour and mailed or tendered to Seller at 237 - 4th Avenue, S.W., Calgary, Alberta, T2P 0H6, or at such other place in Canada as Seller may designate by written notice served by Seller on Buyer. If Buyer fails to make any such payment, or any portion thereof, to Seller when same is due, interest thereon may at Seller's option accrue at the rate of interest per annum which is two percent (2%) more than the Prime Rate and if such failure to pay continues for Sixty (60) days, Seller, in addition to all other remedies, thereafter may suspend deliveries of Gas hereunder and if such default continues for thirty (30) additional days, Seller thereafter may, in addition to any other rights Seller may have, terminate this Contract; provided, however, in order for Seller to have the right to suspend deliveries or terminate this Contract, Seller must first have notified Buyer in writing fifteen (15) days prior to exercising either or both of such rights of its intent to do so and give Buyer the right to pay the amount so due to Seller within such fifteen (15) day period. Each party shall have the right to inspect and examine at all reasonable times the records of the other party pertaining to the purchase and sale of Gas hereunder. Records shall be kept a minimum of three (3) calendar years after any one Contract Year.

X. LAWS AND REGULATORY BODIES

10.1 This Contract shall be governed in accordance with, and the right and obligations of the Parties hereunder are subject to all applicable present and future laws, rules, regulations and order of any legislative body or duly constituted authority of the Northwest Territories "(NWT)".

X1. FORCE MAJEURE

11.1 The provisions related to Force Majeure in the Lease shall apply to this Contract. In the event of the occurence of a Force Majeure event, the Annual Volume shall be reduced by an amount equal to the Daily Contract Quantity times the number of Days during which the Force Majeure event existed. The Seller's obligation to provide Standby Fuel shall not be abrogated by Force Majeure unless the Force Majeure affects the acquisition or the delivery of Standby Fuel.

XII. INDEMNIFICATION

12.1 Buyer agrees to indemnify, protect and save harmless Seller from and against any and all claims, demands and liabilities of whatsoever kind and nature which may arise out of or result from or be directly or indirectly attributable to the entering into or performance or non-performance of this Contract by Buyer, or the use of the Gas acquired by the Buyer hereunder, except where such damage, injury, claims, demands and liabilities arise through the negligence of the Seller, its servants or agents.

12.2 Seller agrees to indemnify Buyer and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of adverse claims of any and all persons to said Gas (except with respect to the use thereof) or to taxes, licence fees or charges thereon which are applicable before the title passes to Buyer or which may be levied and assessed upon the sale thereof to Buyer.

XIII. MISCELLANEOUS PROVISIONS

13.1 No waiver by Buyer or Seller of any default by the other under this Contract shall be effective unless given in writing and no waiver whether or not given in writing shall operate as a waiver of a future default whether of a like or different 'character.

13.2 This Contract shall bind and enure to the respective successors and assigns of the Parties hereto provided that neither Party shall assign this Contract, other than to Affiliates, without the consent of the other, which consent shall not reasonably be withheld. No assignment shall release either Party from such Party's obligations hereunder without the written consent of the other Party to such release. Nothing herein contained shall prevent either Party from pledging or mortgaging its rights hereunder as security for its indebtedness provided that the security holder agrees to be bound by this Contract if it exercises its security.

13.3 The headings used throughout this Contract are inserted for reference purposes only, and are not to be considered or taken into account in construing the terms or provisions of any Article nor to be deemed in "any way to qualify, modify or explain the effect of any such provisions or terms.

13.4 Every notice, statement or bill provided for in this Contract shall be in writing directed to the party to whom given, made or delivered at such Party's address as follows:

SELLER:

B[illegible]: The Inuvialuit Petroleum Corporation
Bow Valley Square #3
2080, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

Any notice mailed by registered mail shall be deemed to have been given to and received by the addressee forty-eight (48) hours, excluding Saturdays, Sundays, and statutory holidays, after the mailing thereof, and in the event that the same is delivered, as soon as such delivery has been made to the Party's address as hereinbefore set out. Either Party may change its address by giving written notice to the other Party.

13.5 No amendment nor variation of this Contract shall be effective or binding upon the Parties hereto unless it is set forth in writing and has been duly executed by each of the Parties hereto by its respective proper officers or authorized representative in that behalf.

13.6 This Contract shall supersede any other agreements or instruments oral or in writing between the Parties hereto relating to the sale and purchase of Gas from Seller's Reserves.

XIV. <u>ARBITRATION</u>

14.1 The provisions regarding arbitration in the Lease shall apply to this Contract.

XV. SELLER'S RESERVATIONS

15.1 Seller hereby expressly reserves unto itself, the right to operate Seller's Reserves free from any control by Buyer in such a manner as Seller in its sole discretion may deem advisable, and without limiting the generality of the foregoing, to determine the manner in which the quantities of Gas to be delivered hereunder shall be produced by Seller and to use Gas produced from the Acceptable Gas Reservoirs in Petroleum Operations in the Lease Area.

15.2 Seller may extract hydrocarbon constituents, other than methane, from the Gas prior to delivery hereunder, and shall have the right to remove such methane as is necessary to be removed from the Gas in recovering other constituents; provided that Seller in such processing shall not reduce the gross heating value thereof below thirty-six (36.00) megajoules per cubic meter.

15.3 Seller shall not be required by the provisions of this Contract to produce Wells in excess of their respective allowable rates of flow as fixed by law or regulatory bodies, or in excess of their maximum efficient rates of flow as determined by Seller.

IN WITNESS WHEREOF this Contract has been properly executed by the Parties hereto as of the date first above written.

SELLER

____

____

BUYER

____

____

FEASIBILITY STAGE PLAN

TUKTOYAKTUK GAS PROJECT

INUVIALUIT PETROLEUM CORPORATION

TABLE OF CONTENTS

1. INTRODUCTION

1.01 Preamble

In exploring the Tuktoyaktuk field, Esso et al have found significant gas/ condensate and crude oil reservoirs at depth, but shallow gas has also been noted of a quality suitable for general use at the most recent ('84/'85) wells. Preliminary studies to date indicate the likelihood of an economically viable local gas production/sales system for the Tuktoyaktuk region.

Currently a scoping study - cost shared by Inuvialuit Petroleum Corporation and Esso - is underway to narrow alternates in certain areas and to define the technical bases for the system. Prior studies by IPC have examined markets in some detail, as well as most system parameters. These studies have indicated that the use of natural gas can probably economically displace virtually all distillate fuels used for heating and electricity generation in the Tuk area. Current drilling will provide sound data on gas availability.

The deeper gas/condensate reserves appear to require large gas and condensate markets for their successful exploitation. Such markets and related pipeline systems to economically move the products, appear some years off. Hence, the shallow gas represents the logical supply source to the Tuk area.

The IPC has already initiated discussions with regulatory and other agencies relative to being granted a gas franchise for the Tuk area and in owning and operating the system, following purchase of the gas at the wellhead from Esso.

The Feasibility Stage defined here carries on from the prior and current work, and will start about the time that the current drilling program will have provided the necessary data on shallow gas reserves and their producibility.

Absolute reliability will be essential in a Tuk gas supply system. While the component elements are generally standard, they are numerous. The project is unique in the N.W.T. and the locale is a difficult one weather and soil-wise. Hence, very careful planning is an absolute essential - the Feasibility Stage is the most important part of that planning in order that a viable, economically-attractive gas system evolves.

1.02 Objectives

The Feasibility Stage will have two principal objectives:

I Provide economic and technical data for decision making - to proceed, to wait, or to cancel, and

II Move the project along at a rate that will allow gas to be delivered to virtually all areas of Tuk by September, 1987, recognizing barge transport windows in the summer/early fall of 1986.

The overall cost estimates from the Feasibility Study should be acurate to ±25% with much of the potential error due to weather and/or transport related events not foreseen at the time of estimating. More accurate costs will be available after major materials and equipment is ordered in early/mid summer 1986 and the various construction packages are tendered - say by October 1986. By that time all but "acts of God" contingencies should be removable. The Feasibility Study estimates should be suitable for IPC "go''/"no go" decision making.

1.03 Work Sectors

The Feasibility Study is concerned with defining all work needed to accomplish an economically sound, highly reliable, and progressive gas distribution system for the Tuk area.

For convenience, the activities of this stage of development are discussed later under the following headings:

Planning	This sector covers development of formal plans for th s and subsequent stages of activities.
Corporate	Here IPC gas system organization will be defined, peep' e needs specified, insurance

	plans developed and financing studied and approach defined.
Marketing	Consumer needs will be analyzed to define appliance and metering needs, and rate structures will be developed.
Operations	Operational organization and policies will be outlined.
Project	Scopes of work will be finalized for all facilities, long delivery equipment and materials specified and brought to point where orders can be placed.
Feasibility Stage	Aside from management of the studies, this sector will tie all estimates together and provide IPC management the data required for a "go"/"no go" decision.

As the project develops other breakdowns may become more realistic. Also the scoping study may redefine certain aspects which will again change the above list.

Also it must be noted that each activity of the project integrates into many other activities. Such relationships must be recognized in all work - no one sector can be optimized in its own right, only the whole can be fully optimized.

1.04 Prior Work

The IPC staff and its consultant, Mr. P. Van Meurs, have been working on this project, as well as on negotiations with Esso, for over a year. The negotiations with Esso have arrived at formal agreements, covering most aspects. However, there remain a number of technical and operational interfaces and arrangements still to be ironed out.

Through Mr. Van Meurs, market analyses have been carried out and preliminary facility concepts developed and costed. The current scoping study will tie these pieces together, decide between alternates on the field end, define system design bases, and provide data on a possible cross-harbour line to Esso. RTM Engineering Ltd., Canuck GEI Engineering, and Ms. S. Bogach are combining on the Scoping Study, continuing on from their previous work on system definition/economics, pipeline concepts/costs and market data, respectively. The Scoping Study parallels the drilling program and will be varied to suit drilling results if appropriate. However, it will be completed in draft form towards the end of January, well before the end of this year's drilling program.

IPC staff and Mr. Van Meurs have had extensive discussions with Tuk area officials and various N.W.T. agencies relative to this project. A gas franchise application will be presented in the next month or two to the N.W.T. Public Utility Board as a followup to certain of these discussions.

1.05 Continuity

This Feasibility Stage is the last major step before equipment is ordered and the gas system project formerly commenced, except for any hearings that may be required. At this time the approval processes have not been well defined, but will be by the time the Feasibility Study is started.

The planning and activities of the Feasibility Stage must recognize its fit with prior, parallel and future activities. It is only part of the overall effort needed to get the system into operation.

2. TUK GAS SYSTEM OVERVIEW

2.01 General

This section briefly outlines the current concepts for the system. Certain aspects are now being clarified in the Scoping Study and ongoing drilling may revise other aspects. Hence, please consider this a preliminary review.

Roughly 1 million standard cubic feet (28,300 m^3) per day of natural gas will be produced, processed, pipelined and distributed to industrial, commercial, institutional , and residential users in Tuk. The natural gas identified to date in shallow formations is free of noxious compounds and virtually all hydrocarbon heavier than water.

2.02 Field

One (or two) well(s) owned and operated by Esso will provide gas to dehydration facilities owned and operated by IPC. The number of wells and nature of dehydration facilities are being studied in the scoping study in order to provide a highly reliable supply system.

The wells are roughly 8 to 10 kilometers south of Tuk, 1 to 3 kilometers east of the Inuvik-Tuk power line. The specific wells to be used will not be identified for another month or two due to drilling in progress. Due to permafrost, Esso will be providing heating to the wells to prevent freezeup at the well. The dehydration facilities will remove traces of water to prevent freezeup in the rest of the system.

2.03 Pipeline

From the field a single line will bring gas at high pressure (close to that of the producing formation) to a terminal roughly south of NTCL. The pipeline will be designed for permafrost conditions and will be oversized to provide short term surge (for minor field repairs and fluctuations in demand), as well as expansion capacity.

2.04 Terminal

At the terminal the pressure will be reduced first for distribution to the major industrial companies and then for distribution to the townsite at the lowest pressure. Odorant will be added to all sales gas to indicate its presence in case of leaks.

At the terminal a backup system will be provided to supply a propane/air mixture to the townsite system in the event of a long-term disruption to the supply from the field. (Industrial users will be cut off at such a time.)

The terminal site will also act as a communications, warehouse, shop, office center for the entire system.

2.05 Distribution

The oil companies, NCPC, NTCL and other large users will receive their gas at a higher pressure than allowable in the townsite, to minimize pipeline costs and to best accommodate large users. A loop or single line is envisaged, with a possible cross-harbour line to Esso. (The latter is under study.)

The townsite will be served by a series of looped, low-pressure distribution systenms, the loops allowing small portions to be taken out of service without affecting the whole line.

2.06 Appliances

Many existing heaters will require replacement, and other equipment now using oil will require modification in order to use gas. Hence, a significant portion of the project will be the supply and installation of new appliances and the modification of others.

2.07 Operations

A new organization will be set up by IPC to operate the dehydration, pipeline, terminal and distribution facilities as well as to install and repair appliances. (Portions of these services may be subcontracted or handled by others.)

The new organization will promote the use of gas and train users as to its safety and the use of gas fueled appliances.

2.08 Note

The facilities to be built and operated by IPC are in no case unique [although Esso may have some unique problems in preventing freezing in the producing well(s)]. Also the overall gas system is relatively small compared with many northern Canadian gas systems. However, the situation is complicated here by the need to consider all aspects of field operations (including production), pipelining and distribution at one time and in the context of a new organization to be developed at the same time the system is installed. At the same time few of the potential users have little or no experience in the use of gas - it will be a new form of fuel to them. Thus the planning and promotion aspects loom very large in the Feasibility Stage.

3. SCHEDULE

At this time the regulatory regime that will apply has not been defined in sufficient detail to assess its impacts on schedule. However, in order to otherwise fit the planned startup date it is essential that the go/no go decision be made prior to May 15, 1986. Assuming a March 1 start for this stage and a 2 week period in which IPC makes its decision requires a Feasibility Stage completion by the end of April, 1986.

The timing is primarily set by the need to move the large pipe - 10 kilometers or so - north by barge before freezeup this year. Also field and terminal modules and distribution piping will most economically be, moved by barge and are needed before breakup in 1987.

It is now hoped that the regulatory requirements - permits and hearings - for this comparatively small system can be fitted in to allow meeting the overall schedule. It appears unlikely that a go/no go decision can be taken without the principal approvals being in place. Thus their timing is very critical.

It is assumed herein that Esso's program to develop the well production facilities will be completed by the summer of 1987.

The rest of this memorandum assumes that the work of the Feasibility Stage will be completed by April 30, 1986, with a start on March 1 or, preferably, earlier.

Customer changeover is very important and may constrict the acceptance and/or rate of acceptance of gas by various potential users. This must be defined at least in preliminary terms in this Feasibility Stage.

4. FEASIBILITY STAGE PROGRAM

4.01 Preamble

Here we review the major activities of the Feasibility Stage and their planned output. The inter-relationship between activities is not stressed in the interests of brevity, but will be emphasized throughout the program. We would refer the reader again to the objectives of this stage - data for go/no go decision, continuity to permit summer/fall 1987 start of gas distribution in Tuk.

A preliminary (large) critical path diagram has been prepared to show the inter-relationships between activities. However, due to its complexity and the likelihood of change, is not presented here. Also the short time available for the Feasibility Stage requires that many activities proceed in parallel with a high degree of interfacing with other activities. The diagram has been used primarily to check on the practicality of meeting the schedule.

The Scoping Study is now in progress and forms the major technical forerunner to the Feasibility Stage, in parallel with ongoing permit/ hearing discussions and IPC internal development.

4.02 Planning

The Feasibility Stage must integrate with:

- Esso's wellhead facilities planning,
- Franchise and other regulatory negotiations,
- Internal IPC development,
- Related IDC developments,

  Final gas reserve delineation,

  Oil and/or deep gas/condensate development decision,

- Tuk townsite and commercial/institutional /industrial planning - e.g. possible expansion of Gulf facilities for expanded offshore program, and

- Other activities and development planning impacting on markets and/or facility needs.

In effect even though the time is short, numerous interfaces must be considered.

The Scoping Study will be defining facilities in a general manner and decisions arising from it will eliminate most curent major system options. The Scoping Study should also give a good picture of the regulatory regime not available at this time.

During the Feasibility Stage, the following plans will be developed:

a) Feasibility Stage Plan

Detailed network development at onset of work outlining all activities, defining their inter-relationships and durations. In effect this will update this document and provide the interfacing constraints.

This plan will include a revised budget and organizational structure, including all interface relationships.

b) Corporate Plan

This plan will cover all activities subsequent to a “go” decision as they relate to organizational structure, personnel needs/ specifications/training, ongoing operations advisers (if any), facilities/equipment, insurance programs’, policy development, banking, legal, audit, financing, etc.

c) Marketing Plan

This plan will lay out all aspects of pre gas, startup and full operation customer relations and appliance sales, subsequent to the “go” decision.

d) Operations Plan

This plan will define all after the “go” operational activities - pre gas, startup and full operations. Staffing and subcontracting planning, spare parts, vehicles, shop, warehouse, meter reading and meter replacement will be a few of the many factors to be developed in these ongoing activities.

Facilities Plans - for each of:

e) Field

f) Pipeline (including Esso crossing if applicable).

g) Terminal and Related

h) Distribution

The following will be developed for all work subsequent to the “go” decision:

- Scope of facilities
- Design of programs and bases
- Activity diagrams and descriptions and schedules
- Construction plan bases
- Budgets

i) Support and management services:

- Engineering
- Project Management
- Inspection
- Surveying

- Geotechnical
- Environmental
- Transport Planning
- Temporary facilities
- Warehousing, roads, etc.
- Permits

The following will be developed for each of these items:

- Scopes
- Bases
- Budgets
- Activity descriptions and diagrams

j) All the facilities plans will be inter-related through master plans.

4.03 **Corporate**

During the Feasibility Stage the following activities will be carried out :

a) Define IPC relevant policies and guidelines.

b) Define structure for gas system development.

c) Define structure for gas system operation.

d) Define sub-contracting policies.

e) Define insurance policies and develop costs. (This item may be quite difficult and will need appreciable emphasis.)

f) Define overhead charge policies and develop costs.

g) Define personnel needs and specify each, as well as burden related policies.

h) Define personnel training needs/preliminary program outlines.

i) Define how organization will take shape - e.g. Is outside small gas utility expertise required for several years? When should staff be hired? etc.

j) Develop financing plan
- Start from preliminary estimates available,
- Determine options,
- Analyze,
- Discuss with financing organizations as appropriate,
- Compare with final cost estimates,
- Recommend plan..

k) With marketing develop rate structure proposals (acceptable to N.W.T. PUB) considering short and long term fiscal objectives, market potentials and risk.

1) Recommend action to IPC board as to “go''/”no go”.

m) Provide rapport with local community, territorial and federal governments as appropriate.

n) Develop ongoing plan [See 4.02(b)].

4.04 Marketing

During the Feasibility Stage the following activities will be carried out:

a) Update all market forecasts (and keep current).

b) Advise market data for facilities planning.

c) Develop short term potential customer relations program and put into action.

d) Survey potential users as to appliances, meter locations, concerns as to gas use, etc. (AFTER “C” !)

e) Decide appliance types to be used and survey potential sources.

f) Specify and inquiry appliances to develop costs.

g) Develop installation program outline and cost out.

h) Develop transport and warehousing plans.

i) Outline ongoing appliance marketing program (all IPC, mixed or all by others).

j) Outline ongoing market development/customer relations program.

k) Work with facilities personnel to select meter types, enclosures (as needed).

1) Assist in franchise negotiations.

m) Assist in local government negotiations re ROW's, etc.

n) Develop interruptible contract terms acceptable to customers.

o) Develop rate structure proposals and standard contract terms [See also 403(k)].

p) Review rate structures relative to displaced fuel costs to ensure competitiveness.

4.05 Operations

During the Feasibility Stage the following activities will be carried out:

a) Define organizational needs.

b) Define spare parts policies and costs.

c) Define appliance servicing policies and costs (if any).

d) Define meter reading program and billing procedures.

e) Define other in-house/sub-contract activities.

f) Define personnel needs - specify and defining training needs and costs.

g) Define service facility needs - space and equipment - and costs.

h) Define gas supply (from Esso) arrangements and outline procedures.

Note that "operations" as used here encompasses field, pipeline, terminal and distribution.

4.06 **Project**

During the Feasibility Stage the following activities will be carried out:

A) Field and Terminal Areas (each of):

a) Update scope of facilities.

b) Define prefabricated packages - process and mechanical specifications, and send out (a) for quotations.

c) Select locations and develop preliminary locations.

d) Complete process and instrument diagrams for all process-related facilities.

e) Specify and inquiry long delivery items not incorporated into packages.

f) Specify buildings and cost.

g) Specify overall communications systems and cost.

h) Interface with Esso on field end relative to all of above.

i) Develop preliminary access and foundation designs and estimate fill and costs.

j) (With pipeline activities) inquire and cost fill.

k) Develop preliminary construction plan.

1) Develop capital cost estimate and construction schedule.

B) Pipelines (Including Esso crossing)

a) Update scopes.

b) Select preliminary route.

c) Specify pipe and coating.

d) Inquiry pipe and coating.

e) Define approximate fill needs [See Item A(i) above].

f) Define barging and other handling costs and schedules.

g) Prepare preliminary construction plan.

h) Develop capital cost estimates.

i) Define detailed routing methodology and test needs.

C) Distribution

a) Develop master legal survey data.

b) Locate each potential consumer and his load on small-scale map.

c) Develop and analyze alternates for east side medium pressure distribution system.

d) Develop and analyze alternates for NCPC, NTCL, etc. (near terminal).

e) Develop and analyze alternates for townsite.

f) Finalize distribution pipeline plan concepts, sizes, etc.

g) Develop typical user service branches (where not done in scoping study).

h) Develop (with marketing) meter types and enclosure standards.

i) Develop preliminary construction plan.

j) Inquiry meter assemblies, housing, and other special items.

k) Summarize pipe needs specifying and inquiry.

1) Define detailed routing methodology.

m) Develop capital cost estimates.

D) <u>General</u>

a) Define all permits and license needs.

b) Develop permit applications (where needed prior to detailed design).

c) Develop environmental impact analysis as required for above.

d) Provide geotechnical consulting support to all activities noted above.

e) Outline master transport plan for construction materials, prefabricated modules and buildings, appliances, etc.

f) Compile overall scope of facilities.

g) Compile overall capital cost estimate.

h) Develop Facilities Plan as in 4.02(e) through (j).

4.07 Feasibility Stage

In order to operate these studies the following are required:

a) Study management/co-ordination.

b) Study cost management.

c) Study time management.

d) Cost compilations and financial analyses (ROI, etc.)

e) Reporting to IPC.

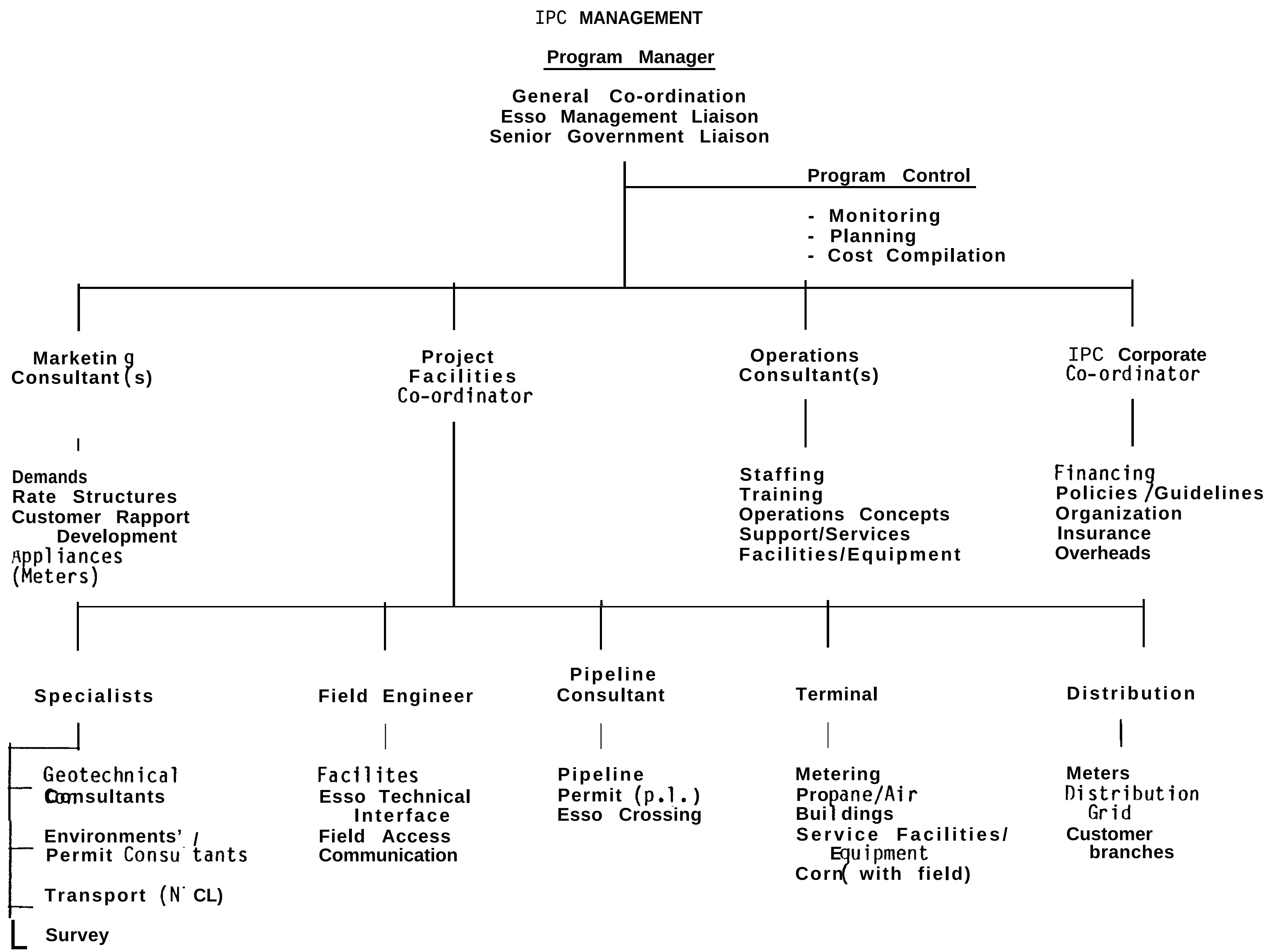
f) External liaison (not referred to elsewhere).

g) Permit expediting/hearing arrangements/etc.

5. ORGANIZATION

As previously noted, while the overall capital cost is not large - even including Esso's surface facilities the capital costs will be in the order of $6,000,000 - there are the complications of a diverse group of sub-projects, a new operating organization, and a clientele generally unused to gas. Hence, organizational complexity is much higher than the cost would indicate.

The following diagram generally outlines the planned key roles and organizational structure. In practice some roles may be handled by one man and in others roles may be split. In any event this organization must be in place at the outset of the Feasibility Stage. The requisite skills will probably come from 3 to 5 consulting organizations.


IPC MANAGEMENT
Program Manager
General Co-ordination
Esso Management Liaison
Senior Government Liaison
Program Control
- Monitoring
- Planning
- Cost Compilation
Marketing Consultant(s)
Demands
Rate Structures
Customer Rapport Development
Appliances (Meters)
Project Facilities Co-ordinator
Operations Consultant(s)
Staffing
Training
Operations Concepts
Support/Services
Facilities/Equipment
IPC Corporate Co-ordinator
Financing
Policies /Guidelines
Organization
Insurance
Overheads
Specialists
Geotechnical Consultants
Environments' / Permit Consultants
Transport (N CL)
Survey
Field Engineer
Facilites
Esso Technical Interface
Field Access
Communication
Pipeline Consultant
Pipeline
Permit (p.l.)
Esso Crossing
Terminal
Metering
Propane/Air
Buildings
Service Facilities/ Equipment
Corn (with field)
Distribution
Meters
Distribution Grid
Customer branches

6. COSTS

Table 6-1 outliness the expected costs of the Feasibility Stage exclusive of:

IPC/IDC internal costs
Major permit application and all hearing costs
Geotechnical testing (if essential at this time)

It must be noted that the estimate is preliminary and subject to:

Scope changes due to Scoping Study
Scope changes due to market scenario used as base
Scope changes due to drilling program
Extras relative to major permit applications
Extras relative to any essential geotechnical testing

The breakdown of Table 6-1 is, to some extent, arbitrary as scopes and roles will overlap somewhat. But the totals are considered sufficiently accurate for budgeting purposes.

TABLE 6-1
PRELIMINARY ANALYSIS OF
FEASIBILITY STAGE COSTS
(Excluding IPC/IDC Staff)
(dollars)

	Planning	Corporate	Marketing	Operat ons	Project (b)(c) Field Terminals	Pipe ine	D stribution	Manag	Totals (b)(c)
ersonnel									
Senior	5,000	4,000(a)	15,000	4,000	12,000	7,000	8,000	8,000	63,000
Intermed.	--	--	3,000	--	10,000	--	2,000	--	15,000
Junior									
Tech.	--	--	5,000	--	4,000	2,000	2,000	2,000	15,000
Other	2,500	--	1,000	250	1,500	1,000	2,000	1,000	9,250
Sub-Tota	7,500	4,000	24,000	4,250	27,500	10,000	4,000	11,000	102,250
xpenses									
Commun.	100	300	300	50	200	100	100	500	1,650
Travel	--	1,300	3,000	1,300	1,600	1,300	2,500	2,500	13,500
Computer	500	--	300	--	200	200	--	--	1,200
Misc.	100	100	200	100	100	--	100	200	900
Sub-Tota	700	1,700	3,800	1,450	2,100	1,600	2,700	3,200	17,250
OVERALL TOTAL	8,200	5,[illegible]00	27,800	5,700	29,600	11,600	16,700	14,200	119,500

NOTES: a) Financial consultant
b) Major permit applications/hearings extra
c) Geotechnical testing extra

7. INITIATION

The organization and participants of the Feasibility Stage is now being established, and will be defined well in advance of the anticipated starting date of mid to late February.

PRELIMINARY ASSESSMENT

OF

TUKTOYAKTUK REGIONAL NATURAL GAS SUPPLY SYSTEM

PREPARED **FOR**

VAN MEURS & ASSOCIATES LTD.

OTTAWA, ONTARIO

BY

RTM ENGINEERING LTD.

CALGARY, ALBERTA

682P - JULY, 1985

RTM

TABLE OF CONTENTS

1. INTRODUCTION

At the request of Dr. Van Meurs, RTM has prepared this brief analysis of gas sales potential and likely system scenarios in the Tuktoyaktuk region.

Electrical generation and heating sales potential only are considered herein, other potential uses being considered minimal in the short term.

This analysis assumes year-round gas supply from non-associated gas reservoirs, possibly supported by associated gas over a 100-day production season.

This report is intended to provide preliminary background for consideration of field ownership formats and related matters. Having taken only three elapsed days to develop, it should not be considered definitive but rather directional only. Further study will be needed relative to each aspect of demand and system.

Data were not available from Esso for Tuk area fuel uses, but Dome and Gulf supplied data. Gulf also provided demands for offshore uses.

2. BASES

2.1 Gas Sources and Compositional Data

(a) Gas Production

from 3700 foot gas rich formation
> 1300 PSIG at wellhead
> 99% methane (Esso analysis)
No H_2S, CO_2 <2%
Saturated with H_20
Availability > 3 MMSCFD (test had 6 MMSCFD with reduced choke) .

(b) Oil Production

300 SCF/BBL of associated gas - average
5000 BPD of crude average
100 day season
Sweet - no H_2S, little/no $C0_2$
Heavy hydrocarbons present (equilibrium)
Saturated with H_20

2.2 Potential Demands

(a) NCPC

- Data from Dave McGinnis, NCPC Edmonton

- Tuk electricity now from Inuvik except in emergency at Inuvik, or on Inuvik to Tuk 69 KV transmission line.

- Current winter peak 1600 to 1700 KV. Average 1000 KW, summer peak 1200 to 1300 KW. Average 700 KW. Supply generally just to non-oil company users.

- Fuel costs at Inuvik:
  Base load - Res. Fuel, 33¢/l. Two slow speed (old) diesels.
  Peak load - P40, 40¢/l. Two high speed GMD diesels.

Tuk standby capacity (with P50 at 41¢/l):
2 at 750 KW, Caterpillar diesel
1 at 600 KW, Caterpillar diesel (fairly new)
Not enough capacity to supply oil field and crude transfer loading needs.

Supply to Inuvik not considered in depth - see Appendix B.

Note that Inuvik to Tuk power line passes just west of Tuk oil and gas fields (as well as Parsons Lake fields to south west of Tuk) .

Fuel costs allow for federal subsidy to diesel fueled generating facilities.

- Inuvik and Tuk to have northern diesel generating plant electricity costs if current proposals to NEB go ahead - up to 40% above old ones.

Existing diesels at Tuk can be converted but must derate to about 65% of above.

(b) Townsite

Data from Al Hartman, NWT government in Yellowknife.

P50 purchases for Tuk now 2.8 to 3.0 x 10^6 l/year, generally covering all but NTCL and oil companies.

- 1984(?) breakdown (current prices)

Diesel Non Motive	70,000 l (3%) , 41¢/l,	NCPC
Diesel Motive	655,000 l (24%), 62¢/l,	fed & NWT taxes
Diesel Heating	1,950,000 l (73%), 54¢/l,	no taxes
Aviation	Use not allowed at Tuk as specification Jet A available.	

Houses heated except for summer - generally full rate, vary temperature by opening windows and doors.

Prices subject to change in October, 1985.

(c) NTCL

No direct contact but operate 120(?) man camp each navigation season.

(d) Oil Companies

Dome (Dave Rudd)

Centralizing generating capacity at base-line to airport, shutting down generator there and also one at fireball.

Approximately 22 gph November through April for electrical generation and 24 gph rest of year. (915,000 l/year.)

Operate 400 HP boiler (13,400,000 BTU hour) April, May, part of June, part of September, October. No ready data on consumption. RTM assumes average of 3.3 x 10^6 BTU/hour annual average.

Gulf - Gulf currently use 12,000 BPY of diesel/heating oil at Tuk and expect this to continue. No breakdown on fuel use provided. (1,910,000 l/year.)

(e) Oil/Gas Consumption

Oil Delivery:
Canuck estimated $18,500/year in fuel costs for 6000 BPD and 90 day season, including motive power, at $3.50 /gallon. Current cost about $2.45. Hence, RTM assumes $13,000/year cost ≏ 24,000 litres ≏ 36 KW (feels low) . Use 50 KW.

Oil Production:

Treating @ 15000 BTU/BBL	=	75,000,000 BTU/day
Building & Misc. Heating ($glycol/H_2O$)	=	25,000,000 BTU/day
Flare pilot	=	25,000,000
Heating total		125,000,000
Electrical - 150 KW average		

Above only over 100 day period.

Note that NCPC does not have generating capacity to supply above on other than interruptible basis. Gas Production - Non Associated gas - building heating and glycol regen fuel only 500,000,000 BTU/day. Associated gas - electricity 100 KW.

(f) Gas Delivery

- Canuck assumed 4" line operating at 200 PSIG to deliver 2 MMSCFD. Line specified for 300# flanges, OK to about 700 PSIG. (Line size and flange spec same for oil line.)

Materials	500,000
Construction	400,000
	$900,000 installed

Note for full year operation spec may be higher and add about 6.5 to 7% to above. A $1,000,000 figure for the gas line is assumed herein.

The above assumes a maximum inlet temperature of +35° C in summer and +18° C in winter - this results in thawed bulb around gas line all year for 1 to 2 KM. RTM believes this assumption needs review specific to soils in region of field.

(g) Approximate Engine Efficiencies

Diesels assumed as	10,000 BTU/KWH (on oil)
Gas Turbines - simple	16,000 BTU/KWH (on gas)
Converted diesels with internal heat recovery.	12,000 BTU/KWH (on gas)

Total - Average -	366.9 (1.01)	497.6 (1.36)
- Peak -	-- (2.03)	-- (2.70)

The peak load factors are to some extent arbitrary and ALL data must be confirmed.

Drilling rigs are not included but these could take up to 0.5 MMSCFD each and, hence, need to be considered in future analyses.

A 5000 topping refinery will take in the order of 25,000 SCFD - 0.60 MMSCFD - during its operating season. (However, some of that heat could come from gas turbine waste heat, if avail able.)

As accessing Esso is much more expensive than getting to, say, Dome, more work is needed to see if Esso fits into the potential markets. Hence, for economics the low case is suggested to be conservative at this time.

(h) Replacement Fuel Value

	Assumed Current Fuel Cost c1 l	Assumed Current BTU/KWH	Approx. Current Cost/ Million BTU'S	Gas Replacement Value $/mscf @ 12,000 BTU/KWH (Converted Diesels & Hi Effic. Gas Turbine)	16,000 BTU/KWH (Low Effic. Gas Turbine)
NCPC Generators					
- P50 (Tuk)	41*	10,000	11. s0	9.60	7.20
- P40 (Inuvik)	40*	10,000	11.20	10.00	7.00
- P40/Resid (Inuvik)	36*	10,000	9.50	7.90	5.90
- Resid (Inuvik)	33*	10,000	8.40	7.00	5.25
Oil Co. Generators					
- P50	41***	10,000	11.50	9.60	7.20
Town heating	54	--	1s.10	@ same fuel efficiency 15.10	--
Oil Co. Heating	54°*	--	15.10	15.10	•

• After Subsidy
0 Actual cost may be slightly lower.
• Oil company electrical fuel probably higher in cost - NCPC figure used but it is net of all distribution costs. Oil company heating fuel probably lower due to bulk buying. Average "feels" OK. The tax and subsidy situations are not fully clear and are very complex.

The above table does not allow for any capital charges. Operating costs, aside from fuel, should be no more and in most cases less than with current fuel cost.

Conversion costs are not major except for town heating where new appliances likely.

Prices shown are subject to change this fall.

In practice if a conventional low efficiency gas turbine is used its waste heat will likely be at least partially recovered for heating. Hence, demands should be based on the 12,000 BTU/KW figure.

3. DEMAND PROJECTIONS

Town needs are expected to continue to increase and a 1988 demand 15% above 1985 is assumed herein. Oil company use data available has not been of good quality and future consumption patterns are not defined. Hence, high and low scenarios are provided relative to oil company use.

	------- LOW -------			------ HIGH ------	
Electricity - KW	Annual Avg.	Displaced Fuel $	(Fuel) (Value)	Annual Avg.	Displaced Fuel $
NCPC	1,100	912,000	(36¢/l)	1,100	912,000
Oil Companies	800	828,000	(41¢/l)	1,200	1,242,000
Oil Line & Field	55	55,000	(41¢/l)	60	60,000
Gas Field	5	5,000	(41¢/l)	10	10,000
Other (al low)	20	20,000	(41¢/l)	30	30,000
TOTAL	1,980	1,820,000		2,400	2,254,000
Peak	(4,200)			(5,000)	
Heating - BTU/hour (x 10^6)					
Town	10	1,327,000	(54¢/l)	10	1,327,000
Oil Companies	7	929,000	(54¢/l)	10	1,327,000
Oil Field	*		*	*	
Gas Field	*		*	*	
Other [al low]	1	133.000	(54¢/l)	2	266,000
	18	2,389,000		37	2,920,000
Peak	30			37	

The above assumes the oil companies paying the same prices as NCPC or NWT government customers. This may overstate the displaced fuel values. Residual fuel may displace diesel at some oil company facilities (as well as in their fleets) .

* Fuel available free in field.

Natural gas equivalent demands, assuming the 12,000 BTU/KWH rate, are estimated as follows in 1988:

		LOW		HIGH	
		mmscfy	mmscfd	mmscfy	mmscfd
Electricity	- average	208	(.57)	252	(.69)
	- peak	- -	(1.21)	--	(1.20
Heating	- average	158	(.43)	193	(.53)
	- pe*	- -	(.72)	--	(.89)
Total	- average	366	(1.00)	445	(1.22)
	- pe*	--	(1.8)	--	(2.0)

If the Tuk field continues to develop the above figures will prove low:

- Drilling rigs will use gas (Gulf is planning this route at Parsons Lake) .

- Added population and service industry activity will result.

- Topping refinery will use in order of 750,000 scfd (allowing for electrical needs) .

The drilling rig activity would be specially important as a typical rig could use in the order of 500,000 scfd.

Peak demand seasons appear likely to be in June and September when oil industry activity is high and weather cold enough to require some heating. But more analysis is needed to properly identify peak flows as well as timing.

4. SYSTEM SCENARIOS

In the field the following options are available:

I Associated gas only - 1.5 x 10^6 SCFD average, 100 days year only
II Shallow gas only - Available as needed year round
III Associated & Shallow Gas - Available as needed year round

In order to keep oil pilot systems costs low, associated gas will likely not be recovered for other than lease fuel.

A pipeline to town is common to all scenarios. Canuck's 4" line "feels" OK but even if operated at 600 to 700 PSIG - as recommended by RTM - will have only an hour or so of surge capacity. Additional loads such as that of the topping refinery may result in a 6" line, or change to 600 PSIG flanges allowing operation in the 1400 PSIG level. In any case the field system must be able to handle significant load rate fluctuation.

On the town end we have the following options:

(a) Sell to NCPC only.
(b) Sell to NCPC and oil companies. (Latter will use for fuel as well as generation) .
(c) Generate electricity and sell to NCPC.
(d) Generate electricity and sell to NCPC and oil companies.
(e) Heating town via distribution system.
(f) (a) + (e)
(g) (b) + (c)
(h) (c) + (e)
(i) (d) + (e)

A hot water heating system (via gas turbine exhaust) might be considered in future studies, but was not considered here.

In cases (a) and (b), existing diesels can be converted but capacities must be derated. This means new capacity at NCPC, at least. Also NCPC would have to add staff for routine, rather than emergency, Tuk generation plant operations. The Inuvik to Tuk power line would likely be used for oil field supply - with added generating capacity - and for emergency supply to Tuk.

In cases (c) and (d), existing diesels could well be left as standby capacity along with the Inuvik to Tuk power line. Due to available diesel capacity these alternates may not return much more revenue than displaced fuel. A new full reliability system would back out maintenance costs of existing machines, some of which might be sold. Also NCPC's apparent need to expand Tuk generating capacity in any case would be eliminated. A total generating capacity in the order of at least 6,000 KW would appear required.

In case (e) a local distribution system is needed, including heating appliance replacement.

NCPC have good guidelines for negotiating off system generation input to their system except for price - the key element.

For the various cases the following gas' values are calculated NEGLECTING added capital beyond the gas supply system in all cases.

	LOW+		HIGH+	
	Nat'l Gas Equivalent mmscfy	Average Displ. Fuel Value as $/mscf	Nat'l Gas Equivalent mmscfy	Average Value $/mscf
a) NCPC only	116	7.90*	116	7.90*
b) NCPC + Oil Cos.	261	10.20*	330	10.50*
c) Gen. for NCPC Mkt.	116	7.90*	116	7.90*
d) Gen. for NCPC & Oil Cos.	200	8.70*	243	8.90*
e) Town Heating	88	15.10	88	15.10
f) (a) + (e)	204	11.00*	204	11.00*
g) (b) + (e)	347	11.50*	418	11.50*
h) (c) + (e)	204	11.00*	204	11.00*
i) (d) + (e)	288	10.60*	331	10.50*

Notes:

+ Oil field and miscellaneous demands neglected.
• Before new generation equipment charges.
°Assuming new generation requiring 12,000 BTU/ KWH.

The lowest valuation is based on NCPC Inuvik fuel costs and includes credits for the federal diesel for generation subsidy. However, power generation costs are not allowed for. It appears that NCPC require major changes at Tuk if expansion of demand continues as they cannot even now supply any new customers.

Also, there is some question of the Inuvik to Tuk power line handling added peak loads and its ongoing viability. It would thus appear that disregarding generating costs may be a reasonable assumption relative to NCPC. However, the same is not true relative to the oil companies. But their use of a lighter and more expensive average fuel that at NCPC Inuvik increases the potential netback.

5. GAS SUPPLY SYSTEMS

The associated gas can only be considered as a supplemen'al source in any case:

- Only available for 100 days a year
- Variable even during that period
    - Production rate variations
    - Variation in GOR - wet, formation, rate, etc.

Associated gas is assumed used for oil production heating needs only, hereafter except for a brief discussion on processing needed for its use.

The pure methane non-associated gas needs only drying before use. As noted in Section 2, chilling might be considered necessary (but outside the summer oil shipping season as the oil line will control adjacent soil temperatures) .

A very simple well head dehydration scheme is envisaged using a standard TEG (tetra ethylene glycol) gas assisted dehydrator to provide a dew point of -20° C or lower. The glycol system will use product gas to drive the glycol pumps, for instruments, as stripping gas and as fuel. Thus the system will be essentially contained. It is proposed to specify the glycol system for the formation pressure and to reduce gas pressure to pipeline levels after the glycol contactor.

The glycol system will be skid mounted in a building (except for the burner and stack of the fired regenerator) . Electricity for lighting, service use and tracing (for startup of wells to glycol piping) will be provided from the oil field system.

The glycol system complete will cost about $300,000 installed.

Should a chilled gas be required, the addition of a gas to gas exchanger and a separator will allow use of the expansion chilling to get to the desired <0° C temperature. Expansion by itself will not give the required temperature. This will add in the order of $70,000 to the above cost.

As noted before, it is recommended that the gas line to town operate near its maximum design pressure to maximize inventory and minimize pressure drop.

Associated gas is rich in heavier components and low in pressure. An extra 150 KW or so of compression and refrigeration electrical needs will be required for its recovery and purification. Normally, this can be justified due to added liquid recovery, but probably not in the pilot scheme proposed here. Associated gas can, however, be used for most lease needs, backed up by dry gas from the regular supply system.

In order to provide proper security of supply, more than one gas well will be needed, although only one will be needed at a time. It may prove easier to have glycol units at each well, rather than a central unit as discussed above. This would add $300,000 or so of cost, but eliminate possible freezing in a well to glycol transfer line.

It appears essential that there be backup at the town end. A propane/air system is proposed at this time - another $500,000 or so. The new gas turbines could be set up for diesel fuel - gas and diesel - if desired to provide the necessary generating reliability. More work is needed in this regard.

Thus the overall system recommended is as follows:

Glycol Dehydrator	$ 300,000
Pipeline to Town	1,000,000
Propane/Air Backup	500,000
Total	$ 1,800,000

System development, permitting and project management costs will push that total near $2,200,000.

Operating costs for this system - exclusive of any special well costs - are estimated at $250,000 a year, largely for 2 or 3 operator/maintenance personnel.

Gas turbine based electrical generation facilities will cost in the order of $1 ,500/KW, with operating costs in the order of $100 to $150/KW/year exclusive of fuel costs in the 4 to 6 MW size range.

6. CONSTRAINT REVIEW

(a) NCPC is a key element!

- Political organization and pressures!
- Slow decision making
- Have trouble getting good operators
- Tuk generating plans undefined (?)

(b) Regulatory

- Confused
- NCPC appear to relate to NEB
- Territorial utility board?

(c) Oil Companies

- Will try to get lowest cost fuel and electricity possible
- All appear to be in state of some confusion as to direction of Tuk 'operations in future
- Long distance - gas and electricity to Esso

(d) COGLA, et al

- May argue for associated gas recovery (preferential use) .

(e) Heating Market Penetration

"Free" gas furnaces may be needed to sell gas use.

(f) Topping Plant competition

- Naphtha surplus to regional needs could be used for gas turbine fuel - competing with gas from field. Naphtha prices are dropping.
- BUT naphtha can be shipped outside area, gas can't.
- Residual fuel will compete with gas (Tuk / Inuvik generating balance) . But large residual fuel needs for offshore fleets foreseen. (Gulf noted ability to switch most ships.)
- Residual fuel could be used in local electrical generation via slow speed marine diesels or steam systems and for oil company heating needs.

- Topping plant will produce P50 but generally this will be desired product with highest price. But topping will compete with gas sales in town heating. Gas appears likely to be much less costly than P50 for most local heating needs.

- 1,000,000 scfd of gas is only equivalent to about 170 barrels per day of topping plant products; hence, of only minor impact on topping plant economics.

7. CONCLUSIONS AND RECOMMENDATIONS

The basic cost of gas delivered to the Tuk terminus of a gas line laid parallel to the proposed oil line is expected to be about as follows:

	Annual	Bases
Gas Wells	$ 550,000	$1.50 per mscf (by Esso et al)
Gas Field & Line Operating	250,000	
Gas Field & Line Capital	550,000	@ 25%/year of $2.2 x ,06
	$ 1,350,000	

Generally these costs will not vary much over the range 0.5 to 3 mmscfd average.

The cost of delivered gas is thus estimated at $3.70 per mscf at an average rate of 1,000,000 scfd. The above allows for no significant local distribution systems - Gulf and Dome will, however, be quite close to the line.

Expanded electrical generation capacity is needed in Tuk to handle enhanced population and economic activities. An oil pilot project and associated gas development will increase generation needs in their own right.

The Tuk NCPC plant is undersized by normal standards as capacity with one machine out of service is well less than even current town peak needs.

NCPC appear ambivalent about the future of the Inuvik/Tuk power line, and sufficient standby generating capacity is needed at Tuk to provide power in case of line outage in any case.

Most Tuk generation capacity can be converted to gas but at 30 to 35% capacity reduction. The cost of conversion is relatively low compared to new generating equipment.

The NCPC Inuvik plant's use of residual fuel and P40 sets the low value for fuel as long as a tie line exists to Tuk that could be displaced by natural gas.

In all uses some added costs are involved before the final user gets the energy form of his choice:

Electricity	(a)	Conversion of existing plus added capacity
or	(b)	New central generating plant supplying all users
Heating	(c)	Town distribution systems and appliance replacement
and/or	(d)	Oil company boiler system revisions

As the basic cost of gas is 50% or less of current fuel costs there would appear sufficient margin to pay for (a), (c) and (d) changes, in virtually all potential uses. (This study has not examined this aspect in any depth.)

A gas system will compete with a topping refinery's products but due to the small volume involved this should not be serious. The topping refinery will add to gas sales during its operating year.

A new central power plant appears to need further study as the capital charges may not make the resulting electricity attractive to the oil companies. Peak power needs in particular need to be much better defined.

Further, more in-depth study appears warranted on all aspects of the gas supply and utilization system. Such a study should consider an IDC franchise for both electricity and gas in the Tuk area, interfacing with NCPC via the Inuvik/Tuk line. NCPC preliminary negotiations should be considered as part of such work in order to well define their starting points and political pressures. Analysis of the fuel pricing structure in the Inuvik/Tuk region will be an essential part of future studies.

APPENDIX A

INUVIK SALES

A base load of 2000 KW or more might be exportable to Inuvik over the existing power line. (A widely fluctuating rate is not anticipated due to line limitations and the availability of peaking diesels at the Inuvik end.)

Capital costs would increase at Tuk by roughly $3,000,000 - slight field additions but primarily generating capacity.

The available revenues would only be the cost of fuel displaced at Inuvik - residual fuel oil. The value of this at the current subsidized rate would be about $1,500,000 a year. (NCPC will have slightly lower maintenance costs at Inuvik but generally their costs will change only with respect to fuel.)

At the added production rate overall, the basic gas cost to generation would drop to the order of $3.20 /mscf. Incrementally the additional gas would only cost in the order of $1.60 to $1.70 /mscf.

Only at the latter rate would this scheme appear to be attractive. But more work is recommended in this regard, especially as it can reduce the fluctuations in Tuk gas production and electrical generation significantly.

The possible development by Gulf of the Parsons Lake field will provide Gulf the same opportunity (as well as the potential to supply some Tuk demands) .

NOTES

RE

TUK GAS AND REFINING

PREPARED FOR

VAN MEURS & ASSOCIATES LTD.

BY

RTM ENGINEERING LTD.

SEPTEMBER, 1985

TABLE OF CONTENTS

1. INTRODUCTION

These notes have been prepared at the request of Mr. Pedro Van Meurs of Van Meurs and Associates to provide background in certain" areas of IDC development and/or negotiations relative to oil and gas in the Tuktoyaktuk area.

To date more than sufficient gas reserves have been identified to supply all Tuk area needs for power generation and heating. This winter's drilling program will define crude reserves in the area sufficiently to allow decisions on refining (and gas distribution) in the spring of 1986.

The Northern Canada Power Commission will play a major role in the success of any local gas and/or oil local utilization project. Unfortunately our normal contact was on vacation, and Mr. Bruce Christie, Acting Assistant General Manager - Corporate - who is apparently the most appropriate initial contact was in the north all week. His Edmonton office telephone number is 465-3377.

In this report there are various assumptions that may not be realistic and need change. These have a "*" in the margin. It is not exPected that they will significantly effect the bottom lines for gas or refining. However, these notes were prepared in one week and are based on earlier studies, in-house data and selected telephone contacts. Data herein must be treated as preliminary and subject to change.

2. GAS

2.1 General

Two previous studies reviewed a major gas/condensate development and a second a gas supply system for the Tuk area. This expands on the latter and should be used in conjunction with it. Here the Tuk town distribution system is considered along with other portions covered in the previous report. Some changes will be evident in this report.

Esso site demands are treated separately due to questionable economics.

IDC ownership and operation of the gas line and distribution system is assumed. Generally this section does not consider refinery gas system synergy. (Nor are oil field gas needs and/or associated gas availability considered.) While transfer of gas is assumed at the wellhead, this results in IDC operation of dehydration facilities. This is
* normally frowned on and can impose legal problems relative to gas supply failures. We have a concern about production starting and stopping as well as low flows due to the permafrost zone. This may need methanol or glycol injection or hot gas recycle. We recommend Esso operate the dehydration facility (especially if they are operating the oil field) and the IDC buy after dehydration. However, the opposite is assumed here.

* An early IDC application for a gas franchise permit for the Tuk area is recommended to protect the area in any case.

2.2 System Concepts

Figure 2.2 outlines the concepts assumed in this study. At this time the Tuk distribution system has not been laid out nor a detailed analysis made of number of connections and by types of users.

From the earlier report:

- More detail is provided,
- Second wellhead dehydrator added (assumed better than hot line, from one well to a single dehydrator), and
- Odorant system added (left out before).

If a line to Esso is economic a cross bay routing from east of the air strip appears a more realistic route than around the bay.

The following organization is anticipated for the gas utility, based on experience elsewhere in small systems:

Gas System Manager

Field Operator
(Truck)

(backup)

Service Man
(Truck)

Ass't Service" Man
(also meter reader)

Contract personnel on call
Pipefitter/welders
Electrician
Equipment Operators

Office Manager

Accountant
Clerk
Sales/Warehouse
Buyer (truck)

A technical service agreement and loan for a year or two of an acting manager from a gas utility company, such as ICG, is recommended. Such a company will also provide assistance and training during the construction period.

A sales room (appliances), warehouse (appliances, meters, etc.) and a repair room will be needed in addition to an office. Other companies such as the Bay and plumbers, should be encouraged to carry appliances (and this may obviate the need for an appliance sale facility).

New buildings will be expected to pay for their own connections, but connections to existing buildings is covered here in capital. Hopefully most users will see enough gain to buy their own appliances, but here they are assumed to require some subsidy to convert.

Operating Costs (cash)

Personnel	With/Without Oil Line	
Personnel	450,000	
Overheads, taxes, insurance etc.	200,000	
Supplies and sub-contracts	100,000	Excludes appliances and new connections
Franchise fees	50,000	
	800,000	

Demand/Revenue Analysis

	Max.Rate Case				
	mmscfy	Max. UnitRate* $/mscf	Max.Rev. $M	Revenue @ $2 less	Now Pay about
Generating - NCPC	116 (33)	6	696	464	912
- Oil Cos.	84 (24)	8	622	504	1757 or
Heating - Oil Cos.	62 (17)	8	496	372	less
- Town	88 (25)	10	880	704	1372*
- Misc.	5 (1)	10	50	40	
	355		2,794	2,084	

* Set at 80% of competitive fuel except town at 67%.

Note that the lower rates may be offered large single point users, but only the higher rate on the town end (although the N.W.T. housing authority will be a large buyer in its own right).

The operating costs are still high by southern standards, and there may be some savings there. The town distribution system estimate is only ±30% and the supply system is a little bit better. Hence, there is some capital upside risk.

For the maximum revenue case, cash flow before income and sales taxes is about $1,994,00. If capital is charged at 25%/year - 6% depreciation on supply and distribution with meters at 20%:

	With Oil	Without Oil
Cash Flow	1.994	1.994
Less capital costs	1.075	1.650
Excess	0.919	0.344

At the alternate revenue case, again before income and sales taxes, cash flow is about $1,284,000. This appears less than desirable in the "without oil line" case, but still OK in the "with oil" case - assuming no sales taxes apply!

Thus the key variables appear to be:

- Will there be any N.W.T. sales taxes
- What rate of return does IDC require
- What are likely ups and downs of gas sales.

* Early discussions re any N.W.T. sales tax on gas sales appears essential.

* Demand data need to be firmed up as well before a go/no go decision is needed - this will require discussions/negotiations with all oil companies and the NCPC.

2.4 Gas Schedule

Canuck indicated that with a March start the gas pipeline could be in place by the following end of May. The distribution system could probably be in place by that time if all jurisdictional aspects are out of the way and do not hinder the design and construction. The oil companies could probably move that fast to start using gas in mid-'87 but we seriously doubt NCPC could plan, design and build a new generating plant inside 18 months. However, as noted before, we were not able to get an opinion on this from NCPC.

If NCPC is to build a new station they must try to negotiate (with the NEB) special lower rates in an attempt to get oil company loads. Previously the oil companies would not give NCPC surety of long term demand and now they also have the added hurdle of an inappropriate rate schedule.

Consumer changeover cannot commence until gas is in place and virtually all users in a given area are signed up. (Gaps on a route can get expensive!) With several teams of "connectors" it may be possible to connect up most users in 1987 but most likely it will take until the summer of 1988 to complete the bulk (and even there will be the odd hold out).

We'd suggest the following program:

1985 - N.W.T. contacts re franchise and sales tax and franchise fee.

- Local discussion re system possibility.
- NCPC contact re their incentive needs, demands and timing.
- Oil companies re potential demands (ranges).
- Analysis of local oil and gas development on town.
- Upgrade supply and distribution concepts and costs.
- Develop business concepts in some detail.

Early 1986 - Franchise application and hearing, if needed.

- Tentative assistance contract.
- Manager lined up.
- Mapping, etc. in place re town.
- User contact program ready to go.
- Business and technical plan ready to go.
- Financial plan in good shape.

In order to get NCPC on schedule it may be worth while to subsidize studies they may need for a decision. Help to major local firms may also be needed to prepare them for a switch to gas.

At this time it would apper that the system would not be fully operative until mid-'88.

2.5 Esso

An added $1,000,000 could well be needed to supply the Esso site with a potential revenue in the order of $300,000 a year. Further work is needed in this regard. Esso will prefer to pay a transmission charge for their gas - this will not bring in much revenue - in the order of $60,000 on a prorated basis (for supply 1 ine only) assuming Esso pays for the line across the bay to their property.

3. REFINING

3.1 General

At this time the "refinery" is defined by a minimum case scenario that assumes only the '80/'81 demand levels exclusive of major oil company exploration activities for an area north of Fort McPherson, but excluding the P40 and P50 demands of the areas south of Inuvik. The latter are assumed to come from Norman Wells. Any other demands not met by a Tuk refinery are assumed met by Norman Wells or Alberta refinery products - e.g. gasoline.

Excess products are assumed barged to Norman Wells for blending with Norman Wells crude flowing south.

The closest crude assay is an old ('74) partial Myogiak 32° one which, accounting for weathering, is assumed close to the 33° crude found south of Tuk. (21° crude also found there is not considered here.) The Myogiak field itself lies just east of Tuk but apparently does not have enough reserves to be considered as the primary supply to a Tuk refinery.

Previous studies have considered the process concepts needed and those are not discussed here. Esso is assumed to own and operate the field gathering and treating facilities. This minimum case refinery must take full advantage of existing Tuk infrastructure including oil company tankage.

The demand case is as follows, with Tuk (Myogiak) crude yield also noted:

Jet B	66,000	BPY (20.5) demand	12% on crudes
P40/P50	94,000	BPY (29)	34%
P20X	51,000	BPY (16)	13%
Bunker	111,000	BPY (34.5)	48%
	322,000		

We expect the refinery to be organized somewhat as follows:

- Refining/Gas Division Manager
  - Secretary
  - Edmonton Co-ordinator
    - Senior Clerk
  - Sales Mgr.
    - Co-ordinator
  - Tech/Log Mgr.
    - Engineer
    - Clerk
    - 2 Lab Technicians
  - Mech. Mgr.
    - Instr/Elect.
    - Mech.
    - Millwright
    - Pipefitter/ Welder
    - 2 Trainees
    - Warehouse/ Toolman
    - Truck Driver
    - Clerk
      - Contract personnel on call
  - Process. Mgr.
    - 13 operators
    - Clerk
  - Admin. Mgr.
    - Accountants
    - Clerk
    - Buyer/ Expediter

3.2 System Concepts

3.2.1 Sizing

The refinery will be sized for a 200-day operation, allowing shut down during periods of no Inuvik/Tuk transport. Ratioing of P40/P50 production gives:

	Produce	Surplus	
Jet B	47	-19	
P40/P50	94	0	
P20X	51	0	
Bunker	188	+77	Ship to Norman Wells
Lt. Gaso & Losses	12	+ 6	(Lt. Gaso.)
Total Crude	392		

At 200 days this is equal to 1960 BPD. Hence, a 2000 BPSD refinery is proposed.

The refinery will be a minimum complexity topping refinery, except for special Jet B rationale.

3.2.2 Tankage Rationale

Crude — Two tanks needed to allow heating to melt out any water.

Allow 6 days total storage at refinery design rate to allow field startup and shut down on demand.

SLOP — Allow 1-1/2 days @ maximum crude rate.

Jet B — Need at least 100 days in system - Tuk and Inuvik.

Should have 40 days at Tuk to handle refinery S/D's.

Use Dome storage due to nearness to refinery.

Allow 3-day tanks at refinery to allow additive blending and testing before transfer to larger storage.

P40/P50 Set up to run directly to Dome or Gulf storage at Tuk but provide:

2 day tanks on site for startup and shutdown purposes.

Need at least 100 days in Tuk/Inuvik to system.

Of that 40 days at Tuk to handle refinery S/D's.

P20X P20 is a blend of a heavy fraction with some P40.

Due to use in shipping 200 days in system.

Minimum of 20 days at Tuk

Provide base stock tank at refinery (that can be blended up in emergency). Use small tank while blending.

Some NTCL and NCPC Tuk tankage might be used for final blend.

Resid Bunkers to sales - 5100 days in system at Inuvik (NCPC). Provide 40 days on site at Tuk.

Excess (to Norman Wells) - Norman Wells tankage need has not been checked - assumed OK. 200 days at Tuk needed (but some excess NCPC Inuvik storage might be used.

Note: All heated storage on site. Add 15% for unusable volume.

3.2.3 Loading Rationale

Tuk Provide truck loading as follows:

- Jet B - 1 arm - c/w pump, strainer, meter
- P40/P50 - 1 arm - c/w pump, strainer, meter
- P20X - 1 arm - c/w pump, strainer, meter
- Bunker - 1 arm (future)

These should be on site at refinery except that P40/P50 can use existing arms at other sites as backup.

Barge loading:

NTCL dock - bunker (heated)
- P20X - Jet B - P40/P50
Dome dock" - Jet B, P40
Gulf dock" - P40 or P50 only

* Consider two lines to expedite loading
° Emergency or for convenience

3.2.4 Scope of Refinery Project

Process Facilities:
- Desalter (one stage)
- Atmospheric Distillation Column
- Side Stream Reboil ed Strippers (2)
- Jet A Stabilizer
- Jet B Treater

Tankage:

On site	Crude	- 2 @ 700	=	14,000	Fltg Roof/Heated/Mixer
	Sl op	- 1 @ 3,000	=	3,000	Heater/Mixer
	Jet B	- 3 @ 500	=	1,500	Mixers
	Mid Dist	- 3 @ 1,000	=	3,000	one c/w heater
	P20 Base	- 1 @ 10,000	=	10,000	heater/insulated
	Bunker	- 2 @ 8,000	=	16,000	heater/insulated
		- 1 @ 80,000	=	80,000	heater/insulated
Total on site				127,500	
Tuk Offsite	Dome	-Jet B & P40	=	20,000	existing
	Gulf	- P40,P50,P20	=	30,000	existing
	Other	- Misc.	=	10,000	existing
				60,000	(to 100,000)

Inuvik	NCPC	- Bunker	As needed
		- P20/P40	As needed
	Esso	- Jet B, P40, P50, P20	As needed

Utilities:

Heating	Glycol/Water (2 levels) c/w heaters (2) gas fired
Cool ing	Glycol/Water c/w air cooler
Electricity	Gas Engine driven generators, 2 @ 400 KW each
Fuel	Refinery gas (to crude heater and glycol heater) Natural gas to refinery gas makeup and generation and G/W heater
Instrument Air	
Water	Evaporator
Fl are	c/w natural gas pilot and drain pot
Fire Water	Salt water pump, dry system. Mostly extinguishers.

Services:

Control Room	Packaged prefab building
Laboratory	Packaged prefab building (fits above)
Camp	NTCL existing c/w sanitary waste treating, etc.
Offices	NTCL existing space c/w sanitary waste treating, etc.

3.2.5 Economics

(Millions of 85$)

1. Capital Costs	$	Note	'83 Estimate
Field	0	By others	0
Pipeline	3.0	Canuck figure	0
Process	4.6		3.8
Utilities	5.0		5.9
Tankage & Inter.	5.5	Max. use, existing	10.8
Support Facilities	0.3	Most by NTCL	5.1
Shipping	0.3	Minor revs. only	1.8
Site Development	1.2	New onsite tankage bases	5.5
Engrg. Mgmt. Temp.	3.0	Temp. Fat. by NTCL	8.0
Contingency @ 15%	3.6		6.1
	26.5		47.0
Corn'g., Trg., Startup	2.0	Includes spare parts	7
TOTAL	28.5		

2. Operating Costs

Utilities	0.05	Plant gas fueled	0
Cat. & them.	0.08		0.05
Fuels, lubricants	0.02	Lubricants only	0.05
Maintenance	1.10		1.40
Other staff	1.70	Includes mktg, corp.	2.19
General expenses	0.8		0.53
Ins. & Taxes	0.45	Land/pit taxes only	1.49
Contingency	0.40		0.57
Total	4.60		6.28
Inventory cost	0.5	10% x 150,000 bbls x $30 (cr. & Proc's)	
Total	5.1		

3. Revenues (FOB Refinery/no Taxes)

Jet B	2.63	47,000 @ $56/bbl (3¢/1)°
P40/P50	5.64	94,000 @ $60/bbl (38¢/1)
P20	2.76	51,000 @ $54/bbl (34¢/1)
Bunker*	5.27	111,000 @ $47.50/bbl (30¢/1)°
Excess Resid*	0.77	77,000 @ $10/bbl (neglected light gasoline)
	17.07	

4. Crude Cost 6.90 392,000 @ $17/50/bbl

5. Return: 17.07 - 6.90 - 5.1= $\$5.07 \times 10^{6}$ on capital of about $29[xx] million

* Note that these are the same product - someone might argue NCPC should pay lower value.

xx Depreciation rate 25%/annum so no taxes for about 2 years.

I

3.2.6 Note re Value of Conversion

The table on the next page compares the above case to two cases using the total market (less major oil company exploration related). A hydrocracker has been assumed added to convert heavy distillates to primarily P50 (with a yield of over 100% of Jet B and P50). A small natural gas to hydrogen unit is also added to provide the necessary hydrogen; the two units will use in the order of 300,000 scfd of natural gas. Such units have been considered too expensive in small sizes, but here there are offsetting advantages in eliminating excess bunker tankage (heated and insulated). The unit here will only be in the order of 750 BPD, a very small unit - all skid mounted.

The hydrocracker case is-compared to a topping unit to meet the same demands. The hydrocracker based facility needs only 60% as much crude to satisfy local markets and provides very appreciable market flexibility.

Note these added cases were only prepared to see the effects of scale - doubling the size of the topping unit changes the ROI (simple) little. Even the hydrocracker improves ROI only marginally - flexibility is not very quantifiable in simple examples.

3.2.7 Schedule

The leading topping plant package vendor indicates delivery in the order of 10 months. He indicated a second hand North slope unit available a year ago, but we don't believe it's worthwhile to pursue second hand equipment until you're ready to go. Good equipment sells quickly. Crude units in the 10,000 BPD range will continue available, but at the 2 or 3kOO0 level a new unit should be assumed for now. Gas plant modules are running 7 months or less.

To those times must be added 1-1/2 to 2 months for inquiring and contract negotiation. Adding 1-1/2 to 2 months for engineering before that time brings us to 10 to 14 months before major equipment modules are in the field from a "go". (And this infers trucking via the Dempster.) It will take 3 months to connect up and commission. Hence, overall realistically we're looking at 15 months before a topping unit is operating.

BALANCES								
	Market		Base		Extended Market With Hydrocrack		Topping Only	
	Market MBBLS	Unit Value	Yield MBBLS	Revenue $MM	Yield	Revenue.	Yield	Revenue
Jet B	66	56	47	2.63	66	3.70	66	3.70
40/50	94	60 (262*)	' 4	4.64	261	15.66	262	15.72
20	51	54	51	2.76	51	2.75	51	2.75
Bunker	111	47.50	111	5.27	111	5.27	111	5.27
Lt. Gaso.	--	--	(6)	--	(13)	--	10	--
Excess	--	10.00	77	0.77	21	0. 21+	300	3.00
				17.07		27.59		30.44
Crude		17.50	392	6.86	4.65	8.14	770	13.48
NET REVENUE				11.21		19.45		16.96
Operating Cash Cost				5.10		8.3		7.3
Net before capital				6.11		11.15		9.66
Capital (%)				28.5 (21.4)		45.5 (24.5)		40.5 (23.9)

The lead time can be cut by doing the necessary engineering and getting bids before a “go”. However, good crude data are needed to firm up the spec for the topping unit.

Canadian shops appear likely to be busier next year than they are now; hence, deliveries may stretch a bit. Auxiliary equipment is generally not a problem with few big needs.

4. ASSAY DATA

The following operational data will be needed:

Gas
- Min/Max Flowrates per well, Allowable rates of change
- Temperatures, Bottom/Wellhead at various rates
- Pressures, shut in/wellhead at various rates
- Composition/water dewpoint/HC dewpoint

Oil
- Min/Max Flowrates
- BS & W/Salt composition
- "API fluctuations
- Light ends content

Gas and oil crude assay needs are as per the following Tables A and B.

5. TRAINING NEEDS

A handwritten memo advised re recommended training needs. Since then the gas and refining organization charts have been simplified. Further simplifications and position elimination may be anticipated - staffing feels high. All operational approaches need to minimize people needs and/or work at the site or in Tuk. For example, gas meters will be returned to the vendor for servicing.

Generally the training breaks into three phases and sectors:

a) Visits to other refineries, gas plants, etc. to familiarize staff with northern operations, northern climate concerns, northern materials availability concerns.

b) Formal courses

c) On-site training during startup.

With good people, even without a lot of experience, the latter is the most cost effective approach and has the best results.

Visits are largely confined to senior staff and those needing to know how others do it in their area and environment. In Esso's case the Norman Wells refinery itself appears to be a key site for operating and mechanical supervision, as well as lab staff training. But more breadth is needed in most cases than just one company's operation. (RTM recently had a problem when it turned out the plant operators supposedly training - a new RTM-hired operator did not even know the fundamentals of his own operation - a very common occurrence!) Esso will not be able to provide the sites for gas distribution people to visit and we recommend an early technical service agreement with a company operating small gas distribution systems - e.g. ICG - to provide training on actual systems and to provide system definition, construciton and startup help and training.

The Fairbanks North Pole refinery may make a good updating point for senior refinery staff, as well as North Slope topping units (Arco).

A Petroleum Industry Training School gas course is suggested for several gas side people relative to gas field operations. Otherwise formal courses are largley confined to vendor schools.

The onsite training program is the key to success. It should be tied into commissioning and startup operations. I'd envisage it going as follows for gas:

a) Selected technical advisers.

b) They arrange trips by senior staff to existing operations.

c) The advisor re construction trains local people as they inspect the construction.

d) A sales advisor works with system people to develop the maximum number of connections.

e) The service adviser recommends spare parts.

f) The three advisers stay until the system is working well.

g) One man may stay as manager for the first year or two.

In the case of the refinery, we envisage a slightly different route (which will also cover the field).

a) Hire division manager

b) Retain technical advisor group for a 3-year period.

c) As part of their service they set up commissioning startup and training program.

d) They provide Senior co-ordinator, training/safety specialist (e.g. C. A. Edgelow), Mechanical engineer and process engineer, and shift operators for first 2 to 3 months.

e) This group puts on formal one month training program for senior staff with 3 weeks for others. Generally this is aimed at operators, but all staff will be exposed. Mechanical trades will have on-site courses put on by vendors.

f) The team works with IDC refinery staff until the refinery is running well.

g) After that the various team members will be on call as needed.

TUKTOYAKTUK GAS PIPELINE STUDY

DECEMBER 1985

Prepared by:

CanuckGIE Engineering Ltd.
200, 200 Rivercrest Dr. S.E.
Calgary, Alberta T2C 2X5
Phone: (403) 236-6000
Telex: 03-826678

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

1.0 INTRODUCTION

This report incorporates the analysis and cost estimation for a 114.3 mm diameter pipeline from "H-30" well to a location on the outskirts of Tuktoyaktuk. The termination of the pipeline has been called the "tit y-gate" in this report. The pipeline length for the base case has been assumed as 10 km. Further cases, from 10 km to 5 km in 1 km intervals, have also had costs assessed.

All costs have been based on "in-house" information and verbal quotations from suppliers. Other data from previous studies on northern pipelines has been used in the preparation of the pipeline costs contained herein. The costs are based on present day values.

2.0 DESIGN CONSIDERATIONS

2.1 Route Selection

The routing was selected to be as depicted for a previous study for a pipeline from J-29 well to Tuktoyaktuk. There will be two basic differences which are as follows:

- the location of well H-30, the start point, will be approximately 3 km north of the 0.0 of the previous study.

- the termination of the gas pipeline will be approximately 4 km south of the termination point of the previous study. The termination point will be the outskirts of the town rather than the harbour.

This gives an overall pipeline length of 10 km.

2.2 Hydraulic Analysis

2.2.1 Objective

The objective of the study from a hydraulics aspect was explained by Mr. Van Meures to be the calculation of the maximum throughput possible for a" 114.3 mm diameter pipeline. It has been assumed that the pipeline will be installed below ground.

2.2.2 Design Basis

Properties:	methane	99.5
	ethane	0.5
	total	100.0

Density at. base conditions:	0.681 kg/m^3
Base pressure:	101.325 kPa
Base temperature:	$15^{o}C$.

Delivery pressure: (Tuktoyaktuk city gate station for furtrher reduction and introduction to distribution network]	690 kPa (100 psi)
Inlet temperature:	15°C.
Ground temperature:	0°C. summer -7.2°C. winter [mean average)
Ground conductivity:	1.7 W/m°C.
Depth of cover:	0.762 m
Pipe roughness:	0.0457 mm

On the suggestion of Mr. Van Meures, we have adopted a similar pipeline profile to the one described in Fig. 2.2 of our previous report. The only changes are that the sections at the start and end have been removed, in accordance with the details of Section 2.1 of this report.

In adopting a similar routing and pipe profile, we further propose to adhere to the same general geotechnical information provided for in the earlier study.

2.2.3

A hydraulic analysis was initially undertaken for both summer and winter conditions on the assumption that the gas pressure was to be regulated at the well head to around 2000 kPa (290 psi). Using this and other criteria, it was found that approximately 4.0 mmcfd (113270 m^3/day) could be transported through the 114.3 mm pipeline in order that the flow velocities remained within reasonable bounds.

It was felt, however, that this initial premise gave rise to a very inefficient system on several counts. Firstly, it would be more hydraulically and cost effective to operate the pipeline at high pressures, approaching 9930 kPa (1440 psi). Under this condition, more flow could pass along the line with flow velocities still below permissible levels. Secondly, all metering and regulatory equipment could be located together at the city gate, thus giving ease of construction and maintenance. Further, the high pressure regulator, low pressure regulator and ancillary apparatus could be fabricated along with the metering equipment on a single skid, thus giving a substantial cost saving.

Using this alternative and more realistic approach, it was found that flows of around 15-20 mmcfd (4250 00-566500 m^3/day) could be transported through the 114.3 mm pipeline assuming a range of initial pressures betweem 7000-9930 kPa (1 000-1440 psi). All the specified restraints would still be adhered to under this scenario.

The pressures at the end of the 114.3 mm pipeline would be in the 4000-7000 kPa range [6 OO-1OOO psi). At this point, the gas would undergo meterage and regulation to around 172 kPa (25psi). It is anticipated that the flow will pass through the following equipment:

flow regulator
heater
high pressure regulator (±7000 -- ±2000 kPa)
low pressure regulator (±2000 -- ± 200 kPa)
P.D. meterage
odorizer

Gravitometer, dew-point recording and gas sampling facilities will also be included in this equipment. It has been assumed that dehydrating equipment has been installed at the well-head.

Our major concern in the results given in the output for the selected flow rates was the high flow velocities through the pipeline. In our experience, gas pipelines operate with velocities in the 4-8 m/s range in genera!. As a maximum, we have assumed 10 m/s as an upper limit. For the high pressure condition, there was no definitive inlet pressure given and so we have assumed a range of inlet pressures between 7000 kPa and 9930 kPa which is the maximum pressure for fittings in the ANSI 600 category. The hydraulic analyses were undertaken using our "in-house" computer programs. The results are included in the Appendices.

2.3 Design Constraints

There are a number of factors that have an impact on the design basis for the pipeline. In addition to the parameters normally considered for conventional gas pipeline systems, such as throughput level and required pressure to overcome elevation and friction, there are conditions unique to northern pipelines which also influence construction techniques and timing, and require designs which are compatible with them. These principal influences are as follows:

a) The presence of continuous permafrost;
b) The extensive range of ambient air temperatures on an annual basis together with low minimum temperatures; and
c) The absence of an extensive infrastructure of roads and other transportation and communication facilities.

Construction techniques should rely predominantly on winter construction. This approach interfaces well with the summer shipping season, reduces the impact on the environment and facilitates access to the right-of-way.

2.4 Design Conditions

To facilitate construction as well as operation and maintenance for the pipeline system, reliance was placed on the following design principles:

a) use of standardized designs, sizes and construction techniques wherever possible; and
b) use of common equipment types and sizes.

2.5 Codes and Standards

The design and construction of the pipelines in the Northwest Territories can be governed by two government regulations. The two sets of regulations are:

a) Regulations regarding oi pipelines issued by the National Energy Board.

b) Regulations covering production facilities and pipelines issuedby COGLA.

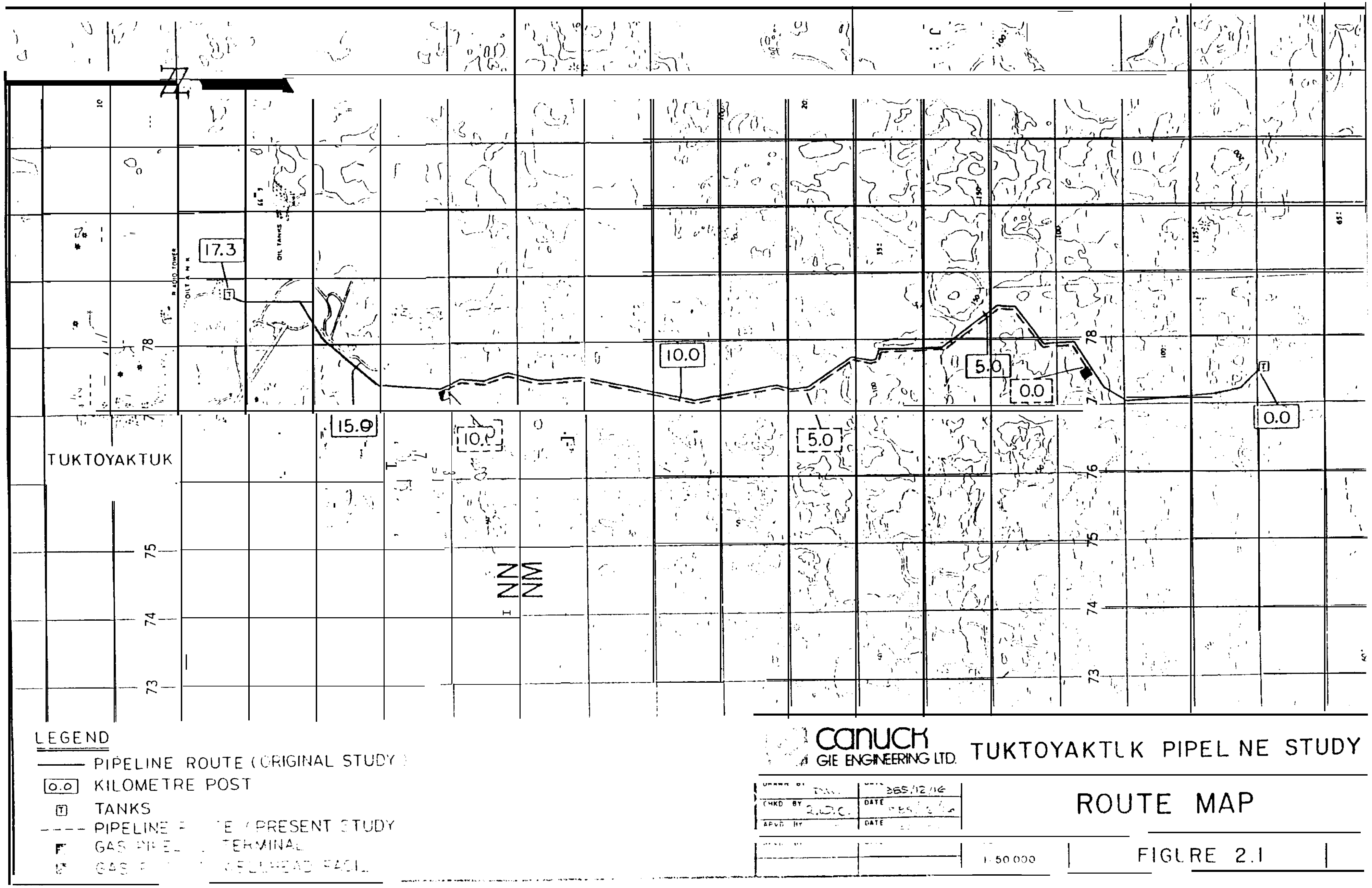
Both these agencies in their regulations make references to or request that the applicant follow relevant standards issued by CSA. Most relevant standards are CSA Standard Z245 covering steel pipe and CSA Standard Z184 covering gas pipel ines.

Additional to the above mentioned codes and regulations, the design and construction of the pipeline is affected by regulations and acts of different government agencies of all three levels of government..

A summary of the principal codes and regulations having the widest impact is provided in Table 2.2.

2.6 Reclamation

Reclamation does not pose a problem since seeds and fertilizers, suitable for the area, are commercially available. Also, sufficient knowledge regarding the proper mixes exists.



TUKTOYAKTUK
17.3
15.0
10.0
5.0
0.0
OIL TANKS
RADIO TOWER
78
76
75
74
73
LEGEND
PIPELINE ROUTE (ORIGINAL STUDY)
KILOMETRE POST
TANKS
PIPELINE ROUTE (PRESENT STUDY)
GAS PIPELINE TERMINAL
canuck
GIE ENGINEERING LTD.
TUKTOYAKTUK PIPELINE STUDY
ROUTE MAP
1:50 000
FIGURE 2.1

Climatic Region 11 - Marit

	JAN	FEB	MAR	APR
MEAN MONTHLY				
AIR TEMPERATURE (°F)				
- Maximum	-6.6	-11.0	-5.4	8.4
- Average	-14.4	-18.4	-12.5	1.2
- Minimum	-22.2	-25.8	-19.6	-7.2
PRECIPITATION (inches)				
- Rainfall				
- Snowfall	4	2	2	1.5
- Snowcover	13	10	12	12
WIND VELOCITY (miles/hour)	14	14	13.5	12
SOLAR RADIATION (Langley s/day)	0	30	165	390
DAYLIGHT (hours/day)	0	6.8	11.3	15.6

* Dates give the disappearance and appearance of permanent s
one inch of snow remaining on the ground.

TUKTOYAKTUK PIPELINE STUDY

TABLE 2.2
CODES AND STANDARDS

National Energy Board, Oil Pipeline Regulations
CSA Standard Z 184, Gas Pipeline Transportation Systems
CSA Standard Z 245.5-M1979, High Strength Steel Line Pipe Smaller than 457 mm in Diameter

API-6D-1974, Pipeline Valves
CSA Standard C22.1, 22.2, Canadian Electrical Code
ASME, ASME Boiler and Pressure Vessel Code
CSA Standard B51, Code for the Construction and Inspection of Boilers and Pressure Vessels

National Building Code
Canada Labour Code
Oil and Gas Production and Conservation Act
Territorial Lands Act and Territorial Land Use Regulations
Arctic Waters Pollution Prevention Act
Northern Inland Waters Act
The Board of Transport Commissioners for Canada, General Orders
CSA Standard 516-1969, Steel Structures for Buildings
Canadian Institute of Steel Construction, Structural Design
Government of Canada, Navigable Waters Protection Act
The Fisheries Act
The Migratory Bird Convention Act
The Land Surface and Reclamation Act
Canadian Oil and Gas Pipeline Regulation (COGLA)
Federal Clean Air Act, Ambient Quality Objectives

3.0 PIPELINE DESIGN

3.1 Pipeline

The pipeline proposed is buried and uninsulated containing the following main features:

Approximate cover of 0.762 m (since the permafrost in the area is ice rich, extra local fill material, approximately 30% of the excavated trench volume, should be installed as select backfill); and

A pipe wall thickness able to sustain a differential thaw settlement "of 0.6 m.

4.0 CONSTRUCTION

4.1 General Assumptions

The pipeline will be installed in the months of February and March with testing and commissioning occurring prior to spring breakup.

Al! materials required will he put into stockpile at Tuktoyaktuk in the summer prior to installation. Storage will be at NTCL yard (i.e. no special site preparation is required) .

Specialized pipeline equipment, not available in the north, will be moved in by road prior to the winter construction season.

Accommodation for the construction crew is assumed available in Tuktoyaktuk and will utilize caterers currently operating in the area. Handling of camp consumables will be the responsibility of the caterer.

Workcrews will arrive early in January when pipeline construction is scheduled to commence. A winter road is required along the right-of-way to allow movement of traffic and construction equipment. Work on the pipeline will proceed from north to south commencing with stringing and bending. The joints will then be welded and made ready for lowering into the ditch.

In order to minimize geotechnical concerns, the trenching operation will utilize a " rock-saw", wherever possible, but some areas may be found where ripping will be required. The pipeline will be lowered in and backfilled as soon as possible after the trench is complete. Additional backfill material of local soil needs to be worked into the existing backfill to allow for seasonal shrinkage due to thawing.

On completion of tie-in, the pipeline will be pressure tested to ensure its acceptability. The pipeline will be tested as one section utilizing air as the test medium.

4.2 Schedule

A schedule for a summer 1987 start-up of the pipeline has been assumed. The most critical schedule criterion regarding work in the far north is meeting the barging schedule. Available data from barge operators indicates that the last delivery to Tuktoyaktuk has been as early as September 23 and as late as October 5.

Transporting of material and equipment by truck via the Dempster Route is considered a viable option but would have a significant effect on the logistics costs. The Dempster Route would be available for heavy traffic from mid-December to mid-April which would facilitate the construction schedule.

Assuming that the line pipe would be barged to site, the last of the pipe would leave Edmonton September 1. Allowing one week for coating, all pipe would have to be rolled prior to August 24. Allowing three weeks for the preparation of the coils and rolling, authorization to purchase would be required by August 1. Financial commitment to proceed would be required on this date.

Allowing approximately two weeks to prepare specifications, quotes and to evaluate for recommendation, engineering work would have to commence in mid-July.

Pipeline construction would take place between mid-February and mid-April. This would maximize both weather conditions and daylight hours while completing the work prior to break-up.

5.0 OPERATIONS AND MAINTENANCE

Operations costs for the system have been calculated on an all year-round operating schedule. A full time manager/inspector has been included but it is felt that he will not be fully utilized on this small pipeline.

It has been assumed that, under normal circumstances, a 2-3 month period each year will be allocated for the annual maintenance of the pipeline. During this time, temporary labour and equipment will be brought in to undertake this work.

Allowances for vehicles, accommodation, communications and material consumables have been included as has the fuel costs for the system and an allowance for office support to the operations department.

6.0 COST ESTIMATE

6.1 General

The capital costs and operating costs were undertaken using similar concepts to those adopted in our previous study. There are, however, some minor differences in the way the costs were developed for this pipeline construction. Since this pipeline is of smaller length and size than before, we have incorporated a greater emphasis on the use of local labour and equipment wherever possible. At this stage, the details of the pipeline are of a preliminary nature as is the pertinent information to be used in the costing exercise. With additional time and more precise details, we fee! the estimate would produce a more accurate and confident result.

6.2 Cost Development

The scope of work with respect to the evaluation of construction and operating costs was as follows:

- undertake a cost estimate for a 114.3 mm diameter pipeline of length 10 km. The overall costs were to be subdivided into "fixed costs" which would be static for various lengths of pipeline within the 10 km-5 km range, and the "varying costs" which would be governed by the pipeline length.

- the cost estimate was to include the construction costs for the pipeline, a meter run and a pressue regulation station at the "city sate, " as well as the operating costs associated with the pipeline.

- undertake similar cost estimates for 114.3 mm diameter pipelines of lengths 9 km, 8 km, 7 km, 6 km and 5 km.

Initially, the construction costs were developed for the base case, which is the 10 km pipeline. This pipeline runs from well H-30 to the city gate of Tuktoyaktuk. The costs are given in Table 6.1.

The procedures used in the evaluation of this pipeline cost include the following:

- evaluate the route from information in previous feasibility studies and on 1:50,000 topographic maps.

- review geotechnical information and environmental considerations for the specific area.

- develop construction logistics details on the basis that as much of the equipment and labour as was practical would be utilized on the construction project.

- evaluate pipeline design and determine material requirements for pipe and ancillaries. It has been assumed that all pipe materials will be transported from Edmonton via Hay River to Tuktoyaktuk at the end of the barging season of the year prior to construction.

- determine representative costs for locally supplied materials.

- select the manpower, equipment and consumables which constitute the various crews involved in the pipeline construction. Further, evaluate the items of plant and labour which could be supplied locally.

- using the aforementioned data, extend all cost components in accordance with PLCA Union agreement., PLCA equipment rental rates and construction parameters for Arctic pipelining.

6.3 Direct Costs

Costs for major materials (i.e. pipe, coating) were based on verbal indications received from pipe and coating mills. costs for appurtenances such as valves, fittings, flanges, markers, test leads, etc. , have been included as an additional ten percent.

Transportation of material from the FOB point (assumed Edmonton] to Tuktoyaktuk has been included at current commercial rates of $15.25 per 100 lb. base, trucking to Hay River and then barging to Tuktoyaktuk via the Mackenzie River.

Construction costs were developed by selecting the personnel, equipment and consumables required to complete the work, and extending the cost components in accordance with applicable PLCA agreements. Contractor's mobilization costs were based on a winter move-in and move-out along the Dempster route. The cost per truck load from Edmonton to Tuktoyaktuk is estimated at $8000 per trip.

Subsistence at $135/day has been included for all contractor's personnel working on the project.

Fuel costs for the contractor's equipment has been included at 8% of the above costs, based on historical information. Contractor's overheads and profits are estimated as an additional 15% of the total construction cost.

6.4 Cost Adjustment for Variable Pipeline Lengths

In the construction of such a small length of pipeline, it is difficult to assess exactly how a contractor would produce his bid. In our 10 km base case., it has been assumed that the equipment used in the estimate is approaching the minimum possible for this type of project.

The manpower requirements were selected in an effort to optimize the overall construction costs. For example, it could be possible to increase the manpower, and the equipment for that matter, to reduce the duration of construction. This would give a much larger day rate for labour and equipment and a higher mobilization cost, but would decrease the duration. By doing this, it is felt that the best use of the labour and equipment is not being had.

Conversely, the labour, but not the equipment, could be reduced at the expense of a longer duration. Again, it is felt that this would not be cost effective.

In the preparation of the estimate for each of the other pipeline lengths, we have assumed the following:

materials are essentially ratioed to the pipeline length and as such the material cost will be factored against the material cost for 10 km length in direct proportion to the ratios of the pipeline lengths.

for most of the construction activities, the duration will be in direct ratio to the length, apart from the start-up and completion lags associated with each activity. Testing is the only activity where essentially the same time must be spent independent of the line length. The 10 km length assumed an overall duration of 37 days. It has been assumed that 7 days of this are common to all lengths and that the variance is based on the 30 days' duration. It may be possible to slightly reduce the number of locally hired equipment and labour for the shorter lengths but for the purposes of this estimate, it is felt unnecessary to do so. The labour and equipment costs will be adjusted in accordance with these criteria:

within the "local materials and misc. costs," there are approximately $70500 which are fixed and the remainder are variable with length. The fixed costs include travel, clothing allowance, office set-up, stores, etc.

since the equipment has not effectively changed for each of the spreads, the "mob/ /demob" cost will be fixed for each pipeline length.

the "camp/subsistence" costs have been altered in general accordance with the labour costs.

field monitoring was estimated under the same general conditions as the labour for construction. It has been assumed that the field inspection staff consists of an engineer, two inspectors, a surveyor and a radiographic technician.

6.5 Indirect Costs

Indirect costs consist of pre-permit costs, engineering and construction management and regulatory costs. On longer pipelines, these costs can be estimated by applying historically determined percentages to the construction costs, hut in this instance, we propose to allocate lump sum values to each of these items. in the absence of all the information, we have assumed these costs fixed for all pipeline lengths being considered.

Pre-permit cost	$ 20,000
Engineering cost	60,000
Construction mgmt.	40,000
Regulatory cost	30,000
TOTAL	$150,000

6.6 Operations and Maintenance Costs

Operations and maintenance costs are presented in Table 6.2 of this section.

An allowance of $50,000 has been given for a manager/inspector for the pipeline system. This position will not give full time employment for one person but in the absence of any knowledge of other details, we have allowed this sum to be included. Similarly, an allowance of $5000 has been included for a vehicle. An additional $25000 has been allocated for temporary labour and equipment. The office, warehouse and consumables cost has been estimated at $7500 per annum. This assumes the costs of the office and warehouse to be “written off” at a percentage per annum.

Since all labour is assumed to be local, there is no allowance for subsistence but $2500 has been included as a miscellaneous cost.

Fuel costs have been assumed at $0.65 /litre for the vehicle and equipment. This represents at an annual cost of $10000. Fuel requirements for the pipeline system (within our scope of work) will be limited to the requirements of the regulating and metering facility at the city gate. An allowance of $25000 has been included for this.

Additional costs for head office, accounting and clerical support are assumed as $15000 per annum.

TABLE 6.1
PIPEL NE COST SUMMARY

Diameter (mm	114.3	114.3	114.3	1 4.3	114.3	114.3
Length (km)	10	9	8	7	6	5
MATERIALS $000)						
Line pipe ($365.12/100 ft.)	138.35	24.52	10.68	96.85	83.01	69.18
Pipe coating ($62.70/100 ft.) + shrinksleeves + end caps	30.24	27.21	24.19	21.17	18.14	15.12
Miscellaneous 10% of above)	16.86	15.17	13.49	11.80	10.11	8.43
Material ransfer (3675∞ lbs. ≤ $15.25/1∞ lbs.)	56.04	50.44	44.83	39.23	33.63	28.02
	241.69	217.34	193.19	169.05	144.89	120.75
CONSTRUCTION ($0∞)						
Labour	426.51	391.93	357.35	322.77	288.19	253.61
Equipment	183.13	168.28	153.43	138.59	123.74	108.89
Local materials & misc. costs	100.50	97.50	94.50	91.50	88.50	85.50
Mob/demob	45.00	45.00	45.00	45.00	45.00	45.00
Camp/subsistence	138.38	127.85	117.32	106.79	96.26	85.73
	893.22	830.56	767.60	704.65	641.69	578.73
Fuel (8% of above cost)	71.[illegible]6	66.44	61.41	56.37	51.34	46.30
Contingency (10%	89.[illegible]2	89.70	82.90	76.10	69.30	62.50
	1054.[illegible]0	986.70	911.91	837.12	762.33	687.53
Contractor's O/M & Profit (15%)	158.[illegible]0	148.00	136.79	125.57	114.35	103.13
	1212.[illegible]0	1134.70	1048.70	962.69	876.68	790.66
ELO MON TORING ($000)						
Inspection	40.00	37.00	34.00	31.00	27.00	24.00
Field Engineering	19.40	17.95	16.49	15.04	13.58	12.12
Survey	24.40	22.57	20.74	18.91	17.08	15.25
Radiography	28.00	25.90	23.80	21.70	19.60	17.50
	111.80	103.42	95.03	86.65	77.26	68.87
METERING & REGULATING EQUIPMENT	125.∞	125.00	125.	12 ∞	25.00	125.00
TOTAL	1690.56	1580.46	1461.92	1343.39	1223.83	1105.28

150m. to be added ? Indic 6) (sec 6.5)

TABLE 6.2

OPERATIONS AND MAINTNENACE **COST**

Item	cost ($000)
Manager/ Inspector ($50000/year)	50.0
Temporary Labour & equipment	25.0
\,/chicle (annual write-off cost & maintenance)	5.0
Office, Warehouse & consumables	?.5
Miscellaneous	2.5
Vehicle fuel	10.0
Fuel for system operation	25.0
Support services (clerical, accounting & H.O.)	15.0
TOTAL O&M COST PER ANNUM	140.0

```
***********************************************
*                                             *
*          CANUCK ENGINEERING LTD.            *
*        200,200, Rivercrest Drive S.E.       *
*       Calgary, Alberta, Canada T2C 2X5      *
*       (403) 236-6000  Telex: 30-82678       *
*                                             *
*           Gas Properties Program            *
*                VERSION 4.0                  *
*                                             *
***********************************************
```

85-DEC-12 -GAP- VMA104

TUK GAS LINE

GAS THERMODYNAMIC PROPERTIES

GAS PROPERTIES AS PI? ED ICTED BY AN 11-CONSTANT
BkR EQUATION OF STATE

85-DEC-12 -GAP- VMA104

TUK GAS LINE

GAS COMPOSITION

METHANE	=	99.50%	N-HEPTANE	=	. 00%
ETHANE	=	, 50%	N-OCTANE	=	. 00%
PROPANE	=	.001	ETHYLENE	=	. 00%
N-BUTANE	=	, 00%	CARBON DIOXIDE	=	. 00%
I-BUTANE	=	. 00%	HYDROGEN SULFIDE	=	.001
N-PENTANE	=	.00%	HYDROGEN	=	. 00%
I-PENTANE	=	,001	NITROGEN	=	, 00%
N-HEXANE	=	.00%			

MIXTURE MOLECULAR MASS	= 16.1011
BASE TEMPERATURE	= 15.000 Deg c
BASE PRESSURE	= 101.325 kPa-abs
DENSITY AT BASE CONDITIONS	= .681 kg/m**3
NET HEATING VALUE	= :4.0683 MJ/m**3
GROSS HEATING VALUE	= 37. 3357 MJ /m**3

1000.0	2.2473	2.2433	2.2384	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2000.0	2.4039	2.3574	2.3434	2.3510	2.3739	2.4092	2.4545	2.5074
3000.0	2.6004	2.4911	2.4411	2.4257	2.4334	2.4579	2.4949	2.5416
4000.0	2.8528	2.6483	2.5505	2.5071	2.4966	2.5086	2.5367	2.5766
5000.0	3.1830	2.8341	2.6724	2.5949	2.5634	2.5615	2.5797	2.6124
6000.0	3.6172	3.0487	2.8067	2.6886	2.6334	2.6159	2.6236	2.6489
7000.0	4.1536	3.2930	2.9510	2.7872	2.7056	2.6717	2.6683	2.6854
8000.0	4.7449	3.5568	3.1051	2.8891	2.7794	2.7282	2.7132	2.7222
9000.0	5.2187	3.8194	3.2604	2.9924	2.8539	2.7849	2.7582	2.7587
10000.0	5 46 2	.0580	3.4109	3 94	2.9274	2.8413	2.8022	2.7947

THE JOULE-THOMSON COEFFICIENT (K/kPa)

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	.00	20.00	40.00	60.00	80.00	100.00
.0	.00710	.00605	.00521	.00451	.00393	.00343	.00303	.00267
1000.0	.00712	.00605	.00518	.00448	.00390	.00341	.00299	.00264
2000.0	.00712	.00602	.00512	.00444	.00385	.00336	.00294	.00259
3000.0	.00708	.00596	.00508	.00437	.00379	.00330	.00289	.00254
4000.0	.00699	.00587	.00500	.00429	.00372	.00324	.00283	.00249
5000.0	.00682	.00573	.00488	.00419	.00363	.00316	.00276	.00243
6000.0	.00652	.00553	.00473	.00408	.00353	.00308	.00269	.00236
7000.0	.00602	.00526	.00454	.00394	.00342	.00299	.00261	.00229
8000.0	.00534	.00492	.00433	.00378	.00330	.00288	.00233	.00222
9000.0	.00456	.00452	.00408	.00360	.00316	.00278	.00244	.00215
10000.0	.00379	.00407	.00380	.00341	.00302	.00266	.00235	.00207

THE ISENTROPIC TEMPERATURE CHANGE EXPONENT

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	.00	20.00	40.00	60.00	80.00	100.00
.0	.2458	.3396	.2370	.2327	.2279	.2226	.2171	.2115
1000.0	.2532	.2486	.2456	.2383	.2327	.2268	.2208	.2147
2000.0	.2598	.2541	.2484	.2427	.2365	.2302	.2237	.2173
3000.0	.2661	.2595	.2529	.2464	.2398	.2333	.2265	.2198
4000.0	.2713	.2640	.2569	.2499	.2429	.2359	.2291	.2220
5000.0	.2742	.2677	.2601	.2529	.2457	.2384	.2311	.2241
6000.0	.2737	.2689	.2623	.2552	.2479	.2405	.2331	.2260
7000.0	.2670	.2683	.2629	.2568	.2497	.2423	.2348	.1276
8000.0	.1547	.2649	.2630	.2575	.2508	.2436	.2562	.2287
9000.0	.2367	.2587	.2611	.2573	.2514	.2445	.2375	.2300
10000.0	.2180	.2506	.2578	.2562	.2514	.2453	.2380	.2307

THE SPECIFIC VOLUME (m**3/kg)

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	,00	20.00	40,00	60.00	80.00	100.00
.0	1.18330	1.29016	1.39209	1.49401	1,59594	1.69787	1.79980	1.90173
1000.0	,10427	.11449	,12454	.13441	.14431	,15407	.16378	.17345
2000.0	.05218	,05800	.06361	,06907	.07446	.07977	.08502	.09023
3000.0	.03360	.03791	.04197	.04589	,04970	.05341	,05708	.06071
4000.0	,02403	.02761	.03090	.03402	,03702	.03994	.04279	.04561
5000.0	.01818	.02134	,02418	,02683	.02954	.03177	.03414	.03645
6000.0	.01422	.01715	.01968	.02201	.02420	,02630	.02833	.03031
7000.0	.01140	.01415	.01648	.01857	.02053	.02239	.02418	.02592
8000.0	.00933	.01193	.01409	.01601	.01778	.01946	.02107	.02263
9000.0	.00783	.01025	.01226	,(11403	.01566	,01719	.01866	.02008
10000.0	.00676	.00895	.01082	.01247	.01398	.01539	.01674	,01804

ENTHALPY (kJ/kg)

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	,00	20.00	40.00	60.00	ao.00	100.00
0.	-3673.9	-3631.3	-3588.1	-5544.1	-3499.3	-3453.4	-3406.4	-5358.2
1000.	-3689.4	-3644.6	-3599.6	-1554,2	-:506.2	-3461,4	-3413.7	-3364.8
2000.	-3706.0	-3658.4	-3611.5	-3564.5	-3517.3	-3469.5	-3420.9	-3371.3
3000.	-1725.7	-3672.9	-3623.7	-1575.1	-3526.5	-3477.6	-3418.1	-3577a
4000.	-3742.9	-3688.1	-3636.3	-3585.7	-5535.8	-3485.7	-3435.3	-3384.2
5000.	-3763.7	-3704.0	-3649.1	-3596.b	-3545,1	-3493.a	-3442.5	-3390.4
6000.	-3786.3	-3720.6	-3662.3	-3607.5	-3554.4	-3501,9	-3449.6	-3396.9
7000.	-3810.6	-3737.7	-3675.7	-3618.5	-3563.b	-250'9.9	-3456.6	-3403.1
8000.	-3835.9	-3755.1	-3689.1	-3629.4	-3572,9	-3517.9	-3463.5	-3409.2
?000,	-3860.7	-3772.6	-3702.5	-3640.3	-3582.0	-3525.7	-3470.3	-3415.2
10000.	-3883.o	-3789.5	-3715.6	-3650.9	-3590.9	-3533.3	-3476.9	-3421.0

ENTROPY (kJ/(kg K))

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	.00	20.00	40,00	60.00	80.00	100,00
.0	11.054	11.227	11.389	11.544	11. 694	11.840	11. 982	12.120
1000.0	9.776	9.957	10.126	10.287	10.441	10.590	10.734	10. 874
2000.0	9. 394	9.505	9.762	9.928	10.086	10.238	10.385	10.527
3000.0	9.139	9.344	9.529	9.701	9.864	10.019	10.169	10,313
4000.0	8.935	9. 156	9.352	9.530	9.698	9.857	10.009	10.155
5000.0	8. 756	8.998	9.204	9.391	9. 563	9.726	9,881	10,029
6000.0	8.590	8.857	9.076	9.270	9.448	9.615	9.773	9.923
7000.0	8.431	8.728	8.962	9.164	.9.:48	9.518	9.679	9.831
0000.0	8.278	8.607	8.857	9, 068	9,257	9.432	9.595	9.750
9000. 0	8.135	8.495	8.760	8.980	9. 175	9.353	9.520	9.677
10000.0	8.008	9.390	8.669	8.898	9,099	9.281	9.451	9.610

ELEVATION SENSITIVITY COEFFICIENT (K/kPa)

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	.00	20.00	40.00	60.00	80.00	100.00
.0	,57707	.78574	, 64365	. 66804	.68889	.7082a	, 72906	.75209
1000.0	, 05486	,05811	. 06073	. 06286	, 06467	. 06638	.06819	.07024
2000.0	.02947	.03112	,03245	. 03355	,03447	.03532	. 03623	,03727
3000.0	,02042	.02150	, 02238	,02309	.02369	.02427	.02487	,02555
4000.0	.01571	.01653	.01719	.01772	.01816	.01857	.01902	.01953
5000.0	.01274	.01346	.01399	,01442	.01477	,01510	.01544	.01585
6'000.0	.01061	.01130	.01179	.01217	,01247	.01274	.01303	.01337
7000.0	. 00888	, 00967	.01016	.01052	.01080	,01104	,01129	.01157
8000.0	.00741	,00837	.00890	,00925	.00951	,90973	,00996	.01021
9000.0	.00613	.00727	,00786	.00823	,00849	,00870	.00891	.00914
10000.0	.00500	,00$ 34	. 00699	.00739	.00765	, 00787	,00005	.00826

VISCOSITY (mm**2/s)

PRESSURE (kPa-gauge)	TEMPERATURE (degree C)							
	-40.00	-20.00	,00	20.00	40.00	60.00	80.00	100.00
.0	10. 6817	12.5725	14.5384	16.6192	18.8107	21. 1090	23.5105	26.0119
1000.0	.9512	1,1262	1.3117	1.5073	1.7128	1.9279	2.1522	2. 3856
2000.0	.4045	.5792	, 6789	, 7834	.B931	1.0077	1.1270	1.2510
3000.0	.3197	,3862	. 4556	.5282	. 6039	,6827	. 7b47	.0498
4000.0	. 2360	.2883	.3423	.5984	.4548	.5174	.5802	. 6454
5000.0	,1859	.2296	.2743	.5204	. 3682	.4177	, 4b90	.5220
6000.0	.1531	.1911	.7274	, 2688	.3094	.3515	.1949	.4397
7000.0	.1308	,1643	.1980	,2324	. 2679	,:045	.5423	.3812
8000.0	,1158	.1452	.1751	,2057	.2372	, 2697	.3031	. 3376
9000.0	,1062	.1314	.1580	,1855	.2138	,2430	.2731	.3041
10000.0	. 100A	.1215	.1451	.1699	. 1956	,?221	,2494	.2776

LOW PRESSURE HYDRAULIC OUTPUT

1,

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

i

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	689. 50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERAT ING PRESSURE	=	5102.30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-10.00 Deg C	DEFAULT COMPRESSOR D ISCHARGE PRESSURE	=	5102.30 kPa-g
MAX IMUM OPERATING TEMPERATURE	=	40.00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg c
ADIABATIC COMPRESSION EFFICIENCY	=	80.00 %	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40,00 Deg C
COOLER EFFICIENCY	=	80.00 %	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION ! km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (5/5)	AVERAGE D ENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deq C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	85019.	8.0591	9.665	722193.	,004050	35.00	1500.00	
SEGMENT	1.000	100.00	85019.	7.7053	10. 086	765213.	. 004050	6.83	1451.55	
SEGMENT	2.000	50.00	85019.	7.7313	10. 066	780508.	.004050	-2. 37	1410.17	
SEGMENT	3.000	100.00	85019.	7.8789	9.877	786713.	.004050	-6.03	1358.75	
SEGMENT	4.000	75.00	85019.	8.0605	9.643	789167.	.004050	-7.01	1313. 80	
SEGMENT	5.000	50.00	85019.	8.2764	9.392	789913.	.004050	-7.18	1267.71	
SEGMENT	6. 000	50.00	85019.	8.5061	9,140	790476.	, 004050	-7.33	1217.95	
SEGMENT	7.000	50.00	85019.	8.7435	8.892	790938.	.004050	-7.41	1166.81	
SEGMENT	8.000	50.00	85019.	8.9882	8.650	791345.	.004050	-7.45	1114,24	
SEGMENT	9. 000	50. 00	85019.	9.2400	8.415	791720.	,004050	-7.4a	1060.20	
ENDPOINT	10.000	50.00						-7.49	1004. 65	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VHA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	8.3570	9.304
2	SEGMENT	1.000	7,7547	10.027
3	SEGMENT	2.000	7.6646	10.145
4	SEGMENT	3.000	7.7859	9.987
5	SEGMENT	4.000	7.9612	9. 767
6	SEGMENT	5.000	8.1682	9.519
7	SEGMENT	b. 000	8.3925	9.265
8	SEGMENT	7.000	8.6254	9.014
9	SEGMENT	8.000	8.8662	0.770
10	SEGMENT	?.000	9.1143	8.531
11	END POINT	10.000	9.3696	8.298

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
,000	100.00	.762	114.300	4.7750	.04570	. ?500	-7.20	1.2000	,00	,00000
1.000	100.00	.762	114.300	4.7750	,04570	.9500	-7.20	1. 2000	.00	,00000
2.000	50.00	.762	114.300	4.7750	.04570	,9500	-7,20	1.2000	.00	i 00000
3.000	100coo	.762	114.300	4.7750	.04570	.9500	-7.20	1.2000	.00	.00000
4.000	75.00	.762	114.300	4, 77s0	.04570	,9500	-7 , 20	1. 2000	.00	.00000
5. 000	50.00	.762	114.300	4.7750	, 04570	.9500	-7.20	1.2000	.00	.00000
6.000	50.00	.762	114.300	4,7750	.04570	.9500	-7.20	1.2000	.00	.00000
7.000	50.00	.762	114.300	4,7750	,045?0	.9500	-7.20	1,2000	.00	.00000
a. 000	50.00	.762	114.300	4, 7750	,04570	.9500	-7. 20	1.2000	.00	,00000
9.000	50,00	.762	114.300	4.7750	.04570	.9500	-7.20	1.2000	.00	,00000
10,000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	689. 50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PRESSURE	=	5102. 30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-10.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	5102.30 kPa-g
MAXIMUM OPERATING TEMPERATURE	=	40,00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40. 00 Deg C
AD IABATIC COMPRESSI ON EFFICIENCY	=	80.001	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
COOLER EFFICIENCY	=	80.00 %	HEATER EFFICIENCY	=	00.001

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	,000	100.00	99189.	7.9366	11.450	840086.	.004050	35.00	1750.00	
SEGMENT	1.000	100.00	99189.	7.6551	11.845	890129.	.004050	6.81	1694.33	
SEGMENT	2.000	50.00	99189.	7.7556	11.708	908094 ,	,004050	-2. 40	1646.45	
SEGMENT	3.000	100.00	99189.	7.9842	11. 372	915556.	,004050	-b. 07	1586.31	
SEGMENT	4.000	75.00	99189.	8.2451	10.998	918641.	.004050	-7.05	1533.09	
SEGMENT	5.000	50.00	99189.	8.5491	10. 608	919749,	,004050	-7,22	1477.96	
SEGMENT	b. 000	50.00	99189.	8.8745	10.220	920638.	.004050	-7.38	1417.99	
SEGMENT	7.000	50.00	99189.	9.2136	9.845	921400,	, (104050	-7.46	1355.74	
SEGMENT	8.000	50. 00	99189.	9.5663	9,482	922086.	,004050	-?.51	1291.12	
SEGMENT	q, 000	50.00	99189.	9.9328	9.133	922727,	,004050	-7.54	1224.02	
ENDPOINT	10.000	50.00						-7.57	1154. 34	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	8.1911	11.075
2	SEGMENT	1.000	7.6709	11.826
3	SEGMENT	2.000	7.6464	11.864
4	SEGMENT	3.000	7.8520	11.553
5	SEGMENT	4.000	8.1054	11.192
6	SEGMENT	5.000	8.3960	10.804
7	SEGMENT	6.000	8.7130	10.41[illegible]
8	SEGMENT	7.000	9.0446	10.029
9	SEGMENT	8.000	9.3902	9.660
10	SEGMENT	9.000	9.7497	[illegible].304
11	END POINT	10.000	10,1232	8.96[illegible]

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION conductivity (W/(m Deg C))
.000	100.00	.762	114.300	4.7750	, 04570	,9500	-7.20	1.2000	.00	. 00000
1.000	100.00	.762	114.300	4,775(I	.04570	.9500	-7.20	1.2000	.00	.00000
2.000	50.00	.762	114.304	4.7750	.04570	. 9500	-7.20	1.2000	.00	, 00000
3.000	100. 00	.762	114,300	4.7750	.94:70	.9500	-7.20	1.2000	.00	,00000
4.000	75.00	.762	114.300	4,7750	,04570	,9500	-7.20	1.2000	.00	, 00000
5.000	50.00	.762	114.300	4.7750	,04370	. 9500	-7.20	1.2000	.00	.00000
6.000	50.00	.762	114.300	4.7750	.04570	,9500	-7.20	1.2000	,00	,00000
7.000	50. 00	.762	114.300	4.7750	,04570	, ?500	-7.20	1.2000	.00	,00000
8.000	50.00	.762	114.300	4.7750	.04570	,9500	-7.20	1.2000	,00	,00000
9.000	50.00	.762	114.300	4,7750	.04570	. 9500	-7.20	1.2000	.00	.00000
10.000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	689. 50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PRESSURE	=	5102.30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-10.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	5102,30 kPa-g
MAXIMUM OPERATING TEMPERATURE	=	40.00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COHPRESS1ON EFFICIENCY	=	80.00 %	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
COOLER EFFICIENCY	=	90,00 %	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	127527.	8.3904	13.943	1073341.	,004050	35.00	2000.00	
SEGMENT	1.000	100.00	127527,	8.2859	14.076	1137954.	.004050	7.43	1924.33	
SEGMENT	2.000	50.00	127527.	8.5938	13.592	1162014.	.004050	-2.02	1836.51	
SEGMENT	3.000	100.00	127527.	9. 0644	12.886	1173755,	,004050	-5.92	1772.35	
SEGMENT	4.000	75.00	127527.	9.5779	12.171	1178996.	,004050	-7,08	1693.77	
SEGMENT	5.000	50.00	127527.	10.1741	11.460	1181283.	,004050	-7.33	1610.38	
SEGMENT	b. 000	50.00	127527.	10.8222	10.775	1183188.	.004050	-7.53	1518.62	
SEGMENT	7.000	50.00	127527.	11.5254	10.129	1184786.	,004050	-7.65	1421.03	
SEGHENT	8.000	50.00	127527.	12.2621	9.520	1186382.	.004050	-7.74	1317,09	
SEGMENT	'?.000	50.00	127527.	13.0475	8.947	1187776.	,004050	-7. 80	1206,50	
ENDPOINT	10,000	50.00						-7.84	1088.84	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (s/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	,000	8.5272	13. 677
2	SEGMENT	1.000	a. 2080	14.209
3	SEGMENT	2.000	8.3650	13.942
4	SEGMENT	3.000	8.8080	13.241
5	SEGMENT	4.000	9.3073	12.53:
6	SEGMENT	5.000	9.8741	11.812
7	SEGMENT	6.000	10.4996	11.108
8	SEGMENT	7.000	11.1685	10.443
9	SEGMENT	0.000	11.8818	9.816
10	SEGMENT	9.000	12. 6427	9.225
11	END POINT	10.000	13.4329	8. 669

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	100.00	.742	114.300	4.7750	.04570	.9500	-7.20	1.2000	,00	,00000
1.000	100.00	.762	114.300	4.7750	.04570	.9500	-7.20	1.2000	.00	.00000
2.000	50.00	,762	114.300	4.7750	,04570	.9500	-7.20	1.2000	,00	.00000
3.000	100.00	,762	114,300	4.7750	.04570	.9500	-7.20	1.2000	.00	.00000
4.000	75.00	,742	114.300	4.7750	,04570	.9500	-7.20	1.2000	.00	.00000
5.000	50.00	,762	114.300	4.7750	,04570	.9500	-7.20	1.2000	.00	.00000
6.000	50.00	.762	114.300	4.7750	.04570	,9500	-7.20	1.2000	,00	.00000
7.000	50.00	.762	114.300	4.7750	.04570	.9500	-7.20	1.2000	.00	.00000
8.000	50.00	.762	114.300	4.7750	,04570	.9500	-7.20	1.2000	,00	.00000
9.000	50.00	,762	114.300	4.7750	.04570	,9500	-7.20	1.2000	.00	.00000
10.000	50.00									

GAS PI FELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE =	689.50 kPa-g		COMPRESSOR INLET LOSS =	50.00 kPa
MAXIMUM OPERATING PRESSURE =	5102.30 kPa-g		C OPPRESSOR OUTLET LOSS =	50.00 kPa
MINIMUM OPERATING TEMPERATURE =	-5.00 Deg C		DEFAULT COMPRESSOR DISCHARGE PRESSURE =	5102.30 kPa-g
MAXIMUM OPERATING TEMPERATURE =	40.00 Deg C		DEFAULT COOLER OUTLET TEMPERATURE =	40.00 Deg c
ADIABATIC COMPRESSION EFFICIENCY =	80.00 %		DEFAULT LINE HEATER DISCHARGE TEMPERATURE =	40.00 Deg C
COOLER EFFICIENCY =	80,001		HEATER EFFICIENCY =	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEHP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	127527.	8.4679	13.804	1065887.	.004050	35.00	2000.00	
SEGMENT	1.000	100,00	127527.	8.4900	13.738	1117963.	.004050	12.11	1723.63	
SEGMENT	2.000	50.00	127527.	8.8571	13.168	1139846.	.004050	4.28	1853.81	
SEGMENT	5.000	100.00	127527.	9.3937	12.434	1147075.	,004050	1.23	1767. 47	
SEGMENT	4.000	75.00	127527.	9.9464	11.721	1153000.	,004050	.11	1685.80	
SEGMENT	5.000	50.00	127527.	10.5843	11. 016	1155113.	.004050	-.13	1598.98	
SEGMENT	6. 000	50.00	127527.	11.2907	10.341	1156770.	.004050	-.32	1503.53	
SEGMENT	7.000	50.00	127527.	12.0?08	?. 704	1158487,	.004050	-.48	1401.71	
SEGMENT	8.000	50.00	127527.	12.8226	9.105	1159902.	.004050	-.55	1293.21	
SEGMENT	9.000	50.00	127527.	13. 6673	8.542	1161188.	,004050	-,59	1177.57	
ENDPOINT	10.000	50.00						-.63	1054.32	

-

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VHA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	,000	0.5272	13.677
2	SEGMENT	1.000	8.3716	13.932
3	SEGMENT	2.000	8.6106	13.545
4	SEGMENT	3.000	9.1182	12.791
5	SEGMENT	4.000	9.6563	12.078
6	SEGMENT	5.000	10.2634	11.364
7	SEGMENT	6.000	10.9324	10.668
8	SEGMENT	7.000	11.6477	10.013
9	SEGMENT	8.000	12.4140	9.3?5
10	SEGMENT	9,000	13.2318	8.814
11	END POINT	10.000	14.1035	8.269

HIGH PRESSURE HYDRAULIC OUTPUT

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	,	68?, 50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAX IMUM OPERATING PRESSURE	=	9930.30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-5,00 Deg C	DEFAULT COMPRESSOR DISCHARGE PEESSURE	=	9930,30 kPa-g
MAXIMUM OPERATING TEMPERATURE	=	40.00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY	=	80. 00 %	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40,00 Deg c
COOLER EFFICIENCY	=	80.00 z	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEHP (Deg C)	INLET PRESSURE {kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	595133,	6.6621	81.637	4235118.	.004050	15,00	9930.00	
SEGMENT	1.000	100,00	595133.	6. 7554	80.521	4284366.	,004050	11.98	9649.62	
SEGMENT	2.000	50.00	595133.	6. 8706	79.174	4337924.	.004050	9.61	9404,83	
SEGMENT	3.000	100.00	595133.	7.0189	77.417	4395151.	, 004050	4.97	9076. 82	
SEGMENT	4.000	75.00	595133.	7.2158	75.399	4452479,	,004050	5.06	8800. 44	
SEGMENT	5.000	50.00	59513s.	7.4328	73. 202	4511945,	.004050	3.35	8515.26	
SEGMENT	6. 000	50.00	595133.	7.6698	70.781	45732?0.	,004050	1.67	8202,44	
SEGMENT	7.000	50.00	595133.	8.0038	67.988	4639119,	.004050	.15	7879. 65	
SEGMENT	8. 000	50.00	595133.	8.3680	65.029	4702308.	.004050	-1.25	7542. 81	
SEGMENT	9.000	50.00	595133,	8.7540	61.900	4765581 .	, 004050	-2.54	7190.63	
ENDPO INT	10.000	50.00						-3.75	6822. 22	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	6.6202	82.214
2	SEGMENT	1.000	6.7145	81.060
3	SEGMENT	2.000	6.8050	79.982
4	SEGMENT	3.000	6.9452	78.367
5	SEGMENT	4.000	7.1178	76.466
6	SEGMENT	5.000	7.3222	74.332
7	SEGMENT	6.000	7.5519	72.071
8	SEGMENT	7.000	7.8323	69.491
9	SEGMENT	8.000	8.1865	66.485
10	SEGMENT	9.000	8.5615	63.573
11	END POINT	10.000	9.0371	60.227

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
,000	100,00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	,00	.00000
1.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	,00	.00000
2.000	50.00	.762	114.300	4.7750	.04570	.9500	,00	1.2000	.00	.00000
3.600	100.00	.762	114.300	4,7750	.04570	.9500	.00	1.2000	,00	.00000
4.000	75.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	,00000
5.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	,00	.00000
6.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	,00	.00000
7.000	50.00	.762	114.300	4,7750	.04570	.9500	.00	1.2000	.00	,00000
8.000	50,00	.762	114.300	4.7750	,04570	.9500	,00	1.2000	,00	.00000
9,000	50.00	.762	114.300	4.7750	.04570	.9500	,00	1.2000	.00	.00000
10,000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE = 689.50 kPa-g
MAXIMUM OPERATING PRESSURE = 9930.30 kPa-g
MINIMUM OPERATING TEMPERATURE = -5.00 Deg C
MAXIMUM OPERATING TEMPERATURE = 40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY = 80.00 %
COOLER EFFICIENCY = 80.00 %

COMPRESSOR INLET LOSS = 50.00 kPa
COMPRESSOR OUTLET LOSS = 50.00 kPa
DEFAULT COMPRESSOR DISCHARGE PRESSURE = 9930.30 kPa-g
DEFAULT COOLER OUTLET TEMPERATURE = 40.00 Deg C
DEFAULT LINE HEATER DISCHARGE TEMPERATURE = 40,00 Deg C
HEATER EFFICIENCY = 80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	510114.	5.6819	82.030	3625571.	.004050	15.00	9930,00	
SEGMENT	1.000	100.00	510114.	5.7083	81.668	3657981 .	.004050	11.93	9725.04	
SEGMENT	2.000	50.00	510114.	5.7558	80.994	3693579.	.004050	9,61	9559. ?0	
SEGMENT	3.000	100.00	510114.	5.8225	80.082	3730549.	,004050	7.08	931! .82	
SEGMENT	4.000	75.00	510114.	5.8885	79. 103	3762537.	. 004050	5.35	9121.43	
SEGMENT	5.000	50.00	510114.	6.0008	77.712	3799601.	,004050	3.87	8928.44	
SEGMENT	6.000	50.00	510114.	6.1340	76.029	3838618.	.004050	2.45	8711.97	
SEGMENT	7.000	50.00	510114.	b. 2770	74.301	3877108,	. 004050	1.22	8490.70	
SEGMENT	8,000	50.00	510114.	6.4274	72. 568	3913578.	.004050	.15	8264. 26	
SEGMENT	9.000	50. 00	510114.	6.6055	70. 566	3949384.	.004050	-.78	8032.40	
ENDPOINT	10. 000	50.00						-1.61	7794. 12	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -G AP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	5.6745	82.214
2	SEGMENT	1.000	5.7001	81.845
3	SEGMENT	2.000	5.7248	.91,491
4	SEGMENT	3.000	5.7955	80.498
5	SEGMENT	4.000	5.8559	79.667
6	SEGMENT	5.000	5.9400	78.539
7	SEGMENT	6.000	6.0678	76.885
8	SEGMENT	7.000	6.2059	75.174
9	SEGMENT	8.000	6.3535	73.4?.7
10	SEGMENT	9.000	6.5058	71.708
11	END POINT	10,000	6.7199	69.424

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	100.00	.762	114.300	4.7750	,04570	,9500	,00	1.2000	,00	,00000
1.000	100.00	.762	114.300	4.7730	.04570	.7500	.00	1.2000	.00	.00000
2.000	50.00	.762	114.300	4.7750	,04570	.9500	.00	1. 2000	,00	,00000
3.000	100.00	.762	114.300	4.7750	,04570	,9500	.00	1.2000	.00	.00000
4.000	75.00	.762	114.300	4,7750	.04570	.9500	,00	1.2000	.00	,00000
5.000	50,00	.762	114,300	4,7750	.04570	,9500	.00	1. 2000	.00	.00000
6.000	50.00	.762	114.300	4.7750	,04570	. 9500	.00	1.2000	,00	.00000
7.000	50,00	.762	114.300	4, 7750	,04570	. 9500	.00	1.2000	.00	.00000
8.000	50.00	.762	114.300	4.7750	,04570	.9500	.00	1.2000	,00	, 0 0 0 0 0
?, 000	50.00	.762	114.300	4.7750	, 04570	.9500	.00	1.2000	, 00	.00000
10.000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE =	689,50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 k?a
MAXIMUM OPERATING PRESSURE =	9930,30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE =	-5.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	9930,30 kPa-g
MAXIMUM OPERATING TEMPERATURE =	40.00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY =	B0.00 Z	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
COOLER EFFICIENCY =	80.00 %	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	510114.	7. 0?54	66.339	3826768.	, 004050	15.00	8275. 00	
SEGMENT	1.000	100.00	510114,	7.1285	65.365	3873335 .	.004050	11.55	0021.57	
SEGMENT	2.000	50.00	510114,	7.3030	63. 836	3925298.	,004050	8.90	7796.52	
SEGMENT	3.000	100.00	510114.	7.5068	62.111	3977341.	,004050	6.12	7501. 74	
SEGMENT	4.000	75.00	510114.	?.7130	60.431	4023639.	.004059	4.14	7246. 18	
SEGMENT	5.000	50.00	510114,	B. 0025	50.275	4074145.	,004050	2.45	6982.78	
SEGMENT	6. 000	50.00	510114.	8.3696	55.731	4127793.	.004050	.04	6694.11	
SEGMENT	7.000	50,00	510114.	8.7556	53.268	4175635.	.004050	-.57	4392.18	
SEGMENT	8.000	50.00	510114.	9.2176	50.478	4224666.	.004050	-1.83	6076. 34	
SEGMENT	9.000	50.00	510114.	9.0773	47.288	4279840.	.004050	-2.96	5743.83	
ENDPOINT	10.000	50.00						-4.02	5387.52	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	6.9951	66.693
2	SEGMENT	1.000	7.0702	45.984
3	SEGMENT	2.000	7.2053	44.747
4	SEGMENT	3.000	7,4140	62.925
5	SEGMENT	4,000	7.6107	61.298
6	SEGMENT	5.000	7.8322	5?.564
7	SEGMENT	6.000	8.1868	56.985
8	SEGMENT	7.000	8.5635	54.478
9	SEGMENT	8.000	8.9617	52.057
10	SEGMENT	9.000	9.5405	48.899
11	END POINT	10,000	10.2134	45.678

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- YMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
1.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
2.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
3.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
4.000	75.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
5.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
6.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
7.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
8.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
9.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
10.000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE =	689.50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PRESSURE =	9930.30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE =	-5.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	9930. 30 kPa-g
MAXIMUM OPERATING TEMPERATURE =	40.00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY =	90.001	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40.00 Deg C
COOLER EFFICIENCY =	80.001	HEATER EFFICIENCY	=	90.002

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C!	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	.000	100.00	340076.	4.6385	67.077	2546372.	, 004050	15.00	6275.00	
SEGMENT	1.000	100.00	340076.	4.5863	67.721	2568317.	,004050	10. 92	8163.45	
SEGMENT	2. 000	50.00	340076.	4.5723	67.859	2588286.	.004050	8.18	8086.42	
SEGMENT	3.000	100.00	340076.	4.5991	67.570	2608454 ,	,004050	5.58	7?43.0?	
SEGMENT	4.000	75.00	340076.	4.6283	67.156	2625905.	.004050	3.98	7849. 07	
SEGMENT	5.000	50.00	340076.	4.6712	66.545	2639359.	,004050	2.75	7754. 25	
SEGMENT	6.000	50.00	340076.	4.7268	65.771	2654633.	.004050	1.68	7641. 91	
SEGMENT	7.000	50.00	340076.	4.7895	64.916	2668887.	,004050	.85	7520.23	
SEGMENT	8.000	50.00	340076.	4.8578	64.012	2682090.	. 004050	,?1	7413.05	
SEGMENT	9,000	50.00	340076.	4.9296	63.078	2693716.	.004050	-.29	7296.23	
ENDPOINT	10. 000	50.00						-.6!	7177. 67	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	,000	4.6634	66. 693
2	SEGMENT	1.000	4.6103	67.460
3	SEGMENT	2.000	4.5750	67.981
4	SEGMENT	3.000	4.5914	67. 738
5	SEGMENT	4.000	4.6143	67.402
6	SEGMENT	5.000	4.6483	66.909
7	SEGMENT	6,000	4.6994	66.182
8	SEGMENT	?, 0(J0	4.7585	65. 360
9	SEGMENT	8.000	4.8240	64.472
10	SEGMENT	9.000	4.8939	63.551
11	END POINT	10.000	4.9680	62. 604

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA.104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	100.00	.762	114.300	4.7750	,04570	.9500	,00	1.2000	,00	,00000
1.000	100.00	.742	114.300	4.7750	.04570	.9500	,00	1.2000	.00	,00000
2.000	50.00	.762	114,300	4.7750	.04570	,0500	,00	1.2000	,00	,00000
3,000	100.00	.762	114.300	4.7750	.04570	.?500	,00	1.2000	.00	.00000
4.000	75.00	.762	114.300	4.7754	,04570	.9500	.00	1.2000	.00	.00000
5.000	50.00	.762	114.300	4.7750	.04570	.9500	,00	1,2000	.00	,00000
6.000	50.00	.762	114.300	4.7750	,04570	,9500	,00	1.2000	,00	,00000
7.000	50.00	.762	114.300	4.7750	,04570	.9500	,00	1.2000	,00	.00000
8.000	50.00	.762	114.300	4,7750	.04570	.9500	,00	1.2000	,00	.00000
9.000	50.00	.762	114.300	4.7750	,04570	.?500	.00	1,2000	,00	.00000
10.000	50.00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-12 -6 AP- VMA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	689.30 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PRESSURE	=	9930.30 kPa-g	COMPRESSOR OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-5.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	9930,30 kPa-g
MAXIMUM OPERATING TEMPERATURE	=	40,00 Deg C	DEFAULT COOLER OUTLET TEMPERATURE	=	40.00 Deg C
ADIABATIC COMPRESSION EFFICIENCY	=	80.00 %	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40,00 Deg C
COOLER EFFICIENCY	=	80.001	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	,000	100.00	170038.	2.2862	68.000	1274321.	.004050	15.00	8275,00	
SEGMENT	1,000	100.00	170038.	2.2192	70.163	1284376.	,004050	8.43	8247.51	
SEGMENT	2.000	50.00	170038.	2. 1822	71.320	1292137.	,004050	4.88	8235.19	
SEGMENT	3.000	100.00	170038.	2.1632	71,805	1298139.	.004050	2.43	8194,00	
SEGMENT	4.000	75.00	170030.	2.1557	72.088	1300076,	.004050	1.50	8185.62	
SEGMENT	5.000	50,00	170038,	2. 1534	72.173	1301974,	,004050	.95	8177.39	
SEGMENT	6. 000	50.00	170038s	2.1559	72.105	1303905.	,004050	.49	8151.50	
SEGMENT	7.000	50.00	170038.	2.1603	71. 967	1305530.	,004050	.22	8125.57	
SEGMENT	8.000	50.00	170038.	2. 1659	71.789	1306940.	.004050	.05	8099. 60	
SEGMENT	9.000	50.00	170038.	2.1721	71.587	1308156,	,004050	-,05	8073.55	
ENDPOINT	10.000	50.00						-.11	8047.43	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	,000	2.3317	66.693
2	SEGMENT	1,000	2.2438	69.306
3	SEGMENT	2.000	2.1896	71.020
4	SEGMENT	3.000	2.1713	71. 620
5	SEGMENT	4.000	2,1601	71. 990
6	SEGMENT	5.000	2.1543	72.186
7	SEGMENT	6.000	2.1550	72. 16[illegible]
8	SEGMENT	7.000	2.1583	72.050
9	SEGMENT	8.000	2.1633	71.885
10	SEGMENT	9.000	2. 1691	71. 693
11	END POINT	10.000	2.1735	71.482

5AS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (m)	DEPTH OF COYER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (5s)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
,000	100.00	.762	114.300	4.7750	, 04570	.9500	.00	1.2000	.00	,00000
1.000	100.00	, 762	114.300	4.7750	.04570	, 9500	,00	1.2000	.00	,00000
2.000	50.00	. 762	114.300	4.7750	.04570	.9500	, 00	! .2000	.00	,00000
3.000	100.00	. 762	114.300	4, 775(J	,04570	.9500	.00	1.2000	.00	.00000
4.000	75. 00	. 762	114.300	4. 7750	, 045?0	,9500	, 00	1. 2000	.00	.00000
5.000	50.00	, 762	114.300	4.7750	, 04570	.9500	.00	1.2000	,00	.00000
6.000	50.00	. 762	114.300	4.7750	. 045?0	.9500	.00	1.2000	.00	.00000
7,000	50.00	. 762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
8.000	50.00	. 7b2	114.300	4.7750	, 04570	.9500	, 00	1. 2000	,00	, 00000
9.000	50.00	. 762	114.300	4,7750	.04570	.9500	. 00	1. 2000	,00	, 00000
10.000	50,00									

GAS PIPELINE HYDRAULIC DESIGN SUMMARY

85-DEC-1 2 -GAP- VNA. 104

TUK GAS LINE

MINIMUM OPERATING PRESSURE	=	689. 50 kPa-g	COMPRESSOR INLET LOSS	=	50.00 kPa
MAXIMUM OPERATING PEESSURE	=	9930.30 kPa-g	Compressor OUTLET LOSS	=	50.00 kPa
MINIMUM OPERATING TEMPERATURE	=	-5.00 Deg C	DEFAULT COMPRESSOR DISCHARGE PRESSURE	=	9930,30 kPa-g
MAX IMUM OPERATING TEMPERATURE	=	40.00 Deg c	DEFAULT COOLER OUTLET TEMPERATURE	=	40,00 Deg C
ADIABATIC COMPRESSION EFFICIENCY	=	80. 00 %	DEFAULT LINE HEATER DISCHARGE TEMPERATURE	=	40,00 Deg c
COOLER EFFICIENCY	=	80.00 %	HEATER EFFICIENCY	=	80.00 %

FACILITY TYPE	INLET LOCATION (km)	INLET ELEVATION (m)	INLET FLOW (m**3/d)	AVERAGE VELOCITY (m/s)	AVERAGE DENSITY (kg/m**3)	REYNOLDS NUMBER	FRICTION FACTOR	INLET TEMP (Deg C)	INLET PRESSURE (kPa-gauge)	POWER (kW)
SEGMENT	,000	100.00	85019.	1.1286	68.857	638708.	,004050	15,00	8275,00	
SEGMENT	1.000	100.00	85019.	1.0816	71. 973	644990.	.004050	5.14	8268.21	
SEGMENT	2.000	50.00	85019.	1.0654	73.118	647800.	.004050	1.80	8296.97	
SEGMENT	3.000	100.00	85019.	1.0606	73.387	649509.	,004050	,20	8254.77	
SEGMENT	4,000	75,00	85019.	1.0584	73.519	649330.	.004050	.13	8266. 37	
SEGMENT	5.000	50.00	85019.	1.0568	73.586	649068.	.004050	.13	8278.03	
SEGMENT	6.000	50,00	85019.	1.0565	73.563	647374.	,004050	-.03	8271. 67	
SEGMENT	7.000	50.00	85019,	1.0574	73.500	649518.	, 004050	-,03	8265.32	
SEGMENT	8.000	50.00	85019,	1.0583	73,437	649661.	.004050	-.03	8258. 96	
SEGMENT	9.000	50.00	85019.	1,0592	73. 374	649804.	,004050	-.03	8252. 60	
ENDPOINT	10.000	50.00						-.03	8246.21	

GAS PIPELINE FLOW CHARACTERISTICS SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

FACILITY NUMBER	FACILITY TYPE	INLET LOCATION (km)	INLET VELOCITY (m/s)	INLET DENSITY (kg/m**3)
1	SEGMENT	.000	1.1658	66.693
2	SEGMENT	1.000	1,0948	71.022
3	SEGMENT	2.000	1.0662	72.924
4	SEGMENT	3.000	1. 0606	73.312
5	SEGMENT	4.000	1.0584	73.462
6	SEGMENT	5.000	1. 0568	73.577
7	SEGMENT	6.000	1. 0565	73.595
8	SEGMENT	7.000	1.0574	73.532
9	SEGMENT	a, 000	1.0503	73.469
10	SEGMENT	9.000	1.0592	73.406
11	END POINT	10.000	1.0601	73.343

GAS PIPELINE PROFILE SUMMARY

85-DEC-12 -GAP- VMA. 104

TUK GAS LINE

LOCATION (km)	ELEVATION (*)	DEPTH OF COVER (m)	OUTER DIAMETER (mm)	WALL THICKNESS (mm)	PIPE ROUGHNESS (mm)	DRAG FACTOR	GROUND TEMPERATURE (Deg C)	GROUND CONDUCTIVITY (W/(m Deg C))	INSULATION THICKNESS (mm)	INSULATION CONDUCTIVITY (W/(m Deg C))
.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
1.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.100	.00000
2.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
3.000	100.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
4.000	75.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
5.000	50.00	.762	114.300	4.7350	.04570	.9500	.00	1.2000	.00	.00000
6.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
7.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
8.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
9.000	50.00	.762	114.300	4.7750	.04570	.9500	.00	1.2000	.00	.00000
10.000	50.00									

APPENDIX 7.

Preliminary Market Study for a Natural Gas Project in Tuktoyaktuk, Bogach Associates Ltd. January, 1986.

PRELIMINARY MARKET STUDY FOR

A NATURAL GAS PROJECT IN TUKTOYAKTUK

V. SUSAN BOGACH

January, 1986

INDEX

1. INTRODUCTION

This report contains the results of a survey done in order to establish the potential demand for natural gas in Tuktoyaktuk and the nearby bases of oil and transportation companies. For each major user, current annual fuel use for heating and power generation was established, the degree of variability of use on a seasonal basis was investigated, a forecast of use was made, the price at which gas could replace alternative fuels was estimated, and a forecast was made of fuel prices in Tuk. Approximate estimates of gas demand in Inuvik were added as one of the options considered in section 5, but those estimates are more approximate than those for Tuk where most of the study was concentrated.

2. CURRENT CONSUMPTION OF DIESEL AND HEATING OIL IN TUK

2.1 THE COMMUNITY OF TUKTOYAKTUK

Gas could be used by individual households and businesses as a heating fuel, instead of P-50. Consumers of heating fuel in the community can be divided into four groups: the housing association, private households, private commercial and industrial users and government agencies. Data on heating fuel use by these consumers is given in Tables 1 and 2.

HOUSING ASSOCIATION

The housing association in Tuk accounted for 30 per cent of the heating fuel use in 1984/85, with 137 units at an average consumption of 4,000 liters per unit (see table 1). By end 1985, the housing association will have 163 units, estimated to increase to 180 units by 1988. This is a conservative estimate since Tuk is recognized to have a large unsatisfied demand for housing units and is high on the list of communities with priority for new construction. Since the new units are considerably more efficient than the old ones, the average annual use per unit is estimated to drop from 4,000 to 3,500 litres per unit.

The people living in housing association units do not pay directly for heating fuel. Fuel is included in the rent of the units.

PRIVATE HOUSEHOLDS

The number of private households was estimated at 5 by early 1985*, based on those having separate accounts with the POL.

* This excludes trailers that are heated electrically.

However, the number of private households can be expected to increase rapidly since 9 new lots have been assigned for construction in the past few months and another 16 are now available.

COMMERCIAL

Businesses account for almost 40 per cent of heating fuel use and have a much higher use per unit than households. Two businesses alone account for close to 30 per cents of community heating oil use.

GOVERNMENT

Government includes public buildings and staff houses and accounts for about 30 per cent of heating oil use. Several new facilities are planned, but since the smaller, less efficient older structures will probably be closed down, the net effect may well be to hold consumption constant in the near future.

TOTAL

Total consumption of heating fuel in the community is estimated to be 1.83 million litres in 1984/85, and 1.95 million litres by 1988. The monthly variation in use is shown in Table 1. In general mid-June to mid-July is the warmest time of the year and it is possible that little or no fuel is used on some days during this period. February and March are usually the coldest months. The figures shown above are based on deliveries rather than use and may not, therefore, be totally representation of use.

2.2 NCPC

NCPC now generates power for Tuk from Inuvik and transmits power along a 69 KV transmission line from Inuvik to Tuk. This line was built using untreated poles and it is now estimated that 75 per cent of the poles are rotting from the inside out. The cost of properly maintaining the line would be so high that NCPC is looking seriously at the possibility of abandoning the line and adding additional generating capacity in Tuk, supplying the community with power generated in local diesel generators. An additional 1.4 MW could be added to the existing 2.1 MW.

Total power required for Tuk in 1984 was 9.3 GWH including about 15 per cent losses in distribution and 10 per cent losses in transmission. The forecast for 1987/88 is 8.45 GWH, if power were generated locally.

Consumption of fuel by NCPC is estimated in Table 3 for 1987/88 based on this forecast. However, there is some uncertainty as to when and whether NCPC will abandon the transmission line in favour of local generation.

2.3 OIL AND TRANSPORTATION COMPANIES--BASE CAMPS

All of the oil companies generate their own heat and power at their Tuk bases from fuel that they purchase directly from suppliers. Their consumption is estimated in Table 4. This consumption is assumed to remain constant through to 1988, in the absence of evidence for plans to expand or reduce the bases. The two transportation companies, NTCL and ATL, operate only in the summertime and purchase their power from NCPC and Gulf respectively.

DOME

The Dome base generates all of its own power using 3 x 800 KW Caterpillar 399 generators. The complex is heated by glycol using 2 x 700 horsepower boilers (Cleaver-Brooks) . They do not keep separate records of fuel use for heat and power, but used a total of 2.77 million litres for both purposes in 1984/85. Dome estimates its consumption varies from a low of 4,500 litres per day from January to March and December, to 9,000 litres per day over the rest of the season.

Dome had a contract to buy power from NCPC until this year, but now generate all of their own power. They claim the cost of self generated power is considerably less than the cost of purchasing from NCPC.

GULF

Gulf generates all of its own power and heats its camp mainly using waste heat from the power plant. Gulf also has 3 x 800 KW generators of the same type that Dome has. Gulf supplies all of the power requirements of the ATL camp as well as its own. It runs a boiler to supplement the waste heat plant for an average of 3 hours per day, ranging from 1 hour to 7 hours per day. It's consumption of fuel is shown in Table 4 to be 1.5 million litres per year, varying from a low of 109,000 litres in June to a high of 146,000 litres in December. Gulf's summer load is increased because ATL's power requirements are much higher in the summer than in the winter when the camp is shut down.

ESSO

Esso was the least open in terms of information. They estimated a use of 980,000 litres in the lighting complex and utility building, mainly to power 3 x 400 KW generators. Heating is provided using waste heat from the power plant plus a separate set of boilers. An additional 320,000 litres is used in the boilers annually for heat alone. No breakdown was available on a daily or monthly basis.

NTCL

The base camp of NTCL purchases power from NCPC but uses some heating oil to heat its premises from mid-June to late October while the camp is operating and at a low level throughout the rest of the year. It's total use of heating oil is estimated at 227,000 litres in 1984.

ATL

ATL in Tuktoyaktuk purchases power from Gulf and also uses some heating oil for its boilers during the six month operating season from March to October. It's total use of heating oil is estimated at about 80,000 litres over the year. ATL's camp makes considerable use of electric heaters. It plans to double the size of the camp next year.

TOTAL--ALL COMPANIES

The total for all companies is shown in Table 4 to be almost 5.9 million litres per year. Of this, only NTCL'S demand would remain fairly steady in the case of a major slow-down in oil company activity.

2.4 TOTAL CONSUMPTION IN TUKTOYAKTUK

Table 5 summarizes the total estimated consumption of heating oil and diesel for power generation in 1984/85. The total amount consumed was 7.7 million litres of which about one quarter was consumed by the community, the remainder by the oil and transportation companies in Tuktoyaktuk. If NCPC had generated power in Tuktoyaktuk rather than Inuvik, the total could have been increased by 2.3 million litres to 10.0 million litres (see Table 6).

3. POTENTIAL VOLUME OF NATURAL GAS SALES IN TUK

Potential sales of gas are estimated in Tables 6 and 7 based on 1984/85 consumption of diesel, including an estimate of what NCPC would have used if it had generated power for Tuktoyaktuk in the community. The total potential for natural gas sales is estimated at 8.6 million cubic meters without ESSO and 9.9 million cubic meters including ESSO.

4. CURRENT PRICES OF DIESEL AND HEATING OIL IN TUK

The prices paid by the different users of heating fuel and diesel for power generation are given below:

1984/85 Prices for P-50 Diesel
cents per 1 litre

	Price	NWT Tax	Fed Tax	Total
Community - all users of heating oil	54.0	0	0	54.0
NCPC - power gen.	39.5	2.6	0	42.1
Oil Companies (DOME)	42.9	2.6	0	45.5
Transport Companies (NTCL)	38.2	-		38.2

There are no taxes on heating oil. The price given for the community is the P.O.L. price, including margins, levies, subsidies etc. The price for NTCL is estimated to be Esso's price at Norman Wells since NTCL does not charge freight costs on its own fuel. The price for oil companies is the price that DOME paid for its current supplies. Gulf said that this price would apply to their use. Esso said that they pay the bulk price in Hay River plus transportation costs, but they could not provide immediately data on prices.

None of the oil companies take advantage of the fact that no taxes are charged on heating fuel. All fuel appears to be reported as being used in the utility complexes and therefore includes a tax of 2.6 cents per litre.

No taxes are now paid on natural gas produced and consumed in the community of Norman Wells. Peter Hart of the Energy Secretariat of the NWT felt that every encouragement would be given to a gas project in Tuk and that it was virtually certain that no taxes would be charged on it as well.

The equivalent value for natural gas, assuming heating values and efficiencies as shown in Table 7 are shown below:

	$/1000 M3	$ /mc f
Community--All users	607.00	17.20
NCPC	409.00	11.60
Oil Companies (DOME)	446.00	12.63
Transport Companies	429.00	12.15

These values do not include an incentive to cover costs of converting equipment to natural gas and are very sensitive to assumptions about efficiency and future oil product prices. They also include taxes for P-50, and assume no taxes on natural gas.

5. FORECAST OF FUTURE POTENTIAL VOLUME OF NATURAL GAS SALES

A number of scenarios can be constructed in order to estimate the potential sales of natural gas from a project near Tuktoyaktuk. Five different scenarios have been selected:

1) Base Case--oil company activities continue at current levels for the next fifteen years. Growth in consumption is related mainly to increases in housing stock. NCPC generates power for Tuktoyaktuk in Tuk using gas.

2) Low Exploration Activity Case---as above except that oil company operations cease in seven years.

3) Intermediate Power Export Case--as in base case, but NCPC exports some excess power to Inuvik as well as supplying Tuk from generators in Tuktoyaktuk.

4) High Power Export Case--as in base case but NCPC supplies all power to Inuvik from Tuk.

5) Gas Export Case----as in base case, but a gas pipeline is built to Inuvik to supply gas for heating and power.

The assumptions and results of the scenarios are outlined below.

5.1 BASE CASE

The forecast for the base case is shown in Table 8, based on the following assumptions:

a) Residential use to 1987/88 is forecast according to the information in section 2.1, after 1987/88 residential use is predicted to increase at the same rate as population, i.e. 2.5 per cent per year (see Appendix, Table A-1 for population forecast) .

b) Government and commercial use is forecast to be constant to 1987/88 (a result of increasing space in facilities offset by conservation) and then to increase at the rate of 1 per cent per year .

c) Fuel use by NCPC is estimated by calculating back from forecast NCPC sales in Tuktoyaktuk and adding 15 per cent distribution losses in the town. (See Appendix, Table A-2). It is assumed that 92 per cent of all power can be generated by gas--some use of diesel back-up is inevitable. Gas consumption is estimated by assuming the same efficiency as with P-50, ie. 3.05 kwh/litre and correcting for the relative net heating value of P-50 (34.82MJ/l) and gas (33.94 MJ/M3).

d) Fuel use by oil and transportation companies is constant over time, except for a slight increase to reflect growth in ATL's camp in 1986/87.

This forecast results in an estimated gas consumption of 10.6 million M3 in 1987/88 growing to 11.6 million M3 in 1994/95 and 12.2 million M3 in 1999/2000.

5.2 LOW EXPLORATION ACTIVITY CASE

The forecast for the low exploration activity case is shown in Table 9, based on similar assumptions to those of the base case except that oil company activities are expected to terminate within 7 years.

This will not affect residential or government use since consumption in these sectors is expected to grow in relation to the natural growth of the population. Use of fuel in the commercial sector is expected to drop to 50 per cent of current levels as the oil company activities cease, then to increase at the rate of 1 per cent per year.

Fuel use of NCPC will not be affected, since they do not supply Dome, Esso, Gulf or ATL. Of the oil and transportation companies, only NTCL will continue to consume fuel at current rates. ATL's operations will terminate at the same time as those of the oil companies.

The result of these assumptions is an estimated consumption level of 9.1 million M3 in 1987/88, decreasing to 5.3 million M3 in 1994/95 then increasing to 5.9 million M3 in 1999/2000.

5.3 INTERMEDIATE POWER EXPORT CASE

Estimated total potential gas sales in this case are shown in Table 10 based on the following assumptions:

- --Community use and oil and transportation company use are based on some assumptions as in the base case.
- --Consumption of fuel by NCPC consists of two elements--fuel use to generate power for Tuktoyaktuk and fuel use to generate power for sale to Inuvik.

The potential for export of power to Inuvik is calculated in Table A-3 based on the following assumptions. First, it is possible to interconnect all of the major generating capacity in Tuk, including generators belonging to the oil companies. This capacity is all converted to use gas, causing a de-rating of 35 per cent.

If the capacity were to be fully utilized at a capacity factor of 90 per cent, annual generation could total close to 50,000 MWH compared to an annual demand in Tuk varying from 24,600 MWH in 1987/88 to 28,100 MWH in 1997/98 and 30,300 MWH in 2004/05.

This calculation indicates that there is considerable surplus capacity that could be used to generate power for sale in Inuvik. Allowing for the fact that the pattern of availability of power may not exactly match the demand, it is possible to think of exports of the magnitude of 1.2 MW on a continuous basis. (The current baseload in Inuvik averages 2-2.5 MW.)

These exports can take place as long as the existing power line between Inuvik and Tuk can be maintained at a reasonable cost and with a reasonable degree of reliability. Current annual maintenance costs on the Inuvik-Tuk line are estimated at $70,000 but this does not include any preventive maintenance and the reliability of the line is considered to be very dubious. NCPC's transmission engineer considers that the line could become inoperable any day. The cost of a new transmission line is estimated at 14 million 1981 $ for a 115 KV line.

It is therefore difficult to estimate the potential for export of power to Inuvik from Tuk, since this depends on the economics of maintaining the existing line or building a new one combined with the economics of converting and possibly adding capacity.

Since the project will not begin to operate until 1987, the line may already be closed down. Or, it may continue to function for as long as 5 years or more with adequate preventative maintenance.

The estimates contained in Table 10 assume the transmission line operates for the next five years and exports of 2 MW of power are possible during that time. The total gas demand then ranges from 14.1 million M3 in 1987/88 to 11.6 million M3 in 1994/95 and 12.2 million M3 in 1999/2000.

5.4 MAXIMUM POWER EXPORT CASE

If a new transmission line were to be constructed and all power for Inuvik were to be generated in Tuk, consumption would be much higher as shown in Table 11. (See Section 5.5 (b) and Table A-4 for calculation of generation for Inuvik and related fuel requirements).

5.5 GAS EXPORT CASE

As well as supplying the community of Tuktoyaktuk, it may be economic to build a gas pipeline to Inuvik to supply gas for all of the heating and power needs of that community. To look at this case, it was necessary to estimate the current consumption of fuel in Inuvik and forecast this into the future. An approximate estimate of current demand was made in Table A-6 and the potential gas demand is estimated in Table 12, based on similar assumptions to those in the base case for Tuk. The main assumptions are:

a) Use of residual fuel in Inuvik in NCPC boilers is expected to decrease by 10 per cent between 1985/86 and 1987/88, to reflect the fact that DND is pulling out approximately 800 people and shutting down its bases in Inuvik. While most of the residential and office space is expected to be occupied very quickly or heated to minimal levels, it is reasonable to assume a decline of 10 per cent in overall fuel use in the utilidor system. After 1987/88, use is expected to increase at the same rate as population, at 1.4 per cent per year. Private sales of heating oil are expected to increase steadily from 1984/85 at 1.4 per cent per year since DND personnel do not occupy privately heated facilities.

b) Fuel use by NCPC for power generation is based on a forecast of electricity sales that is also assumed to decrease by 10 per cent by 87/88, then increase with population. This forecast differs from NCPC's forecast which shows a net annual decline each year from 1985/86 to 2004/05, assuming DND's pull-out ripples only very gradually through the economy. 15 per cent distribution losses are added to sales. It appears more reasonable to show an immediate decline and then a recovery. Then it is assumed that 1/3 of requirements are generated using diesel at 3.05 kwh/ litre P-40 while remaining 2/3 are generated using residual fuel at 3.75 kwh/litre. Gas required to replace oil products is calculated on a straight net heating value equivalent bases, assuming no change in overall generating efficiency using gas (see Table A-7). Again, it is assumed that some use will be made of diesel back-up, so that gas is assumed to provide only 92 per cent of the power generated.

c) Potential markets for gas in Tuk are as in base case.

5.6 SUMMARY

The results of gas demand in the cases outlined are summarized in the following table:

	Million M3		
	1987/88	1994/95	1999/2000
Base Case	**10.6**	**11.6**	**12.3**
Low Exploration Activity Case	9.1	5.3	5.9
Intermediate Power Export Case	14.1	11.6	12.2
High Power Export Case	19.7	21.6	22.9
Gas Export Case	33.1	36.3	38.7

All of these estimates include the total potential market. It will be important to determine penetration rates in the different markets, ie. the rate at which customers will convert from oil to gas, and the saturation level.

6. FORECAST OF FUTURE PRICES FOR PETROLEUM PRODUCT

A critical question determining future revenues is the price of the fuel that will be replaced by natural gas. This price is influenced by several main factors: crude oil price in Edmonton or Norman Wells, the margin between crude oil prices and product prices, and the transport cost to get product from source (Edmonton or Norman Wells) to destination (Tuktoyaktuk or Inuvik).

An example for the base year (late 1985) is as follows*:

	P-50 Price to Oil and Transport Companies in Tuk	
	1985 $/bbl.	1985 $/M
Crude Oil in Edmonton (Judy Creek)	**38.25**	**240.70**
Margin Crude/P-50**	8.25	51.90
Terminalling & Freight to Hay River***	6.75	42.50
Freight Hay River/Tuktoyaktuk	14.85	93.40
Tax	4.15	26.00
Price of P-50 in Tuktoyaktuk	72.25	454.50

---

* Obtained by Earl Scott from PetroCanada in Edmonton

** Margin of crude/P40 estimated at 6.25. This was considered high in comparison to previous margins but now could be low since refiners are taking advantage of crude price drop to increase margins.

*** Composed of 5.48 freight, 1.27 termalling

The future level of each of the components of the P-50 price is indicated in Table 13 for three different scenarios.

1) Base Case--Crude oil price drops $2 in 1986, then stays constant in current dollars to 1990, increases with inflation to 1994 and then increases in real terms at 2% per year.
--Transport cost increases with inflation (reflects relationship over last 10 years, see Table A-5).
--Margin increases with inflation.

2) Low Case--Crude oil price drops to $29.25 in 1986/87 then stays constant in current dollars to 1989/90, then increases with inflation.
--Transport costs and margins are constant in real terms.

3) High Case--Crude oil price drops $2 in 1986, increases at inflation rate to 1994, increases at 2% more than inflation to 2005.
--Transport costs increase at 1.2 times inflation rate (reflects relation of past 5 years).
--Margin increases 5%/yr in real terms.

This is a forecast of prices for P-50 originating from Edmonton. For P-50 originating in Norman Wells, the transport costs would be approximately $14.50 per barrel less in 1985/86. The selling price at Norman Wells would be approximately equal to that in Edmonton.

Tables 14 through 17 contain similar estimates of product prices to different users, based on the following estimates for the base year:

ESTIMATES OF COMPONENTS OF 1985/86 PRICES
ORIGINATING FROM NORMAN WELLS
($/bbl)

	Crude Price	Margin	Transport Distrib.	Tax	Total
INUVIK					
P40	29.50	22.60	7.35	4.15	63.60
RESIDUAL	29.50	9.90	8.30	4.15	51.85
P50	29.50	31.25	7.30	0.00	68.05
TUKTOYAKTUK					
P50 (COMM.)	29.50	31.25	25.10	0.00	85.85

($/m3)

	Crude Price	Margin	Transport Distrib.	Tax	Total
INUVIK					
P40	185.55	142.35	46.10	26.00	400.00
RESIDUAL*	185.55	62.45	52.00	26.00	326.00
P 50	185.55	196.45	46.00	0.00	428.00
TUKTOYAKTUK					
P50 (COMM.)	185.55	196.45	158.00	0.00	540.00

*Residual fuel is taxed when used for power generation, but not when used for heating.

** Assumes crude price is netted back to Edmonton, with transport cost of $55/m3.

Table 1

Consumption of Heating Fuel in the Community of Tuktoyaktuk

	Base year - 1984 Annual	# Units	Average Use/Unit (000 litres)
1. Housing Assoc.	**555**	**137**	**4.0**
2. Private Households	24	5	5.0
3. Commercial	708	12	59.0
4. Government			
- NWT	**273**	**26**	**10.5**
- Hamlet	**139**	**13**	**10.7**
Federal	131	5	26.2
Sub-Total	543	44	12.3
Total	1830	200	

Monthly Deliveries All Customers	(000 litres)
Jan	260
Feb	327
Mar	353
Apr	62
May	166
Jun	89
Jul	17
Aug	93
Sep	31
Ott	90
Nov	191
Dec	151
Total	1830
Monthly Average	152

Table 2

Forecast of Fuel Use in Tuk Community, 1987/88

	Annual (000 litres)	# Units	Average Use/Unit (000 litres)
1. Housing Assoc.	630	180	3.50
2. Private Housholds	75	15	5.0
3. Commercial	708	12	59
4. Government	543	44	12.3
Total	1956	251	

Table 3

Estimated Consumption of Fuel by NCPC in Tuktoyaktuk, 1987/88

1.	Generation	8.45 GWH
2.	Fuel Efficiency	3.05 KWH/litre
3.	Fuel Consumption	2.77 millions litres
4.	Estimated Monthly Average	231,000 litres and 704 MWH
5.	Summer monthly Average	700 KW X 24 X 30 = 564 MWH and 185,000 litres
6.	Winter Monthly Average	1000 KW x 24 x 30 = 806 MWH and 264,000 litres

Table 4

Fuel Consumption of the Oil & Transportation

Companies in Tuktoyaktuk, 1984/85

(000 litres)

	Annual Consumption			Monthly Variation		
	Heat	Power	Total	Average	Summer	Winter
DOME	277*	2493*	2770	230	270	225
GULF	150*	1350*	1500	125	112	139
ESSO	320	980	1300	109	80*	130*
NTCL	227		227	19	40*	10*
ATL**	82		82	7	13	
	1056	4823	5879	490	515	504

* Estimated
** ATL will be doubling the size of its camp in 1986

Table 5

Total Estimated Consumption of Heating Oil and Diesel

1984/85

(000 litres)

	Annual	Monthly Average	Monthly Winter Average	Montly Summer Average
Community				
- Housing Corp	555			
- Private	24			
- Commercial	708			
- Government	543			
Sub-total	1830	152	229	76
NCPC				
Oil & Transport Companies				
- Dome	2770	230	225	270
- Gulf	1500	125	139	112
- NTCL	227	19	10	40
- ATL	82	7		13
Sub-total	4579	381	374	435
Total not incl ESSO	6409	533	603	511
- ESSO	1310	109	130	80
Total incl ESSO	7719	642	733	591

Table 6

Potential Sales of Natural Gas in Tuktoyaktuk

Based on 1984/85 consumption

(000 litres)

	Current Diesel Consumption			
	Annual	Monthly Average	Monthly Winter Average	Montly Summer Average
Community				
- Housing Corp	555			
- Private	24			
- Commercial	708			
- Government	543			
Sub-total	1830	152	229	76
NCPC	2267	189		
Oil & Transport Companies				
- Dome	2770**	231	225	270
- Gulf	1700	125	139	112
- NTCL	227	19	10	40
- ATL	82	7		13
Sub-total	4579	382	374	435
Total not incl ESSO	8676	723		
- ESSO	1310**	109	130*	80*
Total incl ESSO	9986	832		

* Estimated
** proportion of fuel used for heating - Dome 10%, Gulf 10%, Esso 24%, NTCL 100%, ATL 100%

Table 7

Potential Sales of Natural Gas in Tuktoyaktuk

Based on 1984/85 consumption

($000\ m^3$)

	Estimated Potential Gas Consumption *			
	Annual	Monthly Average	Monthly Winter Average	Montlhly Summer Average
Community				
- Housing Corp	494			
- Private	21			
- Commercial	630			
- Government	483			
Sub-total	1628	135	195	68
NCPC	2326	194		
Oil & Transport Companies				
- Dome	2814**	235	231	277
- Gulf	1524	127	141	114
- NTCL	202	17	9	36
- ATL	73	6		12
Sub-total	4613	385	381	439
Total not incl ESSO	8567	714		
- ESSO	1300	109	130	80
Total incl ESSO	9867	823		

	P-50 Diesel	Methane
* Net heating Value	34.82 MJ/litre	33.94 MJ/m3
Furnace/boiler efficiency	65%	75%
Consumption/kwh	11.4 MJ	11.4 MJ

TABLE 8

FORECAST OF NATURAL GAS MARKETS IN TUKTOYAKTUK (000m3)
BASE CASE-CONSTANT OIL EXPLORATION ACTIVITY

	COMMUNITY				NCPC	OIL AND TRANSPORTATION COMPANIES						TOTAL
	Resid.	Comm.	Govt.	TOTAL		NTCL	ATL	DOME	GULF	ESSO	TOTAL	
84/85	515	630	483	1628	2140	202	73	2814	1524	1300	5913	9681
85/86	550	630	483	1663	2482	202	73	2814	1524	1300	5913	10058
86/87	585	630	483	1698	2617	202	73	2814	1735	1300	6124	10439
87/88	630	630	483	1743	2734	202	73	2814	1735	1300	6124	10601
88/89	646	636	488	1770	2851	202	73	2814	1735	1300	6124	10744
89/90	662	643	493	1797	2968	202	73	2814	1735	1300	6124	10889
90/91	678	649	498	1825	3075	202	73	2814	1735	1300	6124	11024
91/92	695	656	503	1854	3181	202	73	2814	1735	1300	6124	11159
92/93	713	662	508	1883	3288	202	73	2814	1735	1300	6124	11294
93/94	731	669	513	1912	3394	202	73	2814	1735	1300	6124	11430
94/95	749	675	518	1942	3484	202	73	2814	1735	1300	6124	11550
95/96	768	682	523	1973	3581	202	73	2814	1735	1300	6124	11677
96/97	787	689	528	2004	3673	202	73	2814	1735	1300	6124	11801
97/98	806	696	534	2036	3764	202	73	2814	1735	1300	6124	11924
98/99	827	703	539	2068	3854	202	73	2814	1735	1300	6124	12047
99/2000	847	710	544	2101	3946	202	73	2814	1735	1300	6124	12172
2000/01	868	717	550	2135	4032	202	73	2814	1735	1300	6124	12291
01/02	890	724	555	2170	4118	202	73	2814	1735	1300	6124	12411
02/03	912	731	561	2205	4203	202	73	2814	1735	1300	6124	12532
03/04	935	739	566	2240	4283	202	73	2814	1735	1300	6124	12647
04/05	959	746	572	2277	4355	202	73	2814	1735	1300	6124	12756

01/02	890	363	555	1808	4118	202	0	0	0	0	202	6128
02/03	912	367	561	1840	4203	202	0	0	0	0	202	6245
03/04	935	370	566	1872	4283	202	0	0	0	0	202	6357
04/05	959	374	572	1905	4355	202	0	0	0	0	202	6462

TABLE 10

FORECAST IIF NATURAL GAS MARKETS IN TUKTOYAKTUK (000m3)
INTERMEDIATE POWER EXPORTS

	COMMUNITY				NCPC			OIL AND TRANSPORTATION COMPANIES						TOTAL
	Resid.	Comm.	Govt.	TOTAL	FOR TUK	FOR EXPORT	TOTAL	NTCL	ATL	DOME	GULF	ESSO	TOTAL	
84/85	515	630	483	1628	2140	3535	5675	202	73	2814	1524	1300	5913	13216
85/86	550	630	483	1663	2482	3535	6017	202	73	2814	1524	1300	5913	1359
86/87	585	630	483	1698	2617	3535	6152	202	73	2814	1735	1300	6124	1397
87/88	630	630	483	1743	2734	3535	6269	202	73	2814	1735	1300	6124	14136
88/89	646	636	488	1770	2851	3535	6386	202	73	2814	1735	1300	6124	1427
89/90	662	643	493	1797	2968	3535	6503	202	73	2814	1735	1300	6124	1442
90/91	678	649	498	1825	3075	0	3075	202	73	2814	1735	1300	6124	11024
91/92	695	656	503	1854	3181	0	3181	202	73	2814	1735	1300	6124	11159
92/93	713	662	508	1883	3288	0	3288	202	73	2814	1735	1300	6124	1129
93/94	731	669	513	1912	3394	0	3394	202	73	2814	1735	1300	6124	1143
94/95	749	675	518	1942	3484	0	3484	202	73	2814	1735	1300	6124	11550
95/96	768	682	523	1973	3581	0	3581	202	73	2814	1735	1300	6124	1167
96/97	787	689	528	2004	3673	0	3673	202	73	2814	1735	1300	6124	1180
97/98	806	696	534	2036	3764	0	3764	202	73	2814	1735	1300	6124	11924
98/99	827	703	539	2068	3854	0	3854	202	73	2814	1735	1300	6124	12047
99/2000	847	710	544	2101	3946	0	3946	202	73	2814	1735	1300	6124	1217
2000/01	868	717	550	2135	4032	0	4032	202	73	2814	1735	1300	6124	1229
01/02	890	724	555	2170	4118	0	4118	202	73	2814	1735	1300	6124	12411
02/03	912	731	561	2205	4203	0	4203	202	73	2814	1735	1300	6124	1253
03/04	935	739	566	2240	4283	0	4283	202	73	2814	1735	1300	6124	1264
04/05	959	746	572	2277	4355	0	4355	202	73	2814	1735	1300	6124	12756

TABLE 11

FORECAST OF NATURAL GAS MARKETS IN TUKTOYAKTUK (000m3)
HIGH POWER EXPORT CASE

	COMMUNITY				NCPC			OIL AND TRANSPORTATION COMPANIES						TOTAL
	Resid.	Comm.	Govt.	Sub-total	FOR TUK	FOR INUVIK	Sub-tot,	NTCL	ATL	DOME	GULF	ESSO	Sub-tot.	
84/85	515	630	483	1628	2140	9868	12008	202	73	2814	1524	1300	5913	19549
85/86	550	630	483	1663	2482	10106	12588	202	73	2814	1524	1300	5913	20164
86/87	585	630	483	1698	2617	9601	12218	202	73	2814	1735	1300	6124	20040
87/88	630	630	483	1743	2734	9096	11830	202	73	2814	1735	1300	6124	19697
88/89	646	636	488	1770	2851	9223	12073	202	73	2814	1735	1300	6124	19967
89/90	662	643	493	1797	2968	9352	12320	202	73	2814	1735	1300	6124	20241
90/91	678	649	498	1825	3075	9483	12558	202	73	2814	1735	1300	6124	20507
91/92	695	656	503	1854	3181	9616	12797	202	73	2814	1735	1300	6124	20774
92/93	713	662	508	1883	3288	9750	13038	202	73	2814	1735	1300	6124	21044
93/94	731	669	513	1912	3394	9887	13280	202	73	2814	1735	1300	6124	21317
94/95	749	675	518	1942	3484	10025	13509	202	73	2814	1735	1300	6124	21575
95/96	768	682	523	1973	3581	10166.	13746	202	73	2814	1735	1300	6124	21843
96/97	787	689	528	2004	3673	10308	13981	202	73	2814	1735	1300	6124	22109
97/98	806	696	534	2036	3764	10452	14216	202	73	2814	1735	1300	6124	22376
98/99	827	703	539	2068	3854	10599	14453	202	73	2814	1735	1300	6124	22645
99/2000	847	710	544	2101	3946	10747	14693	202	73	2814	1735	1300	6124	22919
2000/01	868	717	550	2135	4032	10897	14929	202	73	2814	1735	1300	6124	23189
01/02	890	724	555	2170	4118	11050	15168	202	73	2814	1735	1300	6124	23461
02/03	912	731	561	2205	4203	11205	15408	202	73	2814	1735	1300	6124	23736
03/04	935	739	566	2240	4283	11361	15644	202	73	2814	1735	1300	6124	24006
04/05	959	746	572	2277	4355	11521	15875	202	73	2814	1735	1300	6124	24276

TABLE 12

FORECAST OF NATURAL GAS MARKETS IN TUKTOYAKTUK (000m3)
GAS EXPORT CASE

	TUKTOYAKTUK			SUB	INUVIK NCPC			Private	SUB	TOTAL
	Commun,	NCFC	Companies	TOTAL	Heating	Power	Sub-tot.	Heating	TOTAL	
84/85	1628	2140	5913	9681	11342	0405	19747	4178	23925	33606
85/86	1663	2482	5913	10058	11501	8608	20109	4236	24345	34403
86/87	1698	2617	6124	10439	10926	8178	19103	4296	23399	33838
87/88	1743	2734	6124	10601	10351	7747	18098	4356	22454	33055
88/89	1770	2851	6124	10744	10496	7856	18351	4417	22768	33513
89/90	1797	2968	6124	10889	10643	7966	18608	4479	23087	33976
90/91	1825	3075	6124	11024	10792	8077	18869	4541	23410	34434
91/92	1854	3181	6124	11159	10943	8190	19133	4605	23738	34897
92/93	1883	3288	6124	11294	11096	8305	19401	4670	24070	35364
93/94	1912	3394	6124	11430	11251	8421	19672	4735	24407	35837
94/95	1942	3484	6124	11550	11409	8539	19948	4801	24749	36299
95/96	1973	3581	6124	11677	11568	8659	20227	4868	25095	36773
96/97	2004	3673	6124	11801	11730	8780	20510	4937	25447	37247
97/98	2036	3764	6124	11924	11895	8903	20797	5006	25803	37727
98/99	2068	3854	6124	12047	12061	9027	21088	5076	26164	38211
99/2000	2101	3946	6124	12172	12230	9154	21384	5147	26530	38702
2000/01	2135	4032	6124	12291	12401	9282	21683	5219	26902	39193
01/02	2170	4118	6124	12411	12575	9412	21987	5292	27279	39690
02/03	2205	4203	6124	12532	12751	9544	22294	5366	27660	40192
03/04	2240	4283	6124	12647	12929	9677	22607	5441	28048	40695
04/05	2277	4355	6124	12756	13110	9813	22923	5517	28440	41196

TABLE 13

FORECAST OF P50 PRICE TO COMPANIES IN TUK
BASE CASE
TRANSPORT COST CONSTANT IN REAL TERMS
PRODUCT MARGIN CONSTANT IN REAL TERMS

	-------------- CURRENT$/m3				-------------------------	CONSTANT
YEAR	CRUDE PRICE EDMONTON	PRODUCT MARGIN	TRANSPORT COST	TAX	TUK PRICE	$/m3 TUK PRICE
85/86	240.70	51.90	135.90	26.00	454.50	454.50
86/87	228.10	54.50	142.70	27.30	452.59	431.04
87/88	228.10	57.22	149.83	28.67	463.81	420.69
88/89	228.10	60.08	157.32	30.10	475.60	410.84
89/90	239.51	63.08	165.19	31.60	499.38	410.84
90/91	251.48	66.24	173.45	33.18	524.35	410.84
91/92	264.05	69.55	182.12	34.84	550,51	410.84
92/93	277.26	73.03	191.22	36.58	578.10	410.84
93/94	296.66	76.68	200.79	38.41	612.54	414.59
94/95	317.43	80.51	210.83	40.33	649.11	418.42
95/96	339.65	84.54	221.37	42.35	687.91	422.32
96/97	363.43	88.77	232.44	44.47	729.10	426 . 2?
97/98	388.87	93.20	244.06	46.69	772.82	430.34
98/99	416.09	97.87	256.26	49.03	819.24	434.46
99/2000	445.21	102.76	269.07	51.48	868.52	438.66
2000/01	476.38	107.90	282.53	54.05	920.85	44'2.95
01/02	509.73	113.29	296.65	56.75	976.42	447.31
02/03	545.41	118.96	311.49	59. 5?	1035,44	451.76
03/04	583.58	124.90	327.06	62 .57	1098.12	456.29
04/05	624.44	131.15	343.41	65.70	1164.70	460.91

FORECAST OF P50 PRICE TO COMPANIES IN TUK
HIGH CASE

	-------------- CURRENT$/m3				-------------------------	CONSTANT
YEAR	CRUDE PRICE EDMONTON	PRODUCT MARGIN	TRANSPORT COST	TAX	TUK PRICE	$/m3 TUK PRICE
85/86	240.70	51.90	135.90	26.00	454.50	454.50
86/87	228.10	57.09	144.05	27.30	456.54	434.80
87/88	239.51	62.80	152.70	28.67	483.67	438.70
88/89	251.48	69.08	161.86	30.10	512.52	442.73
89/90	264.05	75.99	171.57	31.60	543.21	446.90
90/91	277.26	83.59	181.86	33.18	575.89	451.23
91/92	291.12	91.94	192.78	34.84	610.68	455.70
92/93	305.68	101.14	204.34	36.58	647.74	460.34
93/94	320.96	111.25	216.60	38.41	687.23	465.14
94/95	337.01	122.38	229.60	40.33	729.32	470.13
95/96	353.86	134.62	243.38	42.35	774.20	475.29
96/97	371.55	148.08	257.98	44.47	822.08	480.65
97/98	390.13	162.88	273.46	46.69	873.16	486.21
98/99	409.63	179.17	289.86	49.03	927.70	491.98
99/2000	430.12	197.09	307.26	51.48	985.94	497.97
2000/01	451.62	216.80	325.69	54.05	1048.17	504.19
01/02	474.20	238.48	345.23	56.75	1114.67	510.64
02/03	497.91	262.33	365.95	59.59	1185.78	517.35
03/04	522.81	288.56	387.90	62.57	1261.85	524.32
04/05	548.95	317.42	411.18	65.70	1343.25	531.57

FORECAST OF P50 PRICE TO COMPANIES IN TUK
LOW CASE

	-------------- CURRENT$/m3				-------------------------	CONSTANT
YEAR	CRUDE PRICE EDMONTON	PRODUCT MARGIN	TRANSPORT COST	TAX	TUK PRICE	$/m3 TUK PRICE
85/86	240.70	51.90	135.90	26.00	454.50	454.50
86/87	184.10	54.50	142.70	27.30	408.59	389.13
87/88	184.10	57.22	149.83	28.67	419.81	380.78
88/89	184.10	60.08	157.32	30.10	431.60	372.83
89/90	193.31	63.08	165.19	31.60	453.18	372.83
90/91	202.97	66.24	173.45	33.18	475.84	372.83
91/92	213.12	69.55	182.12	34.84	499.63	372.83
92/93	223.77	73.03	191.22	36.58	524.61	372.83
93/94	234.96	76.68	200.79	38.41	550.84	372.83
94/95	246.71	80.51	210.83	40.33	578.39	372.83
95/96	259.05	84.54	221.37	42.35	607.30	372.83
96/97	272.00	88.77	232.44	44.47	637.67	372.83
97/98	285.60	93.20	244.06	46.69	669.55	372.83
98/99	299.88	97.87	256.26	49.03	703.03	372.83
99/2000	314.87	102.76	269.07	51.48	738.18	372.83
2000/01	330.62	107.90	282.53	54.05	775.09	372.83
01/02	347.15	113.29	296.65	56.75	813.85	372.83
02/03	364.51	118.96	311.49	59.59	854.54	372.83
03/04	382.73	124.90	327.06	62.57	897.27	372.83
04/05	401.87	131.15	343.41	65.70	942.13	372.83

TABLE 14

FORECAST OF P40 PRICE ININUVIK
BASE CASE
TRANSPORT COST CONSTANT IN REAL TERMS
PRODUCT MARGIN CONSTANT IN REAL TERMS

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	$/m3
85/86	185.55	142.35	46.10	26.00	400.00	400.00
86/87	173.00	149.47	48.41	27.30	398.17	379.21
87/88	173.00	156.94	50.83	28.67	409.43	371.37
88/89	173.00	164.79	53.37	30.10	421.25	363.89
89/90	181.65	173.03	56.03	31.60	442.32	363.89
90/91	190.73	181.68	58.84	33.18	464.43	363.89
91/92	200.27	190.76	61.78	34.84	487.65	363.89
92/93	210.28	200.30	64.87	36.58	512.04	363.89
93/94	225.00	210.32	68.11	38.41	541.84	366.74
94/95	240.75	220.83	71.52	40.33	573.43	369.64
95/96	257.61	231.87	75.09	42.35	606.92	372.60
96/97	275.64	243.47	78.85	44.47	642.42	375.61
97/98	294.93	255.64	82.79	46.69	680.05	378.68
98/99	315.58	268.42	86.93	49.03	719.95	381.81
99/2000	337.67	281.84	91.27	51.48	762.26	385.00
2000/01	361.30	295.94	95.84	54.05	807.13	388.24
01/02	386.60	310.73	100.63	56.75	854.71	391.55
02/03	413.66	326.27	105.66	59.59	905.18	394.93
03/04	442.61	342.58	110.95	62.57	958.71	398.37
04/05	473.60	359.71	116.49	65.70	1015.50	401.87

FORECAST OF P40 PRICE IN INUVIK
Hi GH CASE

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	$/m3
85/86	185.55	142.35	46.10	26.00	400.00	400.00
86/87	173.00	156.59	48.87	27.30	405.75	386.43
87/88	181.65	172.24	51.80	28.67	434.36	393.97
88/89	190.73	189.47	54.91	30.10	465.20	401.86
89/90	200.27	208.41	58.20	31.60	498.49	410.11
90/91	210.28	229.26	61.69	33.18	534.41	418.73
91/92	220.80	252.18	65.39	34.84	573.21	427.74
92/93	231.84	277.40	69.32	36.58	615.14	437.17
93/94	243.43	305.14	73.48	38.41	660.46	447.02
94/95	255.60	335.65	77.88	40.33	709.47	457.33
95/96	268.38	369.22	82.56	42.35	762.51	468.11
96/97	281.80	406.14	87.51	44.47	819.92	479.39
97/98	295.89	446.76	92.76	46.69	882.10	491.19
98/99	310.68	491.43	98.33	49.03	949.47	503.52
99/2000	326.22	540.57	104.23	51.48	1022.50	516.43
2000/01	342.53	594.63	110.48	54.05	1101.69	529.93
01/02	359.65	654.09	117.11	56.75	1187.61	544.06
02/03	377.64	719.50	124.14	59.59	1280.87	558.84
03/04	396.52	791.45	131.59	62.57	1382.13	574.30
04/05	416.35	870.60	139.48	65.70	1492.13	590.48

FORECAST OF P40 PRICE IN INUVIK
LOW CASE

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	$/m3
85/86	185.55	142.35	46.10	26.00	400.00	400.00
86/87	128.95	149.47	48.41	27.30	354.12	337.26
87/88	128.95	156.94	50.83	28.67	365.38	331.41
88/89	128.95	164.79	53.37	30.10	377.20	325.84
89/90	135.40	173.03	56.03	31.60	396.06	325.84
90/91	142.17	181.68	58.84	33.18	415.87	325.84
91/92	149.28	190.76	61.78	34.84	436.66	325.84
92/93	156.74	200.30	64.87	36.58	458.49	325.84
93/94	164.58	210.32	68.11	38.41	481.42	325.84
94/95	172.81	220.83	71.52	40.33	505.49	325.84
95/96	181.45	231.87	75.09	42.35	530.76	325.84
96/97	190.52	243.47	78.85	44.47	557.30	325.84
97/98	200.04	255.64	82.79	46.69	585.17	325.84
98/99	210.05	268.42	86.93	49.03	614.42	325.84
99/2000	220.55	281.84	91.27	51.48	645.14	325.84
2000/01	231.58	295.94	95.84	54.05	677.40	325.84
01/02	243.15	310.73	100.63	56.75	711.27	325.84
02/03	255.31	326.27	105.66	59.59	746.84	325.84
03/04	268.08	342.58	110.95	62.57	784.18	325.84
04/05	281.48	359.71	116.49	65.70	823.39	325.84

TABLE 15

FORECAST OF RESIDUAL PRICE IN INUVIK
BASE CASE
TRANSPORT COST CONSTANT IN REAL TERMS
PRODUCT MARGIN CONSTANT IN REAL TERMS

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	62.45	52.00	26.00	326.00	326.00
86/87	173.00	65.57	54.60	27.30	320.47	305.21
87/88	173.00	68.85	57.33	28.67	327.85	297.37
88/89	173.00	72.29	60.20	30.10	335.59	289.89
89/90	181.65	75.91	63.21	31.60	352.37	289.89
90/91	190.73	79.70	66.37	33.18	369.99	289.89
91/92	200.27	83.69	69.68	34.84	388.49	289.89
92/93	210.28	87.87	73.17	36.58	407.91	289.89
93/94	225.00	92.27	76.83	38.41	432.51	292.74
94/95	240.75	96.88	80.67	40.33	458.64	295.64
95/96	257.61	101.72	84.70	42.35	486.38	298.60
96/97	275.64	106.81	88.94	44.47	515.85	301.61
97/98	294.93	112.15	93.38	46.69	547.16	304.68
98/99	315.58	117.76	98.05	49.03	580.42	307.81
99/2000	337.67	123.65	102.96	51.48	615.75	311.00
2000/01	361.30	129.83	108.10	54.05	653.29	314.24
01/02	386.60	136.32	113.51	56.75	693.18	317.55
02/03	413.66	143.14	119.18	59.59	735.57	320.93
03/04	442.61	150.29	125.14	62.57	780.62	324.37
04/05	473.60	157.81	131.40	65.70	828.51	327.87

FORECAST OF RESIDUAL PRICE IN INUVIK
HIGH CASE

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	62.45	52.00	26.00	326.00	326.00
86/87	173.00	68.70	55.12	27.30	324.12	308.68
87/88	181.65	75.56	58.43	28.67	344.31	312.30
88/89	190.73	83.12	61.93	30.10	365.88	316.06
89/90	200.27	91.43	65.65	31.60	388.95	319.97
90/91	210.28	100.58	69.59	33.18	413.63	324.09
91/92	220.80	110.63	73.76	34.84	440.04	328.36
92/93	231.84	121.70	78.19	36.58	468.31	332.82
93/94	243.43	133.87	82.88	38.41	498.59	337.46
94/95	255.60	147.25	87.85	40.33	531.04	342.31
95/96	268.38	161.98	93.12	42.35	565.83	347.37
96/97	281.80	178.18	98.71	44.47	603.16	352.65
97/98	295.89	195.99	104.63	46.69	643.21	358.16
98/99	310.68	215.59	110.91	49.03	686.22	363.92
99/2000	326.22	237.15	117.57	51.48	732.42	369.92
2000/01	342.53	260.87	124.62	54.05	782.07	376.19
01/02	359.65	286.96	132.10	56.75	835.46	382.74
02/03	377.64	315.65	140.02	59.59	892.91	389.57
03/04	396.52	347.22	148.43	62.57	954.73	396.71
04/05	416.35	381.94	157.33	65.70	1021.32	404.17

FORECAST OF RESIDUAL PRICE IN INUVIK
LOW CASE

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	62.45	52.00	26.00	326.00	326.00
86/87	128.95	65.57	54.60	27.30	276.42	263.26
87/88	128.95	68.85	57.33	28.67	283.80	257.41
88/89	128.95	72.29	60.20	30.10	291.54	251.84
89/90	135.40	75.91	63.21	31.60	306.12	251.84
90/91	142.17	79.70	66.37	33.18	321.42	251.84
91/92	149.28	83.69	69.68	34.84	337.49	251.84
92/93	156.74	87.87	73.17	36.58	354.37	251.84
93/94	164.58	92.27	76.83	38.41	372.09	251.84
94/95	172.81	96.88	80.67	40.33	390.69	251.84
95/96	181.45	101.72	84.70	42.35	410.22	251.84
96/97	190.52	106.81	88.94	44.47	430.74	251.84
97/98	200.04	112.15	93.38	46.69	452.27	251.84
98/99	210.05	117.76	98.05	49.03	474.89	251.84
99/2000	220.55	123.65	102.96	51.48	498.63	251.84
2000/01	231.58	129.83	108.10	54.05	523.56	251.84
01/02	243.15	136.32	113.51	56.75	549.74	251.84
02/03	255.31	143.14	119.18	59.59	577.23	251.84
03/04	268.08	150.29	125.14	62.57	606.09	251.84
04/05	281.46	157.81	131.40	65.70	636.39	251.84

TABLE 16

FORECAST OF P-50 PRICE IN TUKTOYAKTUK COMMUNITY
BASE CASE
TRANSPORT COST CONSTANT IN REAL TERMS
PRODUCT MARGIN CONSTANT IN REAL TERMS

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	196.45	158.00	0.00	540.00	540.00
86/87	173.00	206.27	165.90	0.00	545.17	519.21
87/88	173.00	216.59	174.20	0.00	563.78	511.37
88/89	173.00	227.42	182.90	0.00	583.32	503.89
89/90	181.65	238.79	192.05	0.00	612.49	503.89
90/91	190.73	250.73	201.65	0.00	643.11	503.89
91/92	200.27	263.26	211.74	0.00	675.27	503.89
92/93	210.28	276.42	222.32	0.00	709.03	503.89
93/94	225.00	290.25	233.44	0.00	748.69	506.74
94/95	240.75	304.76	245.11	0.00	790.62	509.64
95/96	257.61	320.00	257.37	0.00	834.97	512.60
96/97	275.64	336.00	270.23	0.00	881.87	515.61
97/98	294.93	352.80	283.75	0.00	931.47	518.68
98/99	315.58	370.44	297.93	0.00	983.95	521.81
99/2000	337.67	388.96	312.83	0.00	1039.45	525.00
2000/01	361.30	408.41	328.47	0.00	1098.18	528.24
01/02	386.60	428.83	344.89	0.00	1160.32	531.55
02/03	413.66	450.27	362.14	0.00	1226.06	534.93
03/04	442.61	472.78	380.25	0.00	1295.64	538.37
04/05	473.60	496.42	399.26	0.00	1369.27	541.87

FORECAST OF P50 PRICE IN TUKTOYAKTUK COMMUNITY
HIGH CASE

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	196.45	158.00	0.00	540.00	540.00
86/87	173.00	216.10	167.48	0.00	556.58	530.07
87/88	181.65	237.70	177.53	0.00	596.88	541.39
88/89	190.73	261.47	188.18	0.00	640.39	553.19
89/90	200.27	287.62	199.47	0.00	687.36	565.50
90/91	210.28	316.38	211.44	0.00	738.11	578.33
91/92	220.80	348.02	224.13	0.00	792.95	591.71
92/93	231.84	382.83	237.57	0.00	852.24	605.67
93/94	243.43	421.11	251.83	0.00	916.36	620.23
94/95	255.60	463.22	266.94	0.00	985.76	635.43
95/96	268.38	509.54	282.95	0.00	1060.87	651.28
96/97	281.80	560.49	299.93	0.00	1142.22	667.84
97/98	295.89	616.54	317.93	0.00	1230.36	685.11
98/99	310.68	678.20	337.00	0.00	1325.88	703.14
99/2000	326.22	746.02	357.22	0.00	1429.46	721.97
2000/01	342.53	820.62	378.66	0.00	1541.80	741.63
01/02	359.65	902.68	401.38	0.00	1663.71	762.17
02/03	377.64	992.95	425.46	0.00	1796.05	783.61
03/04	396.52	1092.25	450.99	0.00	1939.75	806.01
04/05	416.35	1201.47	478.04	0.00	2095.86	829.40

FORECAST OF P50 PRICE IN TUKTOYAKTUK COMMUNITY
LOW CASE

YEAR	CURRENT$/m3 CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	CONSTANT $/m3
85/86	185.55	196.45	158.00	0.00	540.00	540.00
86/87	128.95	206.27	165.90	0.00	501.12	477.26
87/88	128.95	216.59	174.20	0.00	519.73	471.41
88/89	128.95	227.42	182.90	0.00	539.27	465.84
89/90	135.40	238.79	192.05	0.00	566.23	465.84
90/91	142.17	250.73	201.65	0.00	594.55	465.84
91/92	149.28	263.26	211.74	0.00	624.27	465.84
92/93	156.74	276.42	222.32	0.00	655.49	465.84
93/94	164.58	290.25	233.44	0.00	688.26	465.84
94/95	172.81	304.76	245.11	0.00	722.67	465.84
95/96	181.45	320.00	257.37	0.00	758.81	465.84
96/97	190.52	336.00	270.23	0.00	796.75	465.84
97/98	200.04	352.80	283.75	0.00	836.59	465.84
98/99	210.05	370.44	297.93	0.00	878.41	465.84
99/2000	220.55	388.96	312.83	0.00	922.34	465.84
2000/01	231.58	408.41	328.47	0.00	968.45	465.84
01/02	243.15	428.83	344.89	0.00	1016.87	465.84
02/03	255.31	450.27	362.14	0.00	1067.72	465.84
03/04	268.08	472.78	380.25	0.00	1121.10	465.84
04/05	281.48	496.42	399.26	0.00	1177.16	465.84

TABLE 17

FORECAST OF P-50 PRICE IN INUVIK
BASE CASE
TRANSPORT COST CONSTANT IN REAL TERMS
PRODUCT MARGIN CONSTANT IN REAL TERMS

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	$/m3
85/86	185.55	196.45	46.00	0.00	428.00	428.00
86/87	173.00	206.27	48.30	0.00	427.57	407.21
87/88	173.00	216.59	50.71	0.00	440.30	399.37
88/89	173.00	227.42	53.25	0.00	453.67	391.89
89/90	181.65	238.79	55.91	0.00	476.35	391.89
90/91	190.73	250.73	58.71	0.00	500.17	391.89
91/92	200.27	263.26	61.64	0.00	525.18	391.89
92/93	210.28	276.42	64.73	0.00	551.43	391.89
93/94	225.00	290.25	67.96	0.00	583.21	394.74
94/95	240.75	304.76	71.36	0.00	616.87	397.64
95/96	257.61	320.00	74.93	0.00	652.53	400.60
96/97	275.64	336.00	78.68	0.00	690.31	403.61
97/98	294.93	352.80	82.61	0.00	730.34	406.68
98/99	315.58	370.44	86.74	0.00	772.75	409,81
99/2000	337.67	388.96	91.08	0.00	817.70	413.00
2000/01	361.30	408.41	95.63	0.00	865.34	416.24
01/02	386.60	428.83	100.41	0.00	915.83	419.55
02/03	413.66	450.27	105.43	0.00	969.36	422.73
03/04	442.61	472.78	110.70	0.00	1026.10	426.37
04/05	473.60	496.42	116.24	0.00	1086.26	429.87

FORECAST OF P50 PRICE IN INUVIK
HIGH CASE

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	$/m3
85/86	185.55	196.45	46.00	0.00	428.00	428.00
86/87	173.00	216.10	48.76	0.00	437.86	417.00
87/88	181.65	237.70	51.69	0.00	471.04	427.25
88/89	190.73	261.47	54.79	0.00	506.99	437.96
89/90	200.27	287.62	58.07	0.00	545.97	449.17
90/91	210.28	316.38	61.56	0.00	588.23	460.89
91/92	220.80	348.02	65.25	0.00	634.07	473.15
92/93	231.84	382.83	69.17	0.00	683.83	485.98
93/94	243.43	421.11	73.32	0.00	737.85	499.41
94/95	255.60	463.22	77.72	0.00	796.53	513.45
95/96	268.38	509.54	82.38	0.00	860.30	528.15
96/97	281.80	560.49	87.32	0.00	929.62	543.53
97/98	295.89	616.54	92.56	0.00	1004.99	559.62
98/99	310.68	678.20	98.11	0.00	1087.00	576.46
99/2000	326.22	746.02	104.00	0.00	1176.24	594.08
2000/01	342.53	820.62	110.24	0.00	1273.39	612.52
01/02	359.65	902.68	116.86	0.00	1379.19	631.82
02/03	377.64	992.95	123.87	0.00	1494.46	652.03
03/04	396.52	1092.25	131.30	0.00	1620.06	673.17
04/05	416.35	1201.47	139.18	0.00	1756.99	695.30

FORECAST OF P50 PRICE ININUVIK
LOW CASE

	CURRENT$/m3					CONSTANT
YEAR	CRUDE PRICE NORMAN WELLS	PRODUCT MARGIN	TRANSPORT COST + DISTRIB.	TAX	TOTAL PRICE	$/m3
85/86	185.55	196.45	46.00	0.00	428.00	428.00
86/87	128.95	206.27	48.30	0.00	383.52	365.26
87/88	128.95	216.59	50.71	0.00	396.25	359.41
88/89	128.95	227.42	53.25	0.00	409.62	353.84
89/90	135.40	238.79	55.91	0.00	430.10	353.84
90/91	142.17	250.73	58.71	0.00	451.60	353.84
91/92	149.28	263.26	61.64	0.00	474.18	353.84
92/93	156.74	276.42	64.73	0.00	497.89	353.84
93/94	164.58	290.25	67.96	0.00	522.79	353.84
94/95	172.81	304.76	71.36	0.00	548.92	353.84
95/96	181.45	320.00	74.93	0.00	576.37	353.84
96/97	190.52	336.00	78.68	0.00	605.19	353.84
97/98	200.04	352.80	82.61	0.00	635.45	353.84
98/99	210.05	370.44	86.74	0.00	667.22	353.84
99/2000	220.55	388.96	91.08	0.00	700.58	353.84
2000/01	231.58	408.41	95.63	0.00	735.61	353.84
01/02	243.15	428.83	100.41	0.00	772.39	353.84
02/03	255.31	450.27	105.43	0.00	811.01	353.84
03/04	268.08	472.78	110.70	0.00	851.56	353.84
04/05	281.48	496.42	116.24	0.00	894.14	353.84

APPENDIX

TABLE A-1

FORECAST OF POPULATION IN TUK

1984	870
1985	899
1986	929
1987	959
1988	990
1989	1020
1990	1049
1991	1079
1992	1107
1993	1136
1994	1158
1995	1182
1996	1207
1997	1233
1998	1257
1999	1273
2000	1300

Average rate of increase--2.5% per year

Source: Bureau of Statistics, NWT.

TABLE A-2

FORECAST OF FUEL USE BY NCPC in TUKTOYAKTUK

	SALES (MWH)	LOSSES (MWH)	GENERATIO (MWH)	EST. DIESEL (000 1)	EST. GAS (000 m3)
84/85	6013	902	6915	181	2140
85/86	6974	1046	8020	210	2482
86/87	7353	1103	8456	222	2617
87/88	7683	1152	8835	232	2734
88/89	8010	1202	9212	242	2851
89/90	8339	1251	9590	252	2968
90/91	8640	1296	9936	261	3075
91/92	8939	1341	10280	270	3181
92/93	9238	1386	10624	279	3288
93/94	9536	1430	10966	288	3394
94/95	9790	1469	11259	295	3484
95/96	10061	1509	11570	303	3581
96/97	10320	1548	11868	311	3673
97/98	10577	1587	12164	319	3764
98/99	10830	1625	12455	327	3854
99/2000	11089	1663	12752	334	3946
2000/01	11330	1700	13030	342	4032
01/02	11571	1736	13307	349	4118
02/03	11810	1772	13582	356	4203
03/04	12034	1805	13839	363	4283
04/05	12237	1836	14073	369	4355

TABLE A-3

GENERATING CAPACITY IN TUK (MW)

	Actual	De-rated by 35%
NCPC --current	2.1	
--planned/possible	1.4	
--sub total	3.5	2.3
DOME	2.4	1.6
GULF	2.4	1.6
ESSO	1.2	0.8
TOTAL	9.5	6.3

CALCULATION OF EXCESS GENERATION, 1987/88*

	Max. Generation (GWH)	Annual Demand (GWH)	Excess (GWH)	Excess (MW Capacity)
NCPC	18,750	8,450	10,300	0.8
DOME	12,600	7,600	5,000	0.4
GULF	12,600	5,600	7,000	0.6
ESSO	10,100	3,000	7,100	0.6
TOTAL	54,050	24,650	29,400	2.3

* Assumes 90% operating factor.

TABLE A-4

FORECAST OF FUEL REQUIRED TO GENERATE ALL ELECTRICITY
REQUIRED FOR INUVIK IN TUK

	SALES (MWH)	LOSSES (MWH)	GENERATIO (MWH)	EST. DIESEL (000 l)	EST. GAS (000m3)
84/85	25207	6680	31887	836	9868
85/86	25816	6841	32657	857	10106
86/87	24525	6499	31024	814	9601
87/88	23234	6157	29392	771	9096
88/89	23560	6243	29803	782	9223
89/90	23890	6331	30220	793	9352
90/91	24224	6419	30643	804	9483
91/92	24563	6509	31072	815	9616
92/93	24907	6600	31507	826	9750
93/94	25256	6693	31948	838	9887
94/95	25609	6786	32396	850	10025
95/96	25968	6881	32849	862	10166
96/97	26331	6978	33309	874	10308
97/98	26700	7075	33775	886	10452
98/99	27074	7175	34248	898	10599
99/2000	27453	7275	34728	911	10747
2000/01	27837	7377	35214	924	10897
01/02	28227	7480	35707	937	11050
02/03	28622	7585	36207	950	11205
03/04	29023	7691	36714	963	11361
04/05	29429	7799	37228	976	11521

TABLE A-5

CALCULATION OF RELATIVE INFLATION IN TRANSPORT

	HISTORIC RATES HAY RIVER TUK (c/100 lb)	RATE OF INCREASE (%)	GNE IMPLICIT PRICE INDEX (1970 BASE)	RATE OF INCREASE (%)	RATIO TRANSPOR INCREASE TO GNE INCREASE
74	243		122.8		
75	279	15	137.1	12	1.29
76	321	15	147.2	7	2.04
77	321	0	158.4	8	0.00
78	321	0	170	7	0.00
79	347	8	185.6	9	0.87
80	399	15	205.2	11	1.42
81	459	15	233.2	14	1.10
82	523	14	258.4	11	1.30
83	560	7	273.8	6	1.17
84	588	5	284.7	4	1.26
85	641	9			

TABLE A-6

CURRENT USE OF FUEL FOR HEATING AND POWER GENERATION IN INUVIK AND POTENTIAL SALES OF GAS

		CURRENT USE (0001)		POTENTIAL GAS USE (000m3)		
				FOR	FOR	TOTAL
		P40+P50	RESIDUAL	P40+P50	REsIDUAL	
NCPC	-power	3136	517?	2545	5860	8405
	-heating		10025		11342	11342
	-sub-total	3136	15204	2545	17202	19747
PRIVATE SALES		4700	-	4178	-	4178
TOTAL		7836	15204	6723	17202	23925

1. Excludes fuel required to generate fuel for Tuk.

2. Power requirements calculated by adding 15 per cent to Inuvik sales, for losses in distribution in the town, assuming 1/3 requirements supplied using diesels, 2/3 steam.

3. Assumes NCPC has 70 per cent of heating load through the utilidor.

4. Assumes no efficiency difference on NCPC use. Efficiency on private sales assumed to increase from 65 % with oil to 75 % with gas.

5. Heat Contents (Net):

P40	35.45 MJ/litre
P50	34.82 MJ/l
Resid.	38.4MJ/l
Gas	33.94 MJ/m3

TABLE A-7

FORECAST OF GAS REQUIRED TO GENERATE POWER IN INUVIK
FOR INUVIK

	SALES (MWH)	LOSSES (MWH)	GENERATIO (MWH)	P40 (000) !	EST. GAS (000m3)
84/85	25207	3781	28988	251	8405
85/86	25816	3872	29688	257	8608
86/87	24525	3679	28204	244	8178
87/88	23234	3485	26720	231	7747
88/89	23560	3534	27094	235	7856
89/90	23890	3583	27473	238	7966
90/91	24224	3634	27858	241	8077
91/92	24563	3684	28248	245	8190
92/93	24907	3736	28643	248	8305
93/94	25256	3788	29044	251	8421
94/95	25609	3841	29451	255	8539
95/96	25968	3895	29863	258	8659
96/97	26331	3950	30281	262	8780
97/98	26700	4005	30705	266	8903
98/99	27074	4061	31135	269	9027
99/2000	27453	4118	31571	273	9154
2000/01	27837	4176	32013	277	9282
01/02	28227	4234	32461	281	9412
02/03	28622	4293	32915	285	9544
03/04	29023	4353	33376	289	9677
04/05	29429	4414	33843	293	9813

APPENDIX 8.

Guidelines for Distribution Applicants in the Matter of an Application for a Franchise to Distribute Natural Gas in the Town of Hay River, NWT . (Public Utilities Board of NWT).

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

- AND -

THE TOWN OF HAY RIVER

GUIDELINES FOR DISTRIBUTOR APPLICANTS IN THE MATTER OF AN APPLICATION FOR A FRANCHISE TO DISTRIBUTE NATURAL GAS IN THE TOWN OF HAY RIVER, N.W.T.

YELLOWKNIFE
JULY 1983

INTRODUCTION

The Town Council of the Town of Hay River, Northwest Territories (the Town Council) has received applications for a natural gas distribution franchise from two utility companies, namely:

Inter-City Gas Utilities Ltd.
Northland Utilities - NW? Limited

The Town Council has requested assistance from the Public Utilities Board of-the Northwest Territories (the Board), to examine each party's ability to undertake the project and to make its recommendations to the Town Council in the best interests of the prospective consumers in the Town of Hay River, and the surrounding area.

Each distributor applicant (Applicant) will be asked to provide the Board with a formal submission in line with certain criteria and guidelines enclosed herewith. This may mean that the submissions already tendered to the Town Council will require some additional work to conform to these guidelines. The submission should be forwarded to the Board by September 15, 1983.

The Board intends to hold investigations commencing at a date and time to be set down, following a review of all material. Each applicant will be asked to appear in support of its submission and to respond to questions.

The guidelines which follow set out minimum criteria for the principal areas of concern to the Board. The Applicant, however, need not limit its submission if there are additional aspects it feels should be brought before the Board for consideration.

The following list outlines the key sections of the guidelines which should be addressed within the Applicant's formal submission of material. They are:

1. Proposed Franchise Agreement
2. Natural Gas Service Area
3. Market and Capital Expenditure Forecasts
4. Financial Ability and Administrative Policies
5. Billing, Accounting, and Collection Practices
6. Employment Policies and Training Programs
7. System Design and Construction
8. Operation and Maintenance Practices and Policies
9. Sales Promotion and Marketing Policies
10. Gas Supply

The Board is hopeful of reaching a decision and making a recommendation to the Town of Hay River in November of 1983.

GUIDELINES RELATING TO THE SUBMISSION
OF APPLICATIONS FOR A NATURAL GAS
DISTRIBUTION FRANCHISE IN THE TOWN OF
HAY RIVER, NORTHWEST TERRITORIES

The following guidelines have been developed to set out for the Applicant some of the areas of utility operations considered by the Board to be significant in carrying out its evaluation of the submissions. They are to be considered minimal criteria and the Applicant should not be limited by the guidelines in the preparation of its formal submission.

Essentially the guidelines have been organized to cover the Applicant's feasibility studies, service areas, operating practices, employment policies, design criteria and maintenance practices that would be adopted by the Applicant if it ultimately were to become a distributor of natural gas in the Northwest Territories.

Metric units and current dollars shall be used throughout the submission.

Twelve copies of the application to the Board and information and particulars required to be filed in support thereof shall be filed with the Board.

1. PROPOSED FRANCHISE AGREEMENT

It is essential that a mutually satisfactory working agreement between the selected distributor and the Town of Hay River and any other town or village it intends to-service, be in place before construction is undertaken. The Agreement, among other things, is intended to permit the distributor to use the streets, roadways, and boulevards of each community for the placement of distribution mains and service lines, the right to repair and replace mains, and the right to undertake any maintenance work as required.

The Applicant is requested to provide the Board with a draft of a proposed agreement covering such items as:

1.1 The term of the Agrement and renewal provision.

1.2 The procedure for obtaining approval for installation of mains and services in the community.

1.3 The responsibility for the restoration of roads, streets, sidewalks, boulevards, etc.

1.4 The payment for the cost of any line. relocation work following installation.

1.5 Liability of the parties to the Agreement in regard to damage to underground piping or structures.

2. NATURAL GAS SERVICE AREAS

The Board is interested in the Applicant's views relating to criteria and timing for service to other communities that will be adjacent to the proposed transmission line that will bring natural gas to Hay River.

Further, the Applicant is requested to address the possibility of future extension of the transmission line to service other communities beyond Hay River. In this respect the Applicant should clearly state its corporate plans relating to:

2.1 Communities that it would initially service.

2.2 Communities or areas that it would seek to service within a 5-year time frame.

2.3 Economic policiies relating to ditributor-owned transmission laterals.

1

3. MARKET AND CAPITAL EXPENDITURE FORECASTS

The Board is interested in reviewing the Applicants' current forecast for the 5-year period commencing 1984, relating to the following:

3.1 The estimated number of year-end natural gas customers by class of consumer and location, including the estimated present market potential, residential and commercial customer growth rates, and industrial growth forecasts.

3.2 The estimated natural gas sales volumes relating to the above, detailing the forecast use per customer and any expected increase or decrease during the period.

3.3 The estimated natural gas sales volumes that might be available from the conversion of diesel generator facilities in the communities.

3.4 The estimated natural gas purchase volumes and maximum daily requirements.

3.5 The projections of capital cost of facilities, showing expenditures for each year. The forecast should identify franchise and development costs, costs for distribution mains, service lines, buildings, heavy work equipment, and transportation equipment. Estimated engineering, supervision, administration, and overhead charges should be shown separately.

3.6 The estimated operating expenses relating to the costs of operations, maintenance expense, customer accounting, billings, sales promotion, and administration costs.

3.7 The Applicant's calculation of mid-year rate base for the five-year period, including working capital allowance.

3.8 A forecase of the cost of purchased gas.

3.9 A forecast of the Applicant's cost of service for the period, detailing the level of earned return, income taxes, operating and maintenance expense, depreciation expense, head office or parent company administration charges, billing and accounting costs, and sales promotion.

NOTE: A the present time, eligibility criteria for federal assistance under the Distribution System Expansion Program (DSEP) does not include proposed distribution systems in the Northwest Territories. However, the Government of the Northwest Territories intends to apply for inclusion in the program and indications are favorable that such assistance will be made available.

In the event that such assistance is made available, the Applicant should include an estimate of the adjustments that would apply to its capital expenditure forecast.

"4. FINANCIAL ABILITY AND ADMINISTRATIVE POLICIES

The Board is interested in receiving **information relating to the financial strength of the company, and its administration and** service management policies. The Applicant should provide a general overview of the operating experience and background at the senior management level of the Company.

Information should also be provided as follows:

4.1 What form of corporate structure will be used:

- a stand-alone company incorporated in the N.W.T.
- a branch office or subsidiary operation of an existing utility in another area

4.2 Recent financial statements of the Company, If the Applicant is a subsidiary company it should provide the financial statements of the parent company. If the Applicant is a new company, pro-forma financial statements should be provided.

4.3 Pro-forma financial statements reflecting completion of construction of the distribution system.

4.4 A proposed plan of financing the operation for the first five years including the amount, type and epxected cost of debt capital, and the amount and ownership of equity capital. The Applicant should also indicate its expected return on equity.

4.5 The proposed rates of depreciation based on intitial capital cost for the different classes of capital assets.

4.6 The Applicant's suggested policy with respect to capitalizing interest during construction.

4.7 The location of the head office of the utility. If the proposed head office is to be in other than Hay River, the method to be followed for the allocation of administration head office charges to the utility in Hay River.

4.8 The material purchasing policies and location of principal purchasing authority.

4.9 The level of liability insurance proposed to be carried by the Applicant.

5. BILLING, ACCOUNTING, AND COLLECTION PRACTICES

The Board is interested in matters relating to the practices or procedures to be followed by the Applicant in regard to the following:

5.1 The frequency of meter reading and billing proposed for residential, commercial and industrial accounts in the utility operation.

5.2 The basic format of the rate schedules that would apply to residentail, commercial and industrial customers, including such items as unites of measurement, minimum bills, late payment penalties, equal. payment plan, etc.

5.3 Gas service shut-off policies.

5.4 The proposed location of the billing and accounting centre of the utility operation.

5.5 Procedures for the collection of customers accounts.

5.6 information relating to training programs for billing " and accounting personnel.

6. EMPLOYMENT POLICIES AND TRAINING PROGRAMS

It is considered essential that trained and experienced key personnel be available initially to ensure a level of safe and acceptable service in all areas of the proposed natural gas distribution operations. The Board wishes to know from the Applicant the number of key technical personnel that would be transferred from other operations for the training and familiarization of new utility employees. The Applicant should also provide an outline: of the training programs and policies to be followed in connection with the different functions of gas utility distribution operations, how the training of employees is to be handled within the utility, and an estimate-of time required to assemble a complete operating staff.

If consulting and advisory services are required to carry out the work, the Applicant should clearly indicate how this function will be handled within the company and what principal areas of responsibility will be handled by consultants.

The general hiring policy should also be outlined in order to provide information as to the number of residents that may be ultimately employed in the operations.

7. <u>SYSTEM DESIGN AND CONSTRUCTION</u>

The Applicant is requested to describe in general terms, the method used for the design of the distribution system. Such design should include the pressures proposed and type of pipe, whether steel or plastic, that will be used.

Information is requested relating to the following:

7.1 The size, wall thickness and grade of steel and/or plastic pipe proposed for use in the system, and where it is planned for installation.

7.2 The type of pipe coating proposed for steel pipe used in the system.

7.3 The material standards used for the selection and purchase of valves, fittings, regulators, and metering.

7.4 Provide a preliminary construction plan or schedule indicating the timing and level of construction of the system.

7.5 The proposed number and size of construction crews that would be employed in the installation of the system.

The proposed number and size of construction crews that would be employed on service line installation.

The number of "owner inspectors" required and an outline of the general organization of owner's inspection operations.

7.6 The proposed methods that the Applicant will follow the protect the environmental resources, including archeological resources, clearing practices, erosion control , re-vegetation measures, fish and wildlife, and water disposal from hydrostatic testing.

8. OPERATING AND MAINTENANCE PRACTICES AND POLICIES

The Applicant is requested to describe the proposed organizational plan developed for operating and maintaining the utility system. The Applicant should provide information regarding the following:

8.1 The number and location of consumer service and sales personnel.

8.2 Customer service policies and charges relating thereto.

8.3 Proposed policy, including response time, relating to emergency situations such as line breaks, gas leaks and outages.

8.4 Proposed leak surveys to be undertaken on a regular basis and the type of equipment that will be utilized.

8.5 Proposed policy relating to regular inspection of public buildings throughout the service area.

8.6 Proposed location of meter repair and testing facilities,

9. SALES PROMOTION AND MARKETING POLICIES

The Applicant is requested to provide an outline of its proposed sales organization and location of personnel to achieve market penetration. Such an outline should include the follwoing information:

9.1 What policies might be adopted in connection with the sale and/or rental of natural gas appliances. Is it the Applicant's intention to market appliances and equipment directly or leave such marketing to local **dealers and merchants.**

9.2 Industrial natural gas sales are a significant component of a distribution system, and it is essential that this market segment be developed quickly and efficiently.

Please outline the form of industrial contracts and the underlying tariff principles proposed for this market segment.

Does the Applicant intend to negotiate separate industrial tariff schedules or would it propose to have a common tariff in plkace.

9.3 Various Federal Government incentive programs are available to assist in reducing the use of oil in Canada. One program that has particular significance in the area involves the rep acement of diesel fuel for the generation of electricity.

The Applicant is requested to outline what investigations have been made to incorporate such incentive programs in its marketing policies.

10. GAS SUPPLY

The cost of purchased gas constitutes the largest component of the total cost of service of a natural gas utility company, comprising over 80% of the cost to the consumer.

With respect to the supply of natural gas to Hay River and the surrounding area, the Applicant is requested to comment on the following:

10.1 The source and security of supply of natural gas and the level of the commitment by the supplier.

10.2 The proposed routing of the transmission line from the source of supply to Hay River, including the location of compressor and gate stations. The proposed schedule of construction should also be included.

10.3 The location and responsibility for construction of transmission laterals.

10.4 A forecast of daily contract volumes and purchase load factors for a five-year period.

10.5 The impact of potential electric generation sales and industrial sales on load factor and cost of purchased gas.

10.6 Assuming markets develop as forecasted, the need for distributor-owned storage or peak shaving facilities.

APPENDIX 9.

Scoping Study for Tuktoyaktuk Gas Project

R.T.M. Engineering Ltd. January, 1986.