3. NORTH SLOPE GAS RESOURCE UTILIZATION OPTIONS

This section provides an overview of conversion and transportation options for utilization of North Slope gas resources. Liquid conversion options are described and factors impacting the LNG and GTL options are discussed.

3.1 Gas Utilization Overview

One of the two principal options discussed for utilizing ANS gas requires a gas pipeline to a southern Alaska port where gas is converted to LNG for shipment by LNG tankers. The other option is GTL conversion of gas to hydrocarbon liquids which, if made on the North Slope, could be shipped to market with the ANS crude oil. Although there are a number of approaches to GTL conversion, those that are the most established involve Fischer-Tropsch (FT) synthesis gas technology. This study makes the assumption that current state-of-the-art FT technology would be used for GTL conversion on the North Slope. However, current research efforts by industry and the DOE Gas-to-Liquids program to develop improved FT technology and alternative conversion processes appear promising and may yield technology advances in time to be of significance before the final decisions are made for major gas sales from the North Slope. Both LNG and GTL conversion options have advantages and disadvantages that need to be considered in determining the optimum North Slope gas utilization option.

Remote gas refers to gas that is distant from consuming markets and is not marketable via existing or easily built gas pipelines connecting to a distribution system for delivery to customers. Gas value is established by competitive fuel prices in the consuming market and, if transportation costs to market are high, the value at the production site will be low. This is the case for the ANS gas resource, which has much in common with other remote gas resources around the world; i.e., the economic return has not been thought to be adequate to support development needed to get the gas to world markets. The major ANS gas owners (Arco Alaska, BP Exploration, and Exxon) reported July 1995 at the conclusion of a recent joint 2-yr study that it remains uneconomic to build a pipeline to bring ANS gas to market, but they remain committed to the project and believe there will be a window of opportunity for the pipeline after 2005 (Energy Daily, 1995; Oil Daily, 1995a). In the interim, gas from PBU will continue to be used for improving oil recovery in PBU and other ANS fields, such as in the Kuparuk River Unit (KRU) as evidenced by the recent announcement of the Large Scale Miscible Injection (LSMI) project that will purchase miscible injectant from PBU for KRU injection (Petroleum Information Corp., 1994a). The value of the gas for enhancing oil recovery can

be expected to decrease over time as ANS oil fields mature, which will increase the incentive to develop an economic means of getting the gas to market.

To use natural gas directly as a gaseous fuel without first going to LNG or hydrocarbon liquids requires a suitable market, a gas pipeline for delivery to the distribution system, and a distribution system for delivery to customers. Natural gas cannot be transported in oil pipelines; thus, a separate gas pipeline is required. For remote gas resources, where pipeline-to-market costs would be prohibitive, conversion to a liquid form, termed LNG, by simple liquefaction to a low-pressure cryogenic liquid at -160°C for transportation in LNG tankers followed by subsequent revaporization to a gas at the market site has generally been the development option used (Fox, 1988). The alternative of converting the gas to a liquid form by a chemical conversion process that converts the methane to a higher molecular weight hydrocarbon that is liquid at normal ambient conditions (i.e., a GTL conversion process) enables transport of the gas in conventional oil pipelines and tankers. The type of process chosen (LNG or GTL conversion) depends on conversion costs, transportation costs, and current and perceived future market values of the various liquid fuels into which gas can be converted. LNG is vaporized back into a gaseous state for use in the gas market, whereas GTL products remain liquid and enter directly into the oil market. The market values of the various liquid choices are discussed in **Section 4.**

In the case of the remote gas on the North Slope of Alaska, there is an added consideration to the type of liquid chosen. Because of the existence and excess capacity of TAPS and the existing oil products market and distribution system, conversion of the natural gas in an ANS GTL conversion plant to a hydrocarbon liquid that is compatible with the produced oil being transported in TAPS and compatible with existing tankers is an attractive alternative for utilization of the North Slope gas resource, provided it is economically viable. Such a development option could be built either rapidly or be undertaken more slowly in a stepwise manner, which would provide the opportunity for improvements in technology and reductions in costs for later modules. Conversely, for the LNG option, an 800-mi gas pipeline to transport ANS gas to a LNG plant, a LNG plant, and a marine transportation terminal will have to be constructed, and a LNG tanker fleet acquired up front in order to market LNG. This significant up-front cost is a financial requirement that the LNG option must support in its competition with other LNG projects throughout the world, and with other options for marketing North Slope gas. Still, LNG technology is a proven technology and may be perceived as a lower risk option than GTL conversion processes that are not as technically mature.

3.2 Gas Pipeline Options

Since the discovery of the Prudhoe Bay field in 1968, numerous plans and ideas have been proposed for developing markets and a transportation system for North Slope gas. These proposals have generally been to transport the ANS gas by gas pipeline either directly to gas markets in the U.S. lower 48 states (Lower 48) or to an LNG facility for liquefaction and transport by LNG tanker to an LNG market.

The earliest option considered was the Alaskan Natural Gas Transportation System (ANGTS), which would have required a 2,102-mile pipeline through Alaska and Canada to markets in the Lower 48. This option is not economically viable at current gas market conditions, which reflect continuing surpluses of Canadian and Lower 48 gas supplies.

Currently the most talked about concept for gas sales is the Trans-Alaska Gas System (TAGS). As promoted by Yukon Pacific Corporation (YPC), this option calls for construction of a gas-conditioning plant on the North Slope, an 800-mile pipeline, a LNG plant and marine terminal near Valdez, Alaska, and a LNG tanker fleet to transport LNG to Japan and other Pacific Rim countries for market.

As part of a recent study, the North Slope operators included the options of gas pipelines to LNG plants at either of two ports on the northwestern coast of Alaska, Wainwright or Kivalina (Oil Daily, 1995a), to reduce the capital costs involved in building the 800-mi gas pipeline in the YPC LNG project. However, these optional routes would require the use of ice-breaking LNG tankers, which is a technology that would have to be developed (Energy Daily, 1995). The joint study by Arco Alaska, BP Exploration, and Exxon concluded that all gas pipeline options remain uneconomic at this time, but they believe there will be a window of opportunity for the pipeline after 2005, when demand in Asia may justify the project. YPC believes that further study will show that the southern route to Valdez will be the only feasible route for a pipeline (Energy Daily, 1995). The YPC LNG project is assumed as the model for the LNG option examined in this evaluation.

Although large LNG markets exist in Pacific Rim countries, (a) low world oil and gas prices, (b) potential competition from overseas projects (e.g., Qatar, Natuna, and Sakhalin), (c) the large initial investments required for a gas pipeline/LNG plant, and (d) technical and economic uncertainty about when major gas sales should begin from PBU continue to delay ANS gas sales development.

3.2.1 Alaskan Natural Gas Transportation System (ANGTS).

The ANGTS scenario is a 2,102-mile pipeline (DOE, 1991) linking ANS gas production through Alaska and Canada to markets in the Lower 48. The pipeline would run parallel to TAPS from the North Slope to central Alaska and then across Canada where it would connect to the existing prebuilt section of ANGTS that is in service. This section, with a northern terminal at Caroline, Alberta, is comprised of 576 miles of pipeline and in 1994 transported 850 BCF of Canadian gas to the U.S. Numerous permits, right-of-ways, and approvals have been obtained for the proposed pipeline route through Canada and Alaska. Extensive studies have been conducted in pursuit of technological advances with the goal of reducing costs for transporting ANS gas to markets in the Lower 48.

A recent estimate of the cost to construct the ANGTS pipeline segments linking ANS gas production to the existing northernmost terminal at Caroline, Alberta is $16.7 billion (1995$) (ANGTS, 1995). Advanced technology could reduce this estimate to between $11.7 and $14.7 billion. The cost of service to deliver the gas to market ranges from a high of $4.17/MCF to a low of $2.82/MCF (ANGTS, 1995). Based on an average current sales price of $2.11/MCF for U. S. natural gas at the wellhead (EIA, 1995), it appears unlikely that this project will be pursued any time in the near future. No further analysis on this option is included in this study.

3.2.2 Trans-Alaska Gas System (TAGS) LNG Project

The TAGS project as proposed by YPC is used as the model for evaluation in this study. The TAGS scenario is a $14 billion (1/1/95$) system consisting of a gas-conditioning plant on the North Slope; an 800-mile, 42-inch, chilled, buried pipeline; a LNG plant and marine terminal at Valdez; and a LNG tanker fleet. LNG would be transported to Japan and other Pacific Rim countries. YPC has obtained major permits for construction of TAGS and export of ANS natural gas to Asia (YPC, 1995). TAGS has received the Final Environmental Impact Statement (EIS) prepared by the Federal Energy Regulatory Commission (FERC) for the LNG facility and terminal (FERC, 1995). The EIS is yet to be prepared for the pipeline. The TAGS design takes advantage of the following: (a) the existing infrastructure on the North Slope for construction and operation of a gas plant to pre-condition the gas; (b) the TAPS right-of-way and haul road for construction and operation of the gas pipeline; (c) a year-round ice-free port at Anderson Bay, Valdez, Alaska, for its gas liquefaction plant and shipping terminal sites; (d) the in-place environmental and maritime protection practices at Valdez; (e) the use of LNG tankers for transport (a well proven technology); and (f) an

established and growing LNG market in Japan and other Pacific Rim countries (see **Section 4.2**). Construction of the project depends on obtaining long-term sales and purchase contracts with the North Slope owners for the gas supply and the LNG buyers in Asia. YPC believes the large scale of the project, which requires 2.05 BCFPD of ANS gas to yield 14 million metric tons of LNG annually (MMTPA) or about 1.87 BCFPD, will create an economy of scale that will allow this gas to be competitive with other LNG projects that do not have to support the construction of an 800-mile gas pipeline. Its current design is for a 42-inch line that can be boosted to a capacity of 25 MMTPA (3.3 BCFPD) through the addition of 5 to 7 more compressor stations, if the market should become available (Alaska Conservation Foundation, 1994).

3.3 Gas-To-Liquids Conversion Processes

The purpose of this section is to provide a brief review of the current state of the art for converting natural gas to hydrocarbon liquids.

3.3.1 Overview

GTL conversion processes to fully exploit remote natural gas resources around the world have received a great deal of interest and research in recent years (OGJ, 1995; Shields, 1985; Tijm, 1993; Eisenberg, 1994). **Figure 3.1** gives an overview of the major processes for converting natural gas to liquid fuels. Natural gas can be (a) converted to LNG; (b) converted to synthesis gas [mixture of carbon monoxide (CO) and hydrogen (H_2) - frequently termed "syngas"], which is then converted to a variety of liquid fuels; or (c) reacted directly to produce other intermediates, which in turn are converted to liquid fuels.

A fundamental problem in converting natural gas into other commercial products is the chemical stability of the methane molecule. The bonds in methane are among the most unreactive of any of the hydrocarbons. Reactions that convert methane to other chemical forms are usually irreversible and difficult to control. For example, combustion or complete oxidation gives carbon dioxide and water (CO_2 and H_2O), neither of which can be used as a fuel. Therefore, the more conventional indirect GTL processes first convert the natural gas to a synthesis gas (CO and H_2) by steam reforming under a set of reaction conditions designed to only partially oxidize the methane to CO and H_2. Then, other reaction conditions are provided such that synthesis gas is converted to liquid hydrocarbon products. A FT catalytic process is frequently used for the conversion step from synthesis gas to gasoline, diesel, or other liquid products or combinations of products.
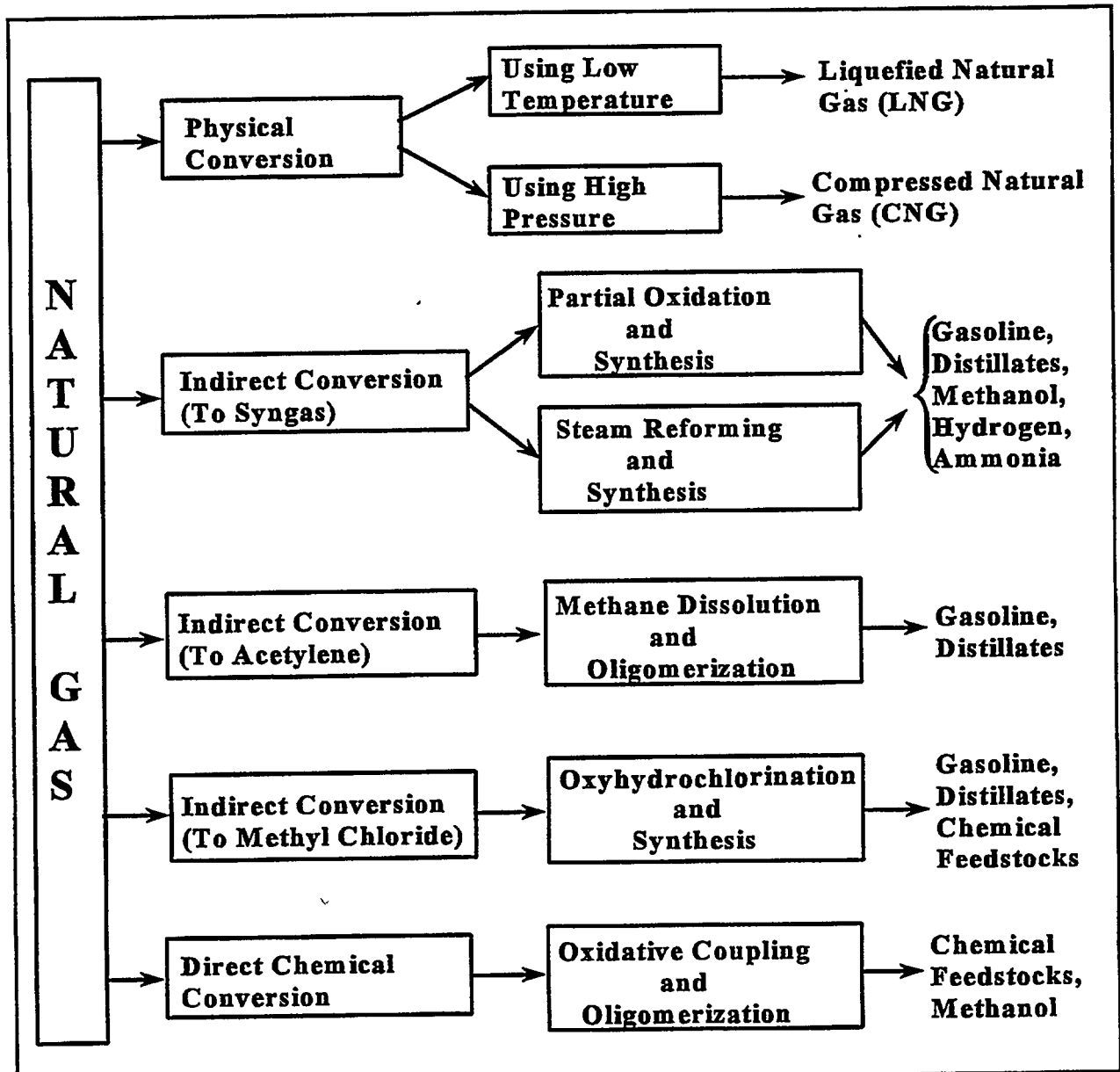
```
                    ┌──────────────┐        Liquefied Natural
                 ┌─▶│ Using Low    │──────▶ Gas (LNG)
┌──────────────┐ │  │ Temperature  │
│ Physical     │─┤  └──────────────┘
│ Conversion   │ │  ┌──────────────┐        Compressed Natural
└──────────────┘ └─▶│ Using High   │──────▶ Gas (CNG)
                    │ Pressure     │
                    └──────────────┘
```

Figure 3.1 — Processes for conversion of natural gas to liquid fuels.

- **Physical Conversion**
  - Using Low Temperature → Liquefied Natural Gas (LNG)
  - Using High Pressure → Compressed Natural Gas (CNG)
- **Indirect Conversion (To Syngas)**
  - Partial Oxidation and Synthesis
  - Steam Reforming and Synthesis
  - → Gasoline, Distillates, Methanol, Hydrogen, Ammonia
- **Indirect Conversion (To Acetylene)**
  - Methane Dissolution and Oligomerization → Gasoline, Distillates
- **Indirect Conversion (To Methyl Chloride)**
  - Oxyhydrochlorination and Synthesis → Gasoline, Distillates, Chemical Feedstocks
- **Direct Chemical Conversion**
  - Oxidative Coupling and Oligomerization → Chemical Feedstocks, Methanol

Figure 3.1. Processes for conversion of natural gas to liquid fuels.

Other indirect conversion approaches include: oxyhydrochlorination, where chlorine reacts with methane to form the building block of methyl chloride; and methane pyrolysis, where methane is injected into a hydrogen plasma and broken down to form an intermediary product - acetylene, which is then converted to liquid hydrocarbon products. Direct methane conversion processes also exist but tend to be more complex and limited more to yields of simpler and lower-valued chemical feedstocks. An R&D objective for some years has been to find direct, and also indirect, conversion processes that are less

expensive that the synthesis gas route (Fox, 1990). However, at the present stage of development, none match the FT synthesis gas conversion process in liquid yield and cost (Hackworth et al. - DOE, 1995).

Discussion of the GTL conversion processes that have some commercialization history, FT synthesis gas and methane pyrolysis, follows along with observations about prospective improvements potentially forthcoming in the near term.

3.3.2 Synthesis Gas Conversion Processes

A number of GTL processes that start with the synthesis gas step have achieved some degree of commercial success. Methanol is being produced from synthesis gas in many commercial plants by methods such as the ICI and Lurgi processes (Fox, 1988). A significant volume of methanol is then used in the production of MTBE, silicones, and other products.

The conversion of natural gas to hydrocarbon liquids suitable for transportation fuels reached commercialization in 1985 in New Zealand with the Gas-to-Gasoline (GTG) project using the Mobil Methanol to Gasoline (MTG) process. This plant first produces methanol from synthesis gas and then converts it into gasoline using a zeolite catalyst (Shields, 1985; Eisenberg, 1994). The first natural gas to fuels project in South Africa was commissioned in 1992 by the South African Coal, Oil and Gas Corporation (SASOL) at Mossel Bay. This FT plant uses the Lurgi combined reforming process for synthesis gas production, followed by SASOL's Synthol reactor technology and a variety of olefin conversion processes to produce finished fuel products (Eisenberg, 1994). In 1993, a FT-type plant was constructed in Malaysia to convert natural gas to diesel fuel using the Shell Middle Distillate Synthesis (SMDS) process (Eilers, 1990; Tijm, 1993; OGJ, 1995).

Exxon has developed and pilot tested a process designated AGC-21 that uses a three-step process including: (1) a fluidized bed synthesis gas generator, (2) a multi-phase slurry reactor combined with a high performance catalyst system for hydrocarbon synthesis, and (3) a fixed bed hydroprocessing step resulting in a refinery feedstock that can be readily shipped by pipeline or conventional crude oil tanker (Eisenberg, 1994). Eisenberg states that "The liquid product is typically water-clear at room temperature, with just a hint of paraffinic odor." He further states "The synthetic refinery feedstock produced by the AGC-21 process is free of most of the impurities found in conventional crude oil. It is totally free of sulfur, nitrogen, nickel, vanadium, asphaltenes, multi-ring aromatics, and salt. To a modern refinery or petrochemical complex, it

offers a wide range of product options, including premium quality diesel and jet fuel, specialties such as lube oils and waxes, and chemicals for the manufacture of solvents, alcohols, and polymers. As gas conversion liquids become readily available, they are sure to provide new product opportunities in response to ever increasing environmental challenges and market demands."

Exxon has invested over $150 million to date on development of this process in recent years. Pilot plant run lengths of 2 to 3 months of round-the-clock operation were typical and throughput rates approached 200 BPD of product. Eisenberg states that the demonstration program has provided the information needed . for confident scale-up to design commercial facilities capable of producing 50,000 to 100,000 BPD or more of liquid product. Very little economic information is provided except that "Sizes will likely be in the 50 to 100 kB/D range, and total investment for a grass roots remote site may easily exceed two billion dollars." (Eisenberg, 1994).

3.3.2.1 Fischer-Tropsch Process. For the economic analysis in this study, a FT-type process was selected as the model GTL process because it has reached the early stages of commercialization, provides the best available data for estimating capital and operating costs, and exhibits the lowest cost structure of early plant development. This is in contrast to several other indirect and direct conversion processes, several of which are still at the bench scale R&D stage.

FT process development began with the work of Fischer and Tropsch in Germany in the 1920's. They reported synthesis of higher hydrocarbons from a synthesis gas (H_2 and CO) using a cobalt-based catalyst at atmospheric pressure. The FT process consists of three steps: (1) generation of synthesis gas, (2) the FT synthesis step, and (3) the separation and upgrading step as shown in **Figure 3.2**. The values below each step give the approximate percentage of the total cost for each step. The generation of synthesis gas can be achieved through several processes; a partial oxidation synthesis gas generation is represented in the scheme shown in **Figure 3.2**. Using methane, the partial oxidation process can produce a 2 to 1 H_2/CO ratio, synthesis gas product, which is near the ideal stoichiometry for FT synthesis.

Efforts to improve FT process economics have focused most recently in the synthesis gas generation part of the processes. This area represents 60% of the investment of the full FT process. One area of interest is autothermal reforming, which is a combination of partial oxidation and steam reforming (see **Figure 3.1**) that permits a decrease in maximum temperature and results in reduced oxygen consumption and cost (Rostrup-Nielson, 1994).
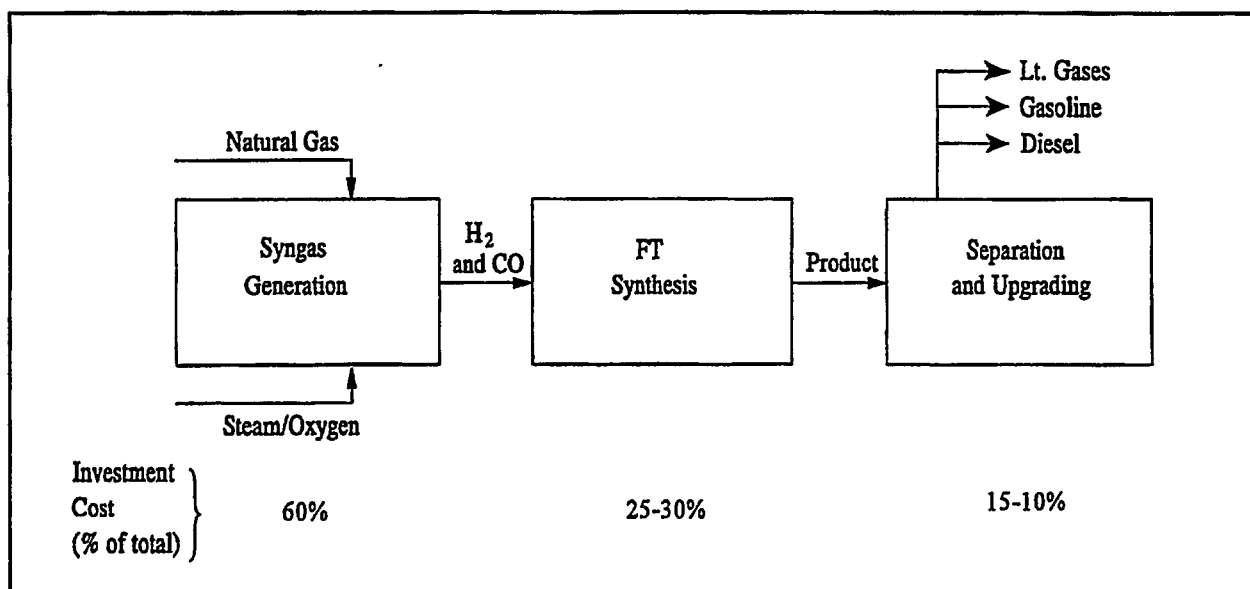
Figure 3.2. Fischer-Tropsch process schematic.

Another recent development by the Argonne National Laboratory and industry collaborators uses a mixed-ion conducting membrane for oxygen production from air, replacing the expensive cryogenic oxygen impact on the cost of synthesis gas generation (Balachandran, 1994). This concept of using a membrane to separate oxygen from air and then deliver the oxygen to react with the methane presents possibilities for reducing the cost by 25% or more for state-of-the-art synthesis gas production and subsequent FT products. Such process improvement is only in the development stage at this time; however, both DOE and the inventors have plans to step up the pace of cost-shared development of this technology. Although the mixed-ion membrane process is promising, it is premature to assume its availability for purposes of this ANS gas assessment.

The second step in the FT process is the FT synthesis step. The overall reaction for FT synthesis from CO and H_2 generates a range of paraffin, olefin, and oxygenated products with the average molecular weight distribution determined by catalyst type, synthesis gas H_2/CO ratio, and operating temperature and pressure. The range of products from the FT synthesis is illustrated in **Figure 3.3** and shown in detail in **Table 3.1** (Mills, 1994). These data are for SASOL's two Fischer-Tropsch, coal-based, 50,000 to 65,000 BPD plants and its newer, gas-based, 60,000 to 75,000 BPD plant at Mossel Bay, South Africa. These plants use an iron-based catalyst and have product distributions that are consistent with a 0.75 Schultz-Flory parameter (α), where α is the probability of chain growth, as illustrated in **Figure 3.3** (Tijm, 1993).

Table 3.1. Dimensions and product selectivities of SASOL commercial reactors (from Mills, 1994).

| Reactor Type	SASOL I		SASOL II
Operating Conditions	Arge (Fixed Bed)	Synthol (Circ. Fluid Bed)	Synthol (Fixed Fluid Bed)
Catalyst, alkali promoted Fe	Precipitated	Fused	Fused
Catalyst circulation rate, MgH	0	8000	--
T (°C)	220 - 225	315	320
P (MPa)	2.5 - 2.6	2.3 - 2.4	2.2
Fresh feed H_2 - CO (mol)	1.75 - 2.5	2.0 - 3.0	--
Recycle ratio (mol)	1.5 - 2.5	2.0 - 3.0	--
H_2 + CO conversion (mol%)	60 - 68	79 - 85	--
Fresh feed ($km^3 h^{-1}$)	20 - 28	70 - 125	300 - 350
Diameter x height (m)	3 x 17	2.2 x 36	3 x 75
Product Selectivity (wt%)			
C_1	5.0	10.0	11.0
$C_{2=a}$	0.2	4.0	
C_2	2.4	6.0	7.5
$C_{3=a}$	2.0	12.0	
C_3	2.8	2.0	13.0
$C_{4=a}$	3.0	8.0	
C_4	2.2	1.0	11.0
C_5 - C_{12} (gasoline range)	22.5	39.0	37.0 (C_5 - 191°C)
C_{13} - C_{18} (diesel range)	15.0	5.0	11.0 (191 - 399°C)
C_{19} - C_{21}	6.0	1.0	3.0 (399 - 521°C)
C_{22} - C_{30}	17.0	3.0	
C_{30}	18.0	2.0	0.05 (>521 ° C)
Non-acid chemicals	3.5	6.0	6.0
Acids	0.4	1.0	--
=a - Indicates olefin.			
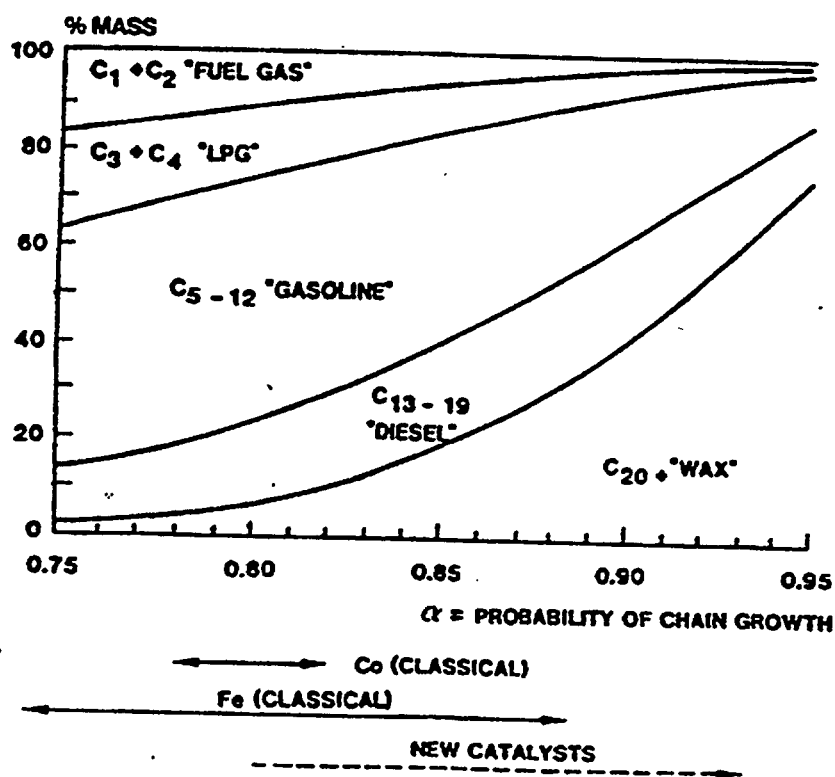
Figure 3.3. Molecular mass dstribution in raw product (Tijm, 1993).

The newer Shell Middle Distillate Synthesis (SMDS) plant in Bintulu, Malaysia, employs a different FT process approach. The plant is designed to produce 12,000 BPD of liquids from 100 MMCFPD of natural gas (Tijm, 1993). The overall design thermal efficiency of the plant is 63%, compared to a theoretical maximum of 78% for conversion of methane into paraffins (Eilers, 1990). The Shell SMDS process uses a new cobalt-based catalyst in a fixed bed reactor that operates at lower temperatures than the iron-based catalyst used in the SASOL plants, and produces low yields of light gas and high-yields of heavier paraffin wax product.

The final step in the FT process is upgrading of the FT liquid product by conventional refining processes. Lighter gases can be isomerized, naphtha can be reformed, and diesel material prepared for blending. The heavy (C_{19+}) wax material can be cracked in a fluid cracking unit or a hydrocracker. The Shell process uses hydrocracking because the desired product is diesel fuel. Hydrocracking has the selectivity capability to produce a narrow boiling range product, most of which will be in the diesel boiling range. The products of the Shell SMDS process are pure paraffins, free from impurities such as nitrogen and sulfur and from aromatic species. Hence, the products have a low environmental impact upon combustion, which makes them ideal for blending with gasoline or diesel from normal petroleum refining for upgrading the

products to meet newer emission standards (Eilers, 1990).

Shell's published information states that the specific capital cost of a 10,000 BPD plant built on a developed site in an industrialized country would be around $30,000 per daily barrel liquid (DBL), where a similar plant in a remote, undeveloped location, could cost up to double that amount. On the other hand, larger plants in the 25,000 to 60,000 BPD range might only be $25,000 to $30,000/DBL in a remote area because of economics of scale (Tijm, 1993).

For this evaluation, the primary source of economic data for the FT case was a Bechtel study that evaluated the economics of direct conversion processes (Fox, 1990). Bechtel has done many economic studies of FT but generally with coal as feedstock rather that natural gas. The Bechtel study (Fox, 1990) focused on a modest-scale plant of 14,500 barrels per stream day (B/SD). The thermal efficiency of the overall facility was about 55%. A detailed material balance was not provided but a selectivity to C_5 and heavier compounds of 84% was assumed and operating conditions and yield were based on Gulf-Badger data (Singleton, 1988). Referring to **Figure 3.3**, this would mean the yield would be at an α (Schultz-Flory parameter) of approximately 0.86 with relatively low light-gas yields and intermediate yields of diesel and heavier C_{20+} yields. The subsequent economic study by Hackworth (DOE, 1995) indicates that later work has shown that improvement in the Bechtel case could be achieved by use of different reactors (such as slurry reactors), catalysts, and potentially with an improved synthesis gas production process.

The results described above, support an assumption that an overall conversion efficiency of 60% is achievable with current state-of-the-art technology for 40, 000 to 50,000 BPD, Fischer-Tropsch GTL plants.

3.3.3 Pyrolysis Gas Conversion Processes

Natural gas can be pyrolyzed to acetylene (C_2H_2), which in turn can be converted to liquid fuels by catalytic processes similar to the synthesis gas approach. Acetylene can also be used as a building block for the synthesis of commercially important compounds such as vinyl chloride, vinyl acetate, butadiene, and neoprene. Acetylene production by pyrolysis of natural gas is based on the fact that the free energy of formation of acetylene decreases with increasing temperature, which is the opposite of other hydrocarbons (EPRI, 1982). At temperatures above 1600 K, the most stable species in a hydrocarbon mixture is acetylene; it is even more stable than its component elements.

Pyrolysis is achieved using an electric plasma arc to dissociate methane to carbon and hydrogen which are then quenched to form acetylene and other by-products. Acetylene is then oligomerized to liquid hydrocarbon products. Methane pyrolysis has been practiced in the past with varying degrees of success (EPRI, 1982; Gladisch, 1962). The only significant gas conversion application of pyrolysis technology is at a BASF plant producing acetylene in Germany (Gold, 1978). Begun in 1925, the plant and process were expanded and modified by Huels in 1939 to produce 100,000 tons per year (t/y) of acetylene for production of synthetic rubber (Gladisch, 1962). Today the plant produces acetylene, ethylene, hydrogen, and carbon black for chemicals production and synthetic rubber. The Huels plant uses 19 plasma arc reactors operated at 8.3 MW each. A mixture of C_1 to C_4 hydrocarbons is fed into the arc region of the reactor. Downstream, hydrocarbon liquids are used to quench the hot reaction gases, followed by further quenching with a water spray.

The major drawback to pyrolysis conversion has been the inability to raise the temperature of the natural gas feed stream very rapidly and to quench the products to a non-reacting mixture quickly enough to avoid the formation of non-selective by-products via secondary reactions. Historically, direct quench and direct reactive quench using liquefied petroleum gas pyrolysis has been studied in this regard (EPRI, 1982).

Recently, an aerodynamic quench using a converging-diverging nozzle has been demonstrated at the DOE's Idaho National Engineering Laboratory (INEL) to provide quenching in a very short residence time, under 2 milliseconds (Detering, 1995). Perfect conversion would yield 3 moles of hydrogen for each mole of acetylene produced ($2C_1H_4 \rightarrow C_2H_2 + 3H_2$). Acetylene yields above 90% of the theoretical yield have been achieved in the INEL research; the balance is made up of very small amounts of carbon and unreacted methane. After the reaction and quench, acetylene can be hydrogenated to ethylene and then oligomerized to gasoline, diesel, or fuel-oil hydrocarbons. Except for recycle and hydrogenation requirements, the hydrogen would be available for other uses, including generating electricity needed to power the plasma reactor. The plasma quench process is illustrated in **Figure 3.4**.

The plasma quench process under development by INEL and industrial collaborators advances the plasma arc technology developed by Huels for acetylene production. In the plasma quench process, hydrogen gas is heated by an electric plasma arc and natural gas feed material is injected into the hot plasma jet for conversion into acetylene. The electric power requirements for the plasma quench process at the pre-pilot scale are about 6 kW-hr/kg C_2H_2 compared to the Huels process requirements of 11 kW-hr/kg C_2H_2. Preliminary economic analysis results indicate that the plasma quench process costs could be comparable
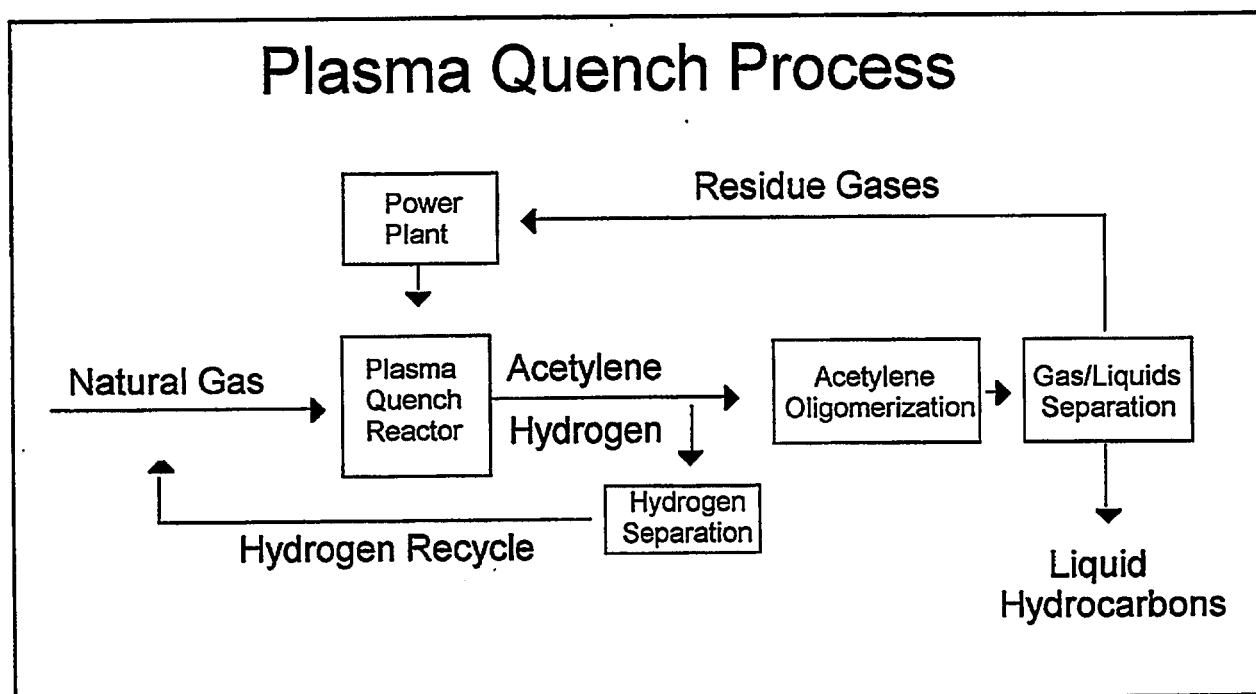
Plasma Quench Process

Figure 3.4. Schematic of the Plasma Quench Process for conversion of natural gas to liquid fuels.

to those of conventional FT processes for production of liquid fuels from natural gas (Detering, 1995). However, as is the case with the prospective ceramic membrane advance in FT technology, the rapid quench advancement is still in the bench scale development stage and is not used in the evaluation.

3.3.4 LNG Liquefaction and Transportation

Where gas pipeline connection from the source directly to the market is impractical or uneconomic, the utilization of low-cost natural gas by liquefaction to LNG and transport to distant gas markets is well established. The LNG process involves the physical conversion of natural hydrocarbon gas to a low-pressure cryogenic liquid at -160°C at an LNG facility for transport to market in specially designed cryogenic marine tankers. LNG is then revaporized to the gaseous state for use in the gas market.

A LNG liquefaction plant employs a low-temperature refrigeration cycle, typically a multi-train plant of about 6,600 tons per day/train capacity (Fox, 1988) to chill and liquefy the natural gas. Feed pretreatment and refrigerant component recovery sections are normally a part of the plant facility. The LNG plant is usually located at or near a marine tanker loading terminal and natural gas is transported via gas pipeline from the gas field to the plant. LNG storage capacity is required at the loading terminal to accommodate tanker loading. The LNG marine tankers either consume boiloff gas as fuel or re-liquefy the gas and burn

diesel oil as fuel. A typical LNG marine tanker has a capacity of about 125,000 cubic meters.

Published information on costs of LNG plants and tankers provide a cost range estimate from about $1.3 to 2.2 million/MCFPD for plants and about $250 million per LNG tanker (Cornot-Gandolphe, 1995; Hawkshaw, 1995). The cost data available for the TAGS project indicates a plant cost of about $1.2 million/MCFD and a tanker cost of about $240 million/tanker (Alaska Conservation Foundation, 1994; FERC, 1995).

3.4 Summary

The utilization of the ANS natural gas resource requires the transportation of that gas from the North Slope to existing markets in the Lower 48 or to overseas markets. Such a transportation system does not currently exist although several options are being considered. The two potential options seen to be feasible are a gas pipeline/LNG project and a GTL conversion process that uses an existing oil pipeline to transport the resulting liquids. The LNG process converts natural gas to a low-pressure cryogenic liquid in a refrigeration cycle for transport in special LNG tankers. The GTL process (assumed for this study) converts natural gas to stable hydrocarbon liquid fuels through the synthesis gas/FT process and then to hydrocarbon fuels by catalytic processes.

Commercial-scale GTL conversion projects do exist but are few in number and inadequate for state-of-the-art GTL conversion economic viability to be considered well established. However, GTL conversion technology is rapidly developing and could result in significant improvement in conversion economics over those of existing plants. Likewise, GTL operation economics will benefit from the sophisticated infrastructure and high level of experience in arctic construction and operations that exist on the North Slope. It will also benefit from the envisioned larger plant sizes than that of the current FT gas conversion demonstration plant in Malaysia. Liquid fuels from the conversion of natural gas have a large existing market. Gasoline/diesel range hydrocarbon liquids with excellent environmental characteristics that can be produced from a GTL conversion process receive a premium price in world oil markets (see Section 4.1).

Of the various types of conversion processes, the Fischer-Tropsch indirect conversion process is the most established existing process although conversion costs remain high. The FT process first produces a synthesis gas from partial oxidation of methane followed by a catalytic process to convert the synthesis gas to liquid hydrocarbons that can be upgraded by conventional refining processes to gasoline, diesel fuel, or

both. A hybrid of partial oxidation and steam reforming and recently developed ceramic membrane oxygen production technologies both may offer significant conversion cost reductions for FT processes. Likewise, methane pyrolysis to yield acetylene which is then synthesized to hydrocarbon liquid products also holds promise for less expensive GTL conversion. Research is expanding the FT, pyrolysis, and other GTL conversion technology base and there is good reason to expect conversion costs will be less in the years ahead.

In comparison, LNG projects and technology are well established worldwide and a significant LNG market already exists, although competition in that market is significant. An ANS gas pipeline/LNG project will require a very sizable investment (over $6 billion in 1995$) for a trans-Alaska gas pipeline to transport the gas to a seaport that is not ice bound during winter months, and will have to compete in the worldwide LNG market with other proposed LNG projects, which do not require as large an initial investment for a gas pipeline connecting the gas source to the LNG facilities. The LNG project option would have the advantages that the shipping distance from Valdez to Japan is less than the shipping distances to market of most of the other projects, and its gas is a secure U.S. resource. Although large LNG markets exist in Pacific Rim countries, LNG prices have not been strong enough to date to support an ANS LNG project. Extensive efforts by commercial interests continue to show improvements in project economics and studies indicate that a window of opportunity for a ANS LNG market could develop in the 2005 time frame (Oil Daily, 1995a).