3/2/07 PRESENTA -TION: GAS TO LIQUIDS

Gas to Liquids Meeting

March 2nd 2007 House Resources

Confirmed:

Dr. Godwin Chukwu, Ph.D., P.E.
Petroleum Development Laboratory
Institute of Northern Engineering
University of Alaska Fairbanks
(his presentation will probably take one hour)

Cathy Foerster, Commissioner
Alaska Oil and Gas Conservation Commission
(via teleconference for questions)

Kevin Banks, Acting Director, Division of Oil and Gas
Alaska Department of Natural Resources
(via teleconference for questions)

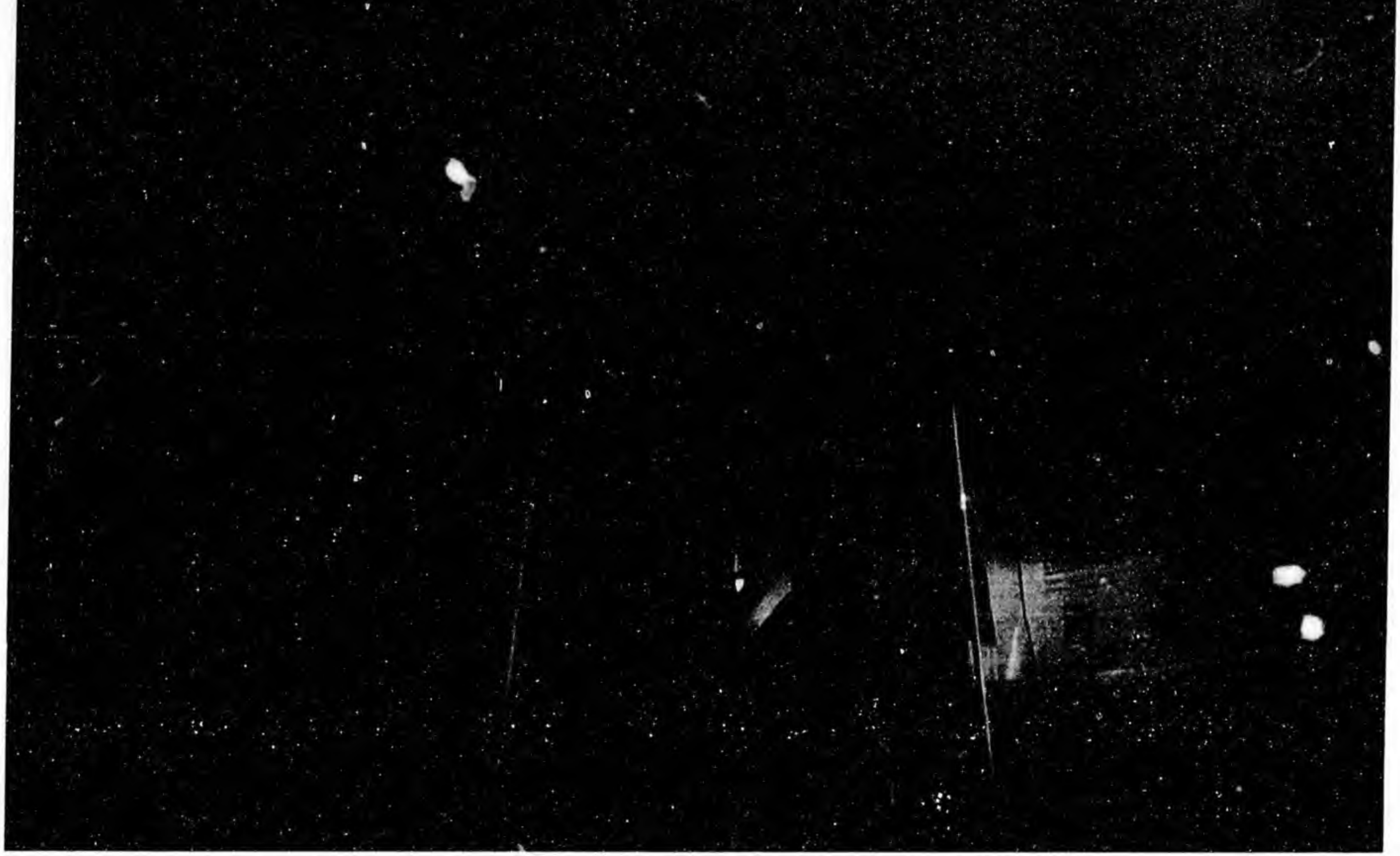
BP - Mike Gradassi, Project Development Manager for BP's Conversion Technology Centre
(brief presentation, probably ten minutes)

SasolChevron – Peter Cook (Sasol London)
(presentation for about half an hour)

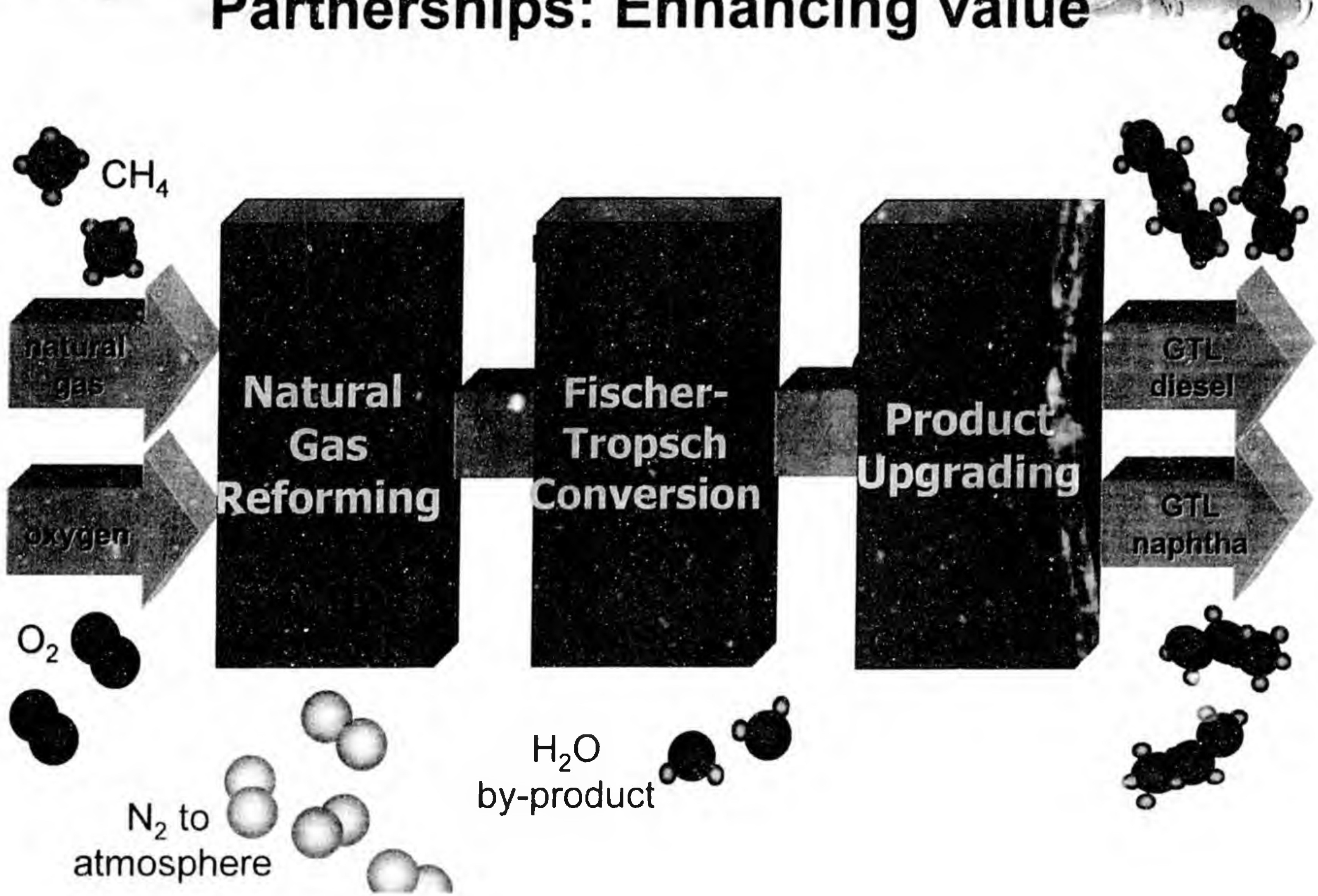
Invited:

Shell - Cam Toohey
Exxon - Kevin Jardell
Conoco Phillips – Michael Hurley, Gerry Gallagher
Flint Hills – Bob Evans, Jeff Cook
PetroStar – Royce Weller, Jerry Mackey, Doug Chapados
Alyeska – Mike Heatwole
AOGA – Kara Moriarty, Judy Brady
American Petroleum Institute-Peter Lidiak (pipeline specialist)
(probably most will be in the audience)

Sasol Chevron and GTL – an overview



Partnerships: Enhancing value



Sasol Chevron

Matching the GTL challenge

Global Drive For Cleaner Fuels	+	Monetise Abundant Global Gas Reserves
sasol *reaching new frontiers*		Chevron
Proven GTL Technology Operating Experience GTL Marketing Experience	Sasol Chevron	International Presence Marketing Expertise E&P Experience International Deal Making

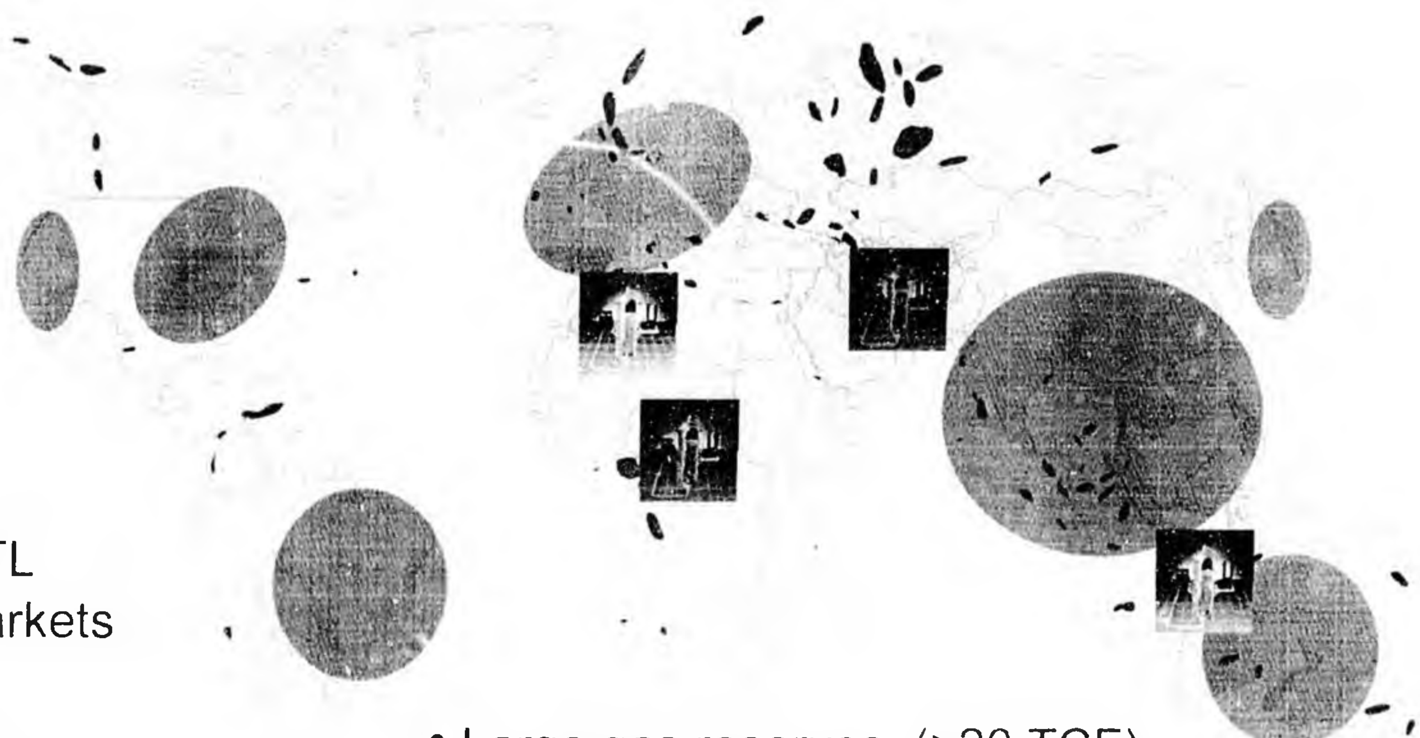
↓

Build, Own & Operate Plants - Market GTL Products

GTL PRODUCTS – COMBINING HIGH PERFORMANCE WITH LOWER ENVIRONMENTAL IMPACTS

Sasol Chevron

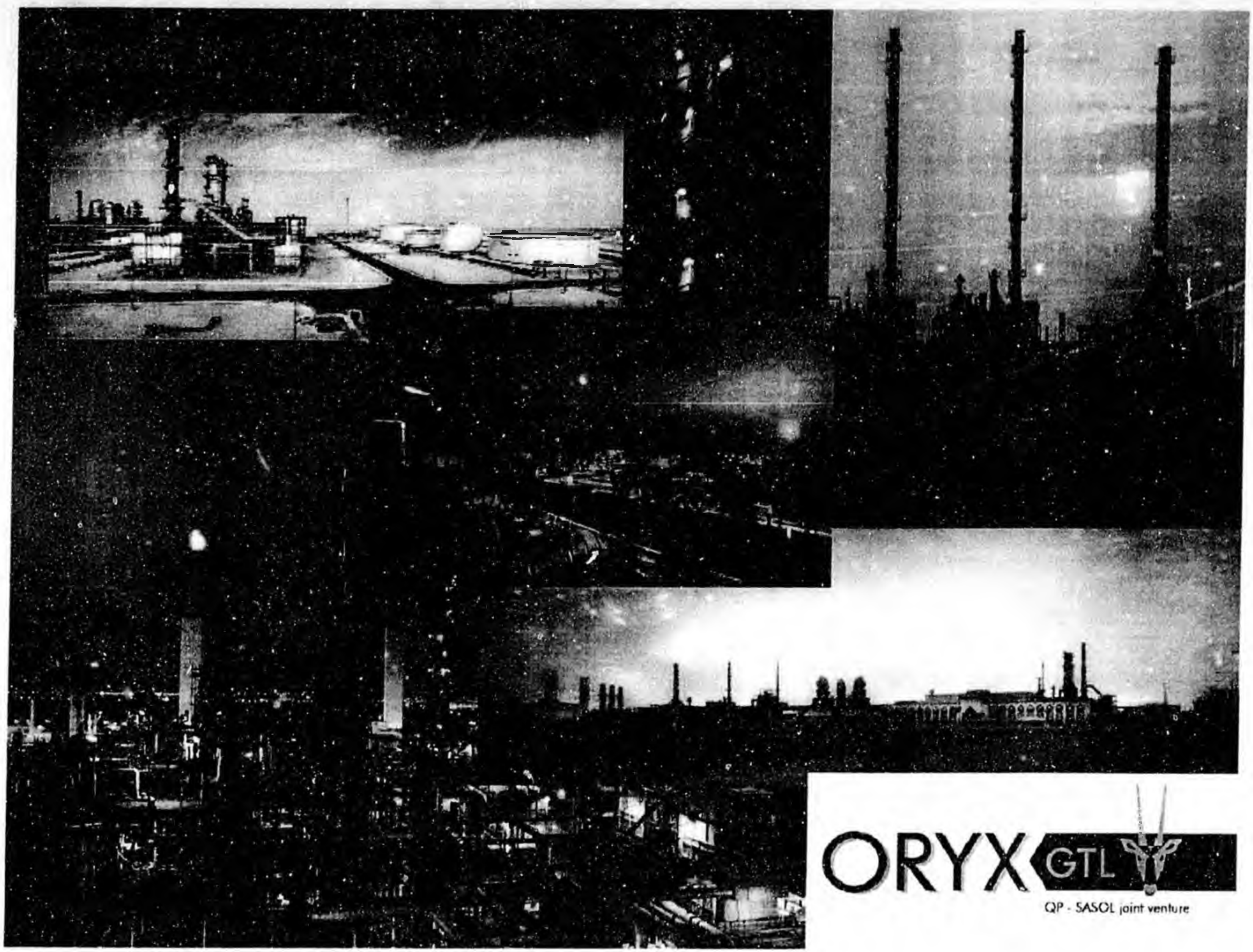
Locations for GTL



GTL Markets

Gas Reserves

- Large gas reserves (>20 TCF)
- Economic gas feedstock
- Access to the open ocean

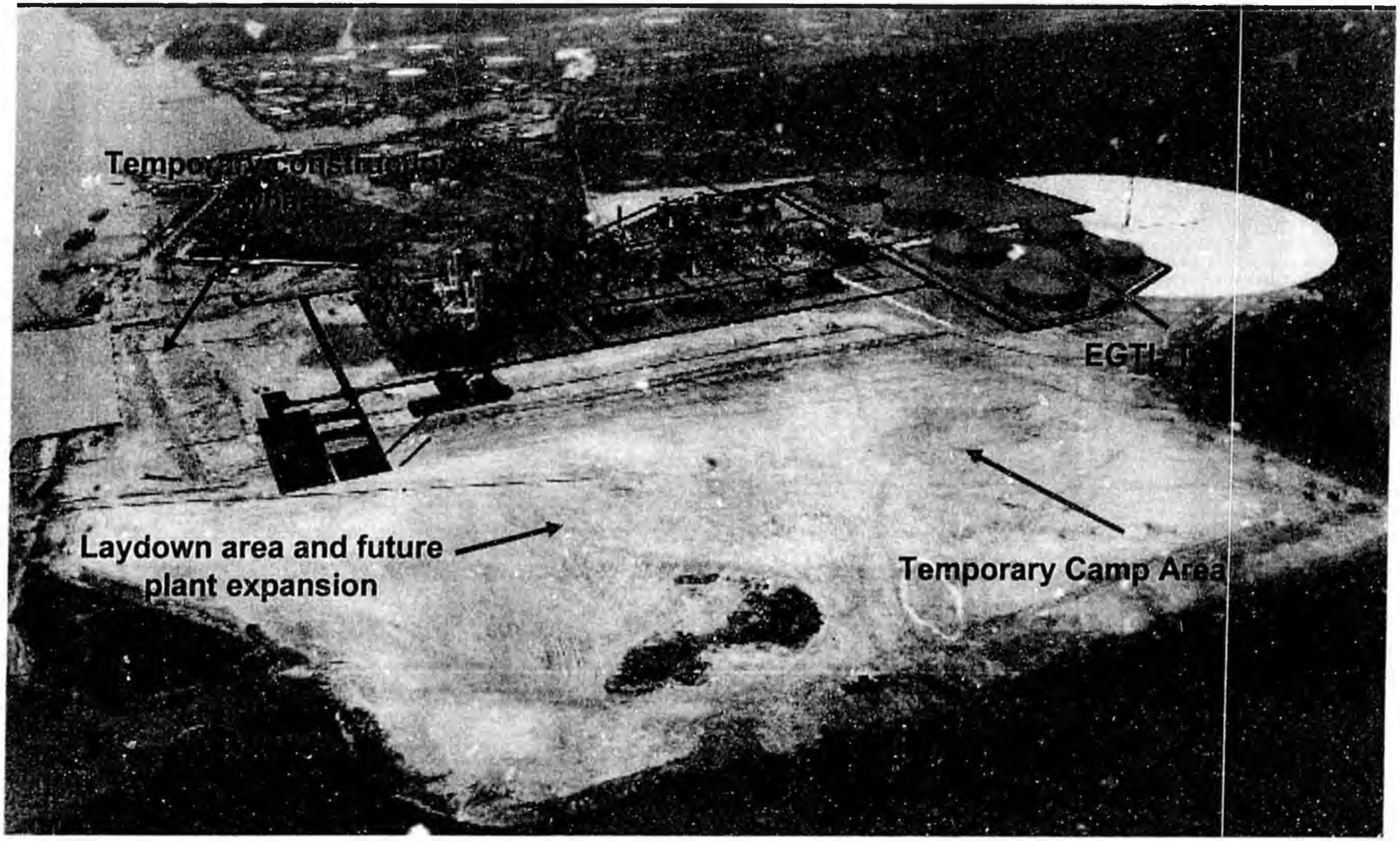


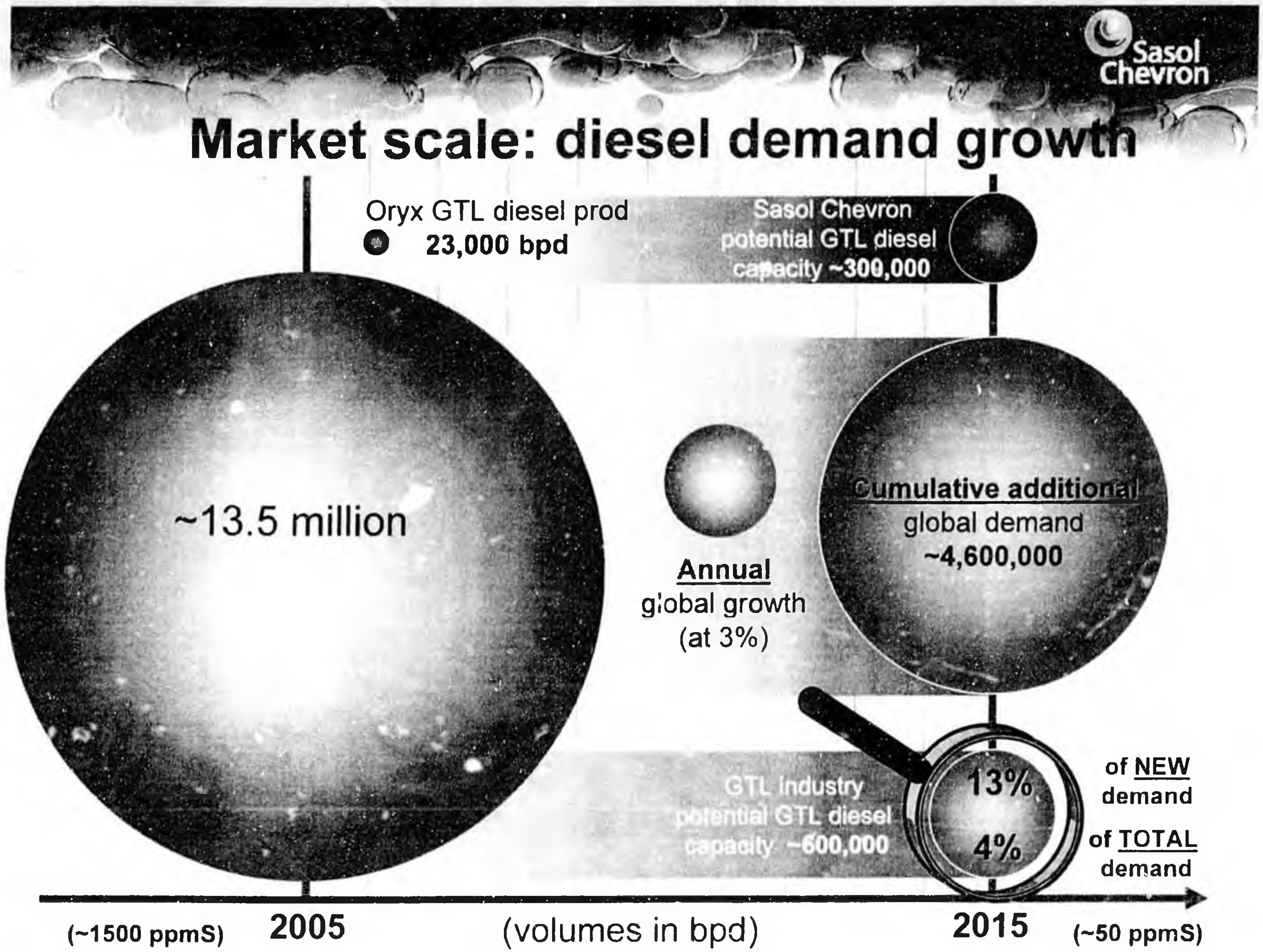
ORYX GTL

QP - SASOL joint venture

Sasol Chevron

EGTL – Escravos, Nigeria





Sasol Chevron
Market scale: diesel demand growth
Oryx GTL diesel prod
23,000 bpd
Sasol Chevron potential GTL diesel capacity ~300,000
~13.5 million
Annual global growth (at 3%)
Cumulative additional global demand ~4,600,000
GTL industry potential GTL diesel capacity ~600,000
13%
4%
of NEW demand
of TOTAL demand
(~1500 ppmS)
2005
(volumes in bpd)
2015
(~50 ppmS)

GTL diesel market channels

Crude oil

Conventional Refining

Market-compliant diesel

Regular

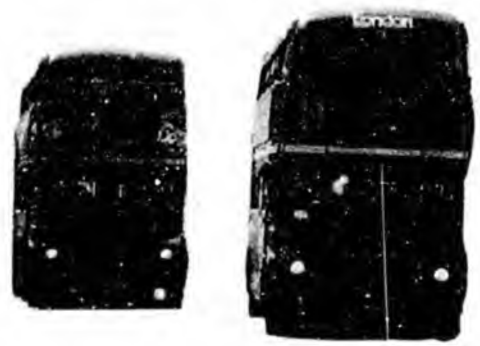
Blendstock

Premium

Short term

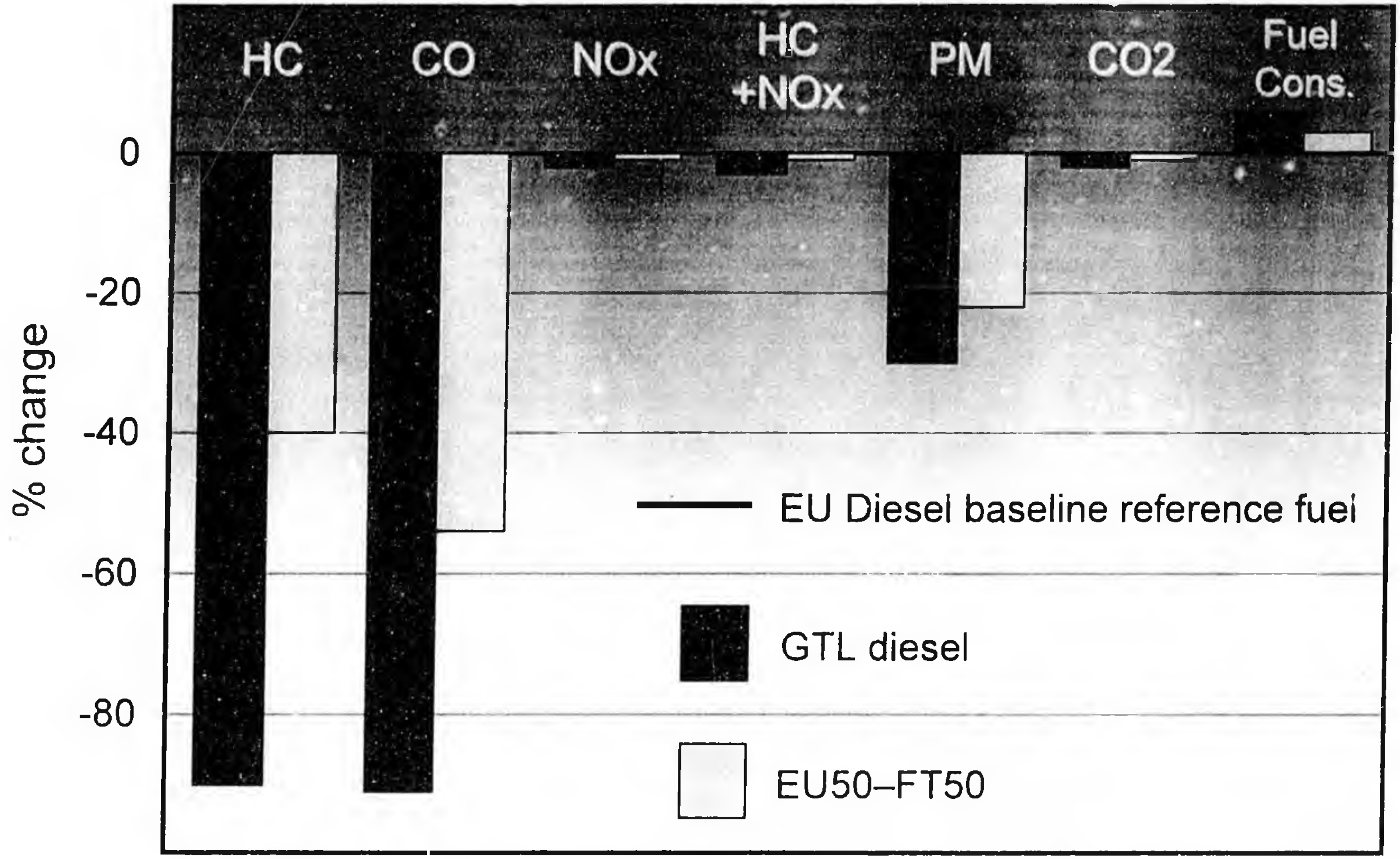
Neat Applications

Longer term

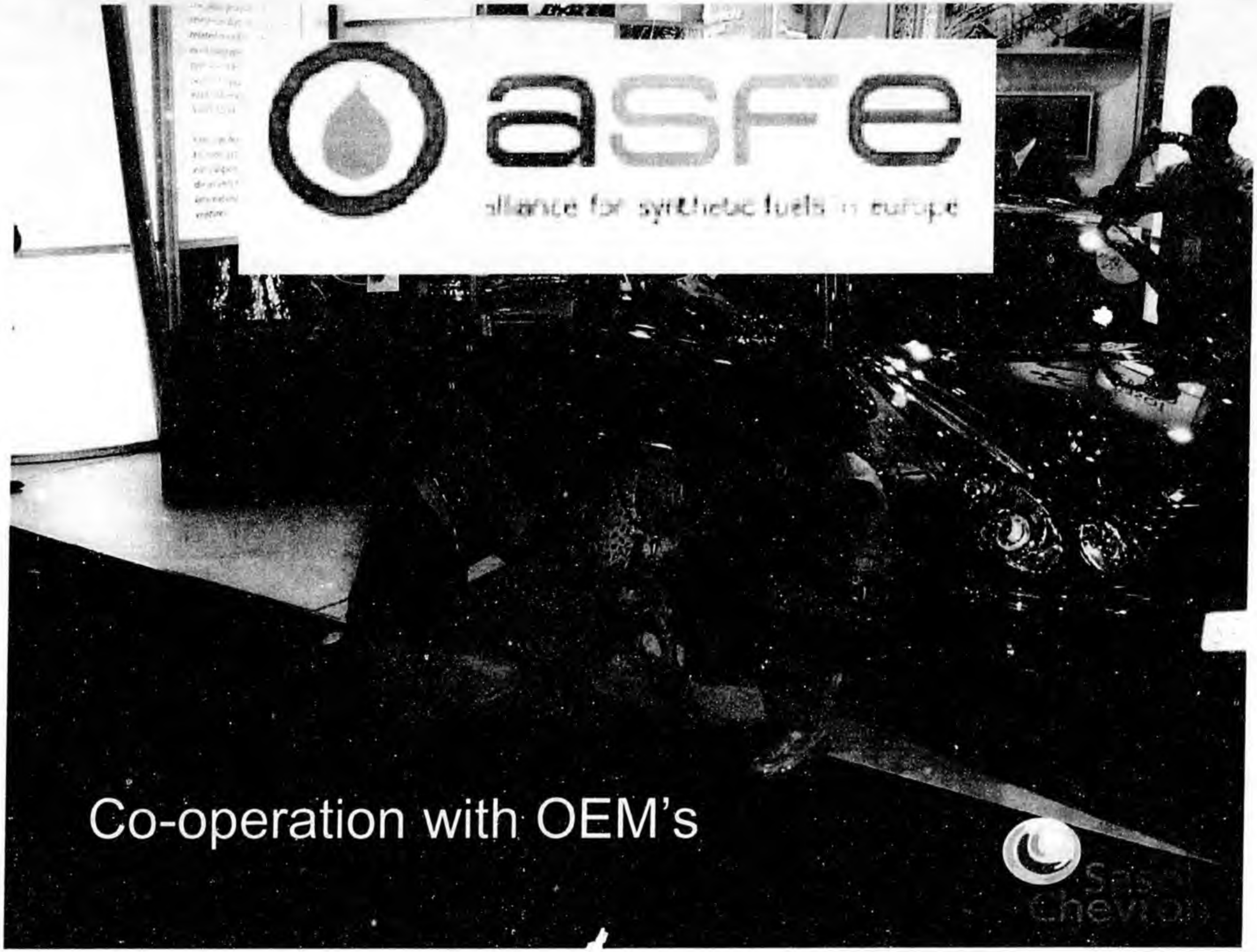


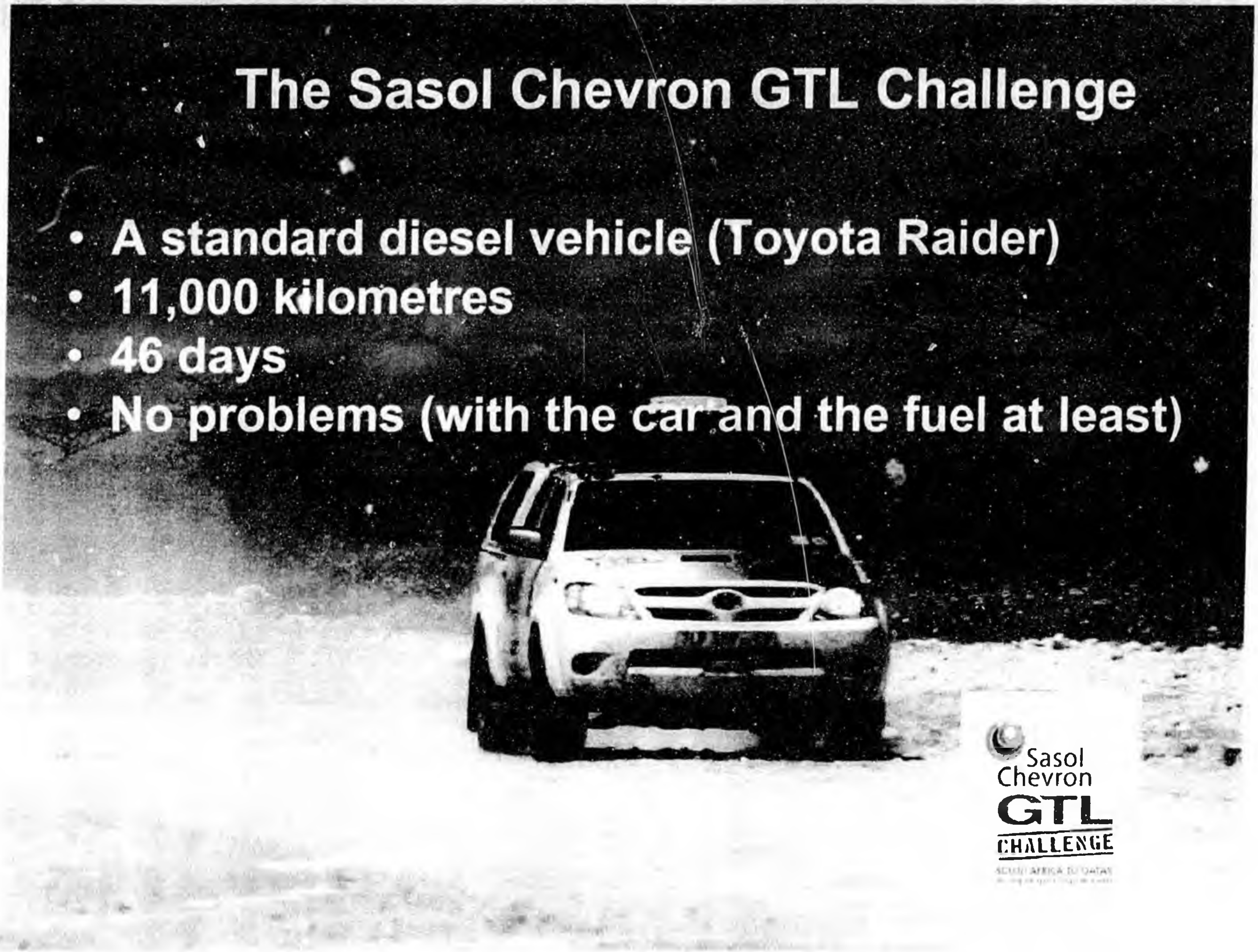
Maximum performance and emission benefit

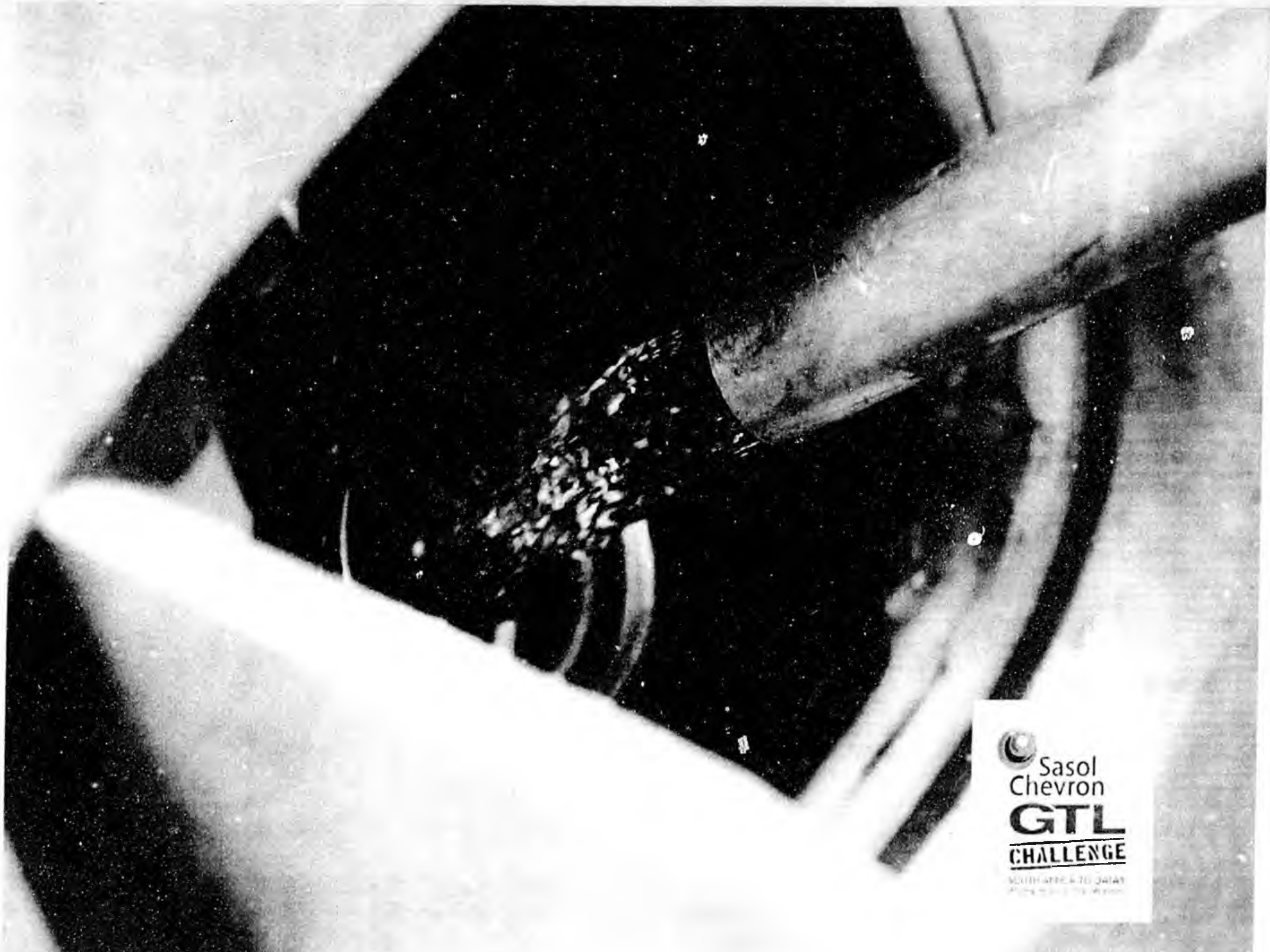
Meeting new air quality demands



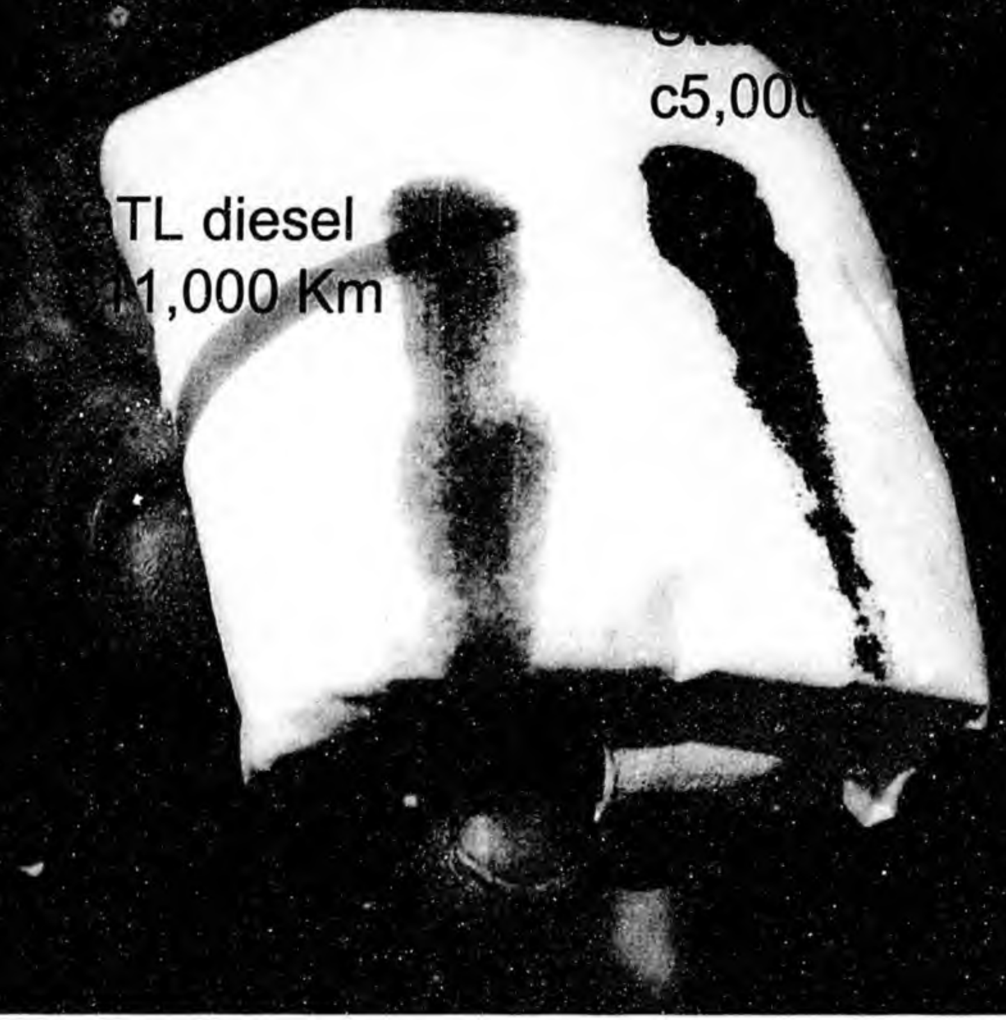
Results from passenger engine trials with Daimler Chrysler


asfe
alliance for synthetic fuels in europe
Co-operation with OEM's
Sasol Chevron

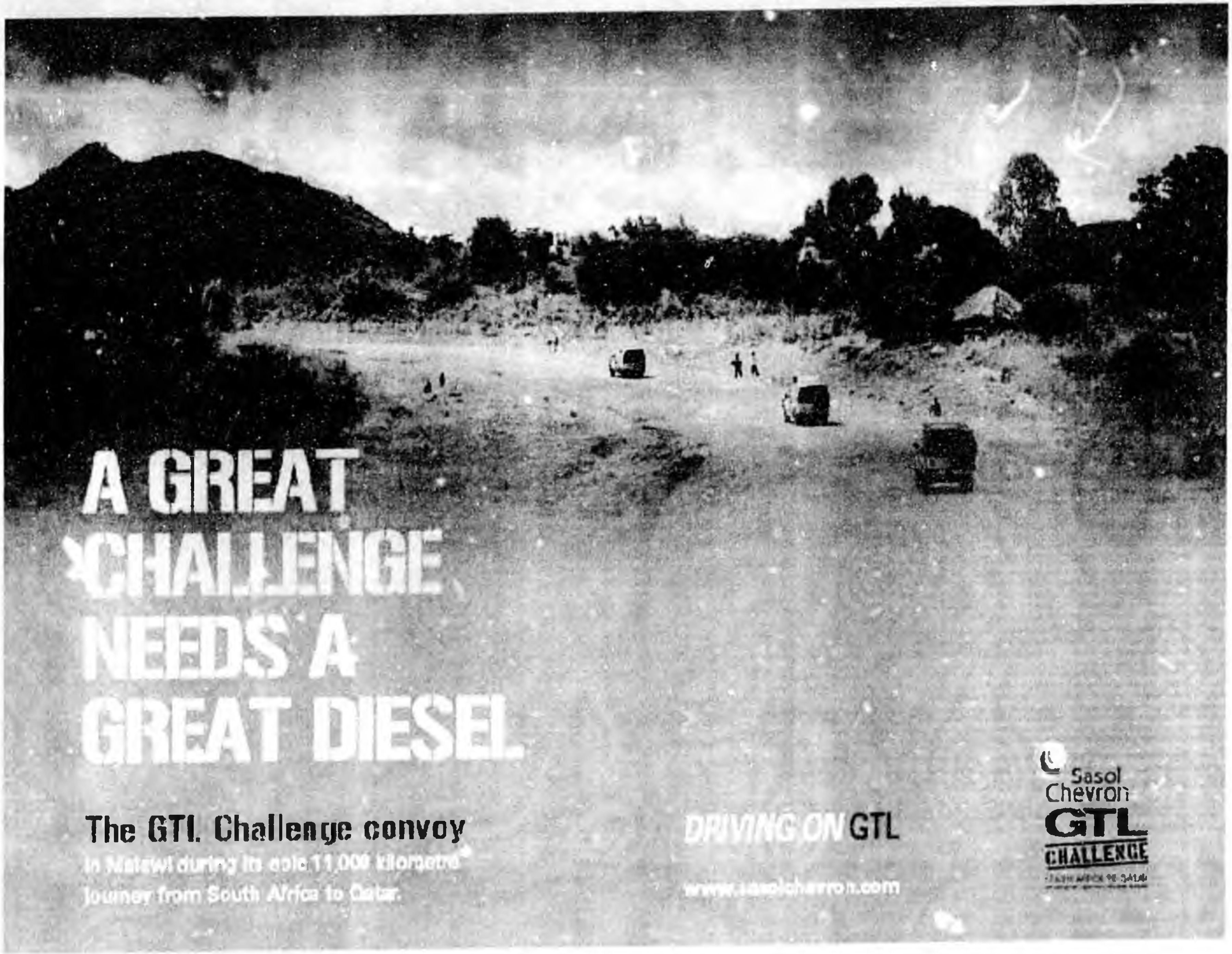

The Sasol Chevron GTL Challenge
• A standard diesel vehicle (Toyota Raider)
• 11,000 kilometres
• 46 days
• No problems (with the car and the fuel at least)
Sasol Chevron GTL CHALLENGE


Sasol
Chevron
GTL
CHALLENGE

Journey's End



Sasol Chevron GTL CHALLENGE


A GREAT CHALLENGE NEEDS A GREAT DIESEL
The GTL Challenge convoy
in Malawi during its epic 11,000 kilometre journey from South Africa to Qatar.
DRIVING ON GTL
www.sasolchevron.com
Sasol Chevron
GTL
CHALLENGE

OPERATIONAL ISSUES IN GAS-TO-LIQUID (GTL)

TRANSPORTATION THROUGH

THE TRANS ALASKA PIPELINE SYSTEM (TAPS)

Presented to the Alaska State Legislature

(House Resources Committee)

March 2, 2007

Godwin A. Chukwu (PhD, PE)
Professor of Petroleum Engineering
Department of Petroleum Engineering
University of Alaska Fairbanks

OUTLINE

- ANS Gas Resources
- ANS Gas Utilization Options
- Problem Statement
- Possible Solution
- Gas to Liquid Technology
- Features of TAPS

OUTLINE (Cont'd)

- Project Focus
- Proposed Modes of GTL Transportation through TAPS
- GTL Transportation Issues
- Operational Challenges
- Conclusions

ANS GAS RESOURCES

- **Proven and Recoverable Conventional Natural Gas Reserves: 38+ TCF**
  - **Prudhoe Bay (29+ TCF)**
  - **Point Thompson (9+ TCF)**
- **Other Potential Resources:**
  - **Conventional Gas in ANWR (31 TCF)**
  - **ANS Gas Hydrates (590 TCF)**
  - **Coal – Bed Methane (1000+ TCF)**

ANS GAS UTILIZATION OPTIONS

- Transportation through a Newly Constructed Trans-Alaska Gas pipeline
- Conversion to miscible injectant (MI) for Enhanced Oil Recovery (EOR) operations on the north slope
- Build Natural Gas based petrochemical complex
- For Electrical Power generation
- Burning Natural Gas to Generate Steam for potential Thermal Recovery Options
- Chemical Conversion to GTL products and transport through TAPS

PROBLEM STATEMENT

- Dwindling oil production on Alaska North Slope (ANS) is exerting increased burden on economic operation of the TAPS
- How do we continue to operate the TAPS economically in the future
- What do we do with such vast gas resources?
- Domestic gas market far away from ANS
- Very small local demand
- Limited natural gas use in EOR and other operations

POSSIBLE SOLUTION

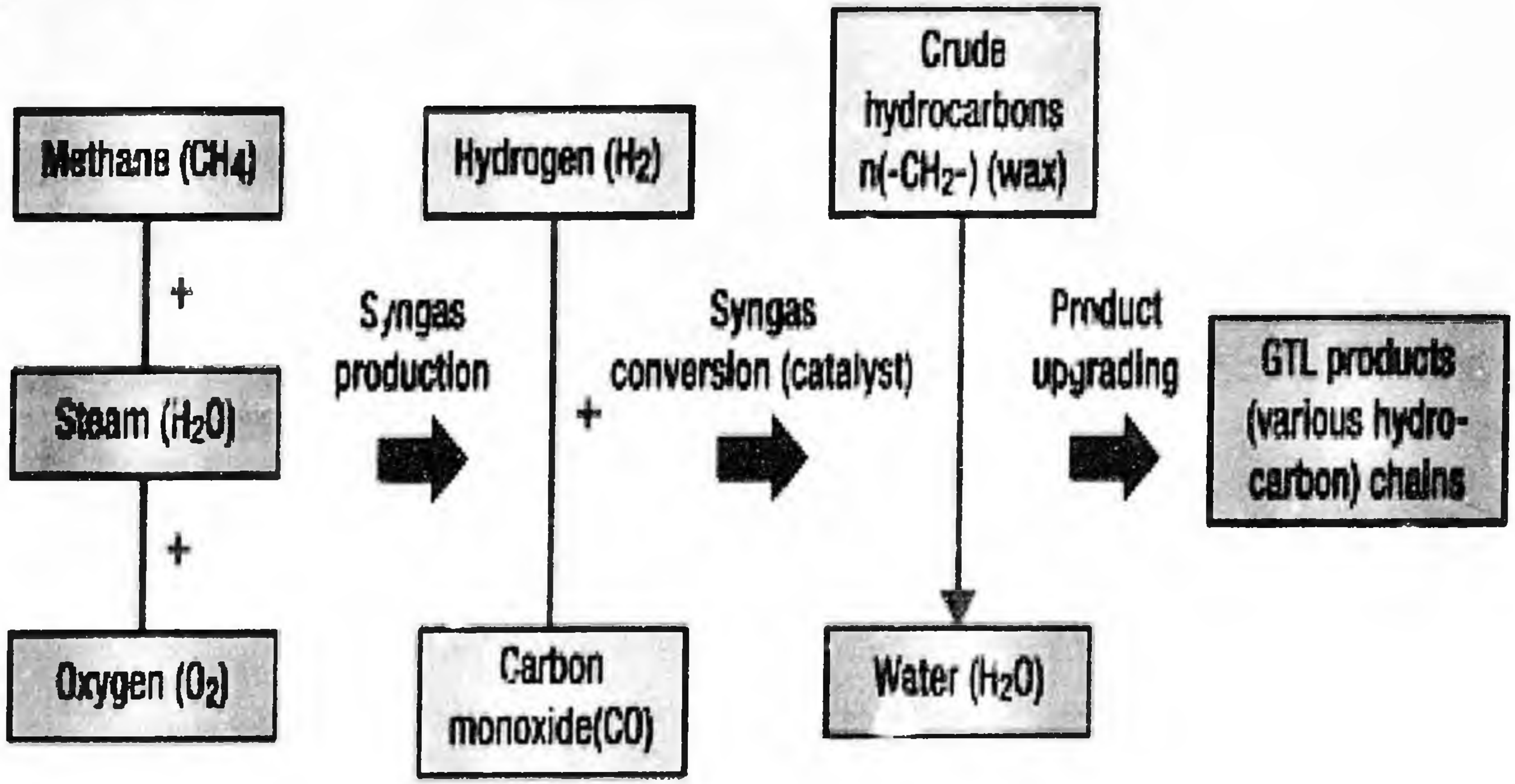
- A combination of the two part problem statement can lead to a feasible solution
- The vast natural gas resources on the ANS can be converted to Gas-to-Liquids (GTL) products using the Fischer-Tropsch (FT) process that dates back to WW II period
- These so called GTL products can be utilized to fill up the Trans Alaska Pipeline System (TAP) with crude oil
- In this manner we can address both the issues, i.e., increase the economic life of TAPS and monetize the huge gas resources on the ANS

GAS-TO-LIQUID (GTL) TECHNOLOGY

- 3-step Fisher-Tropsch chemical process for converting natural gas (CH_4) to synthetic crude

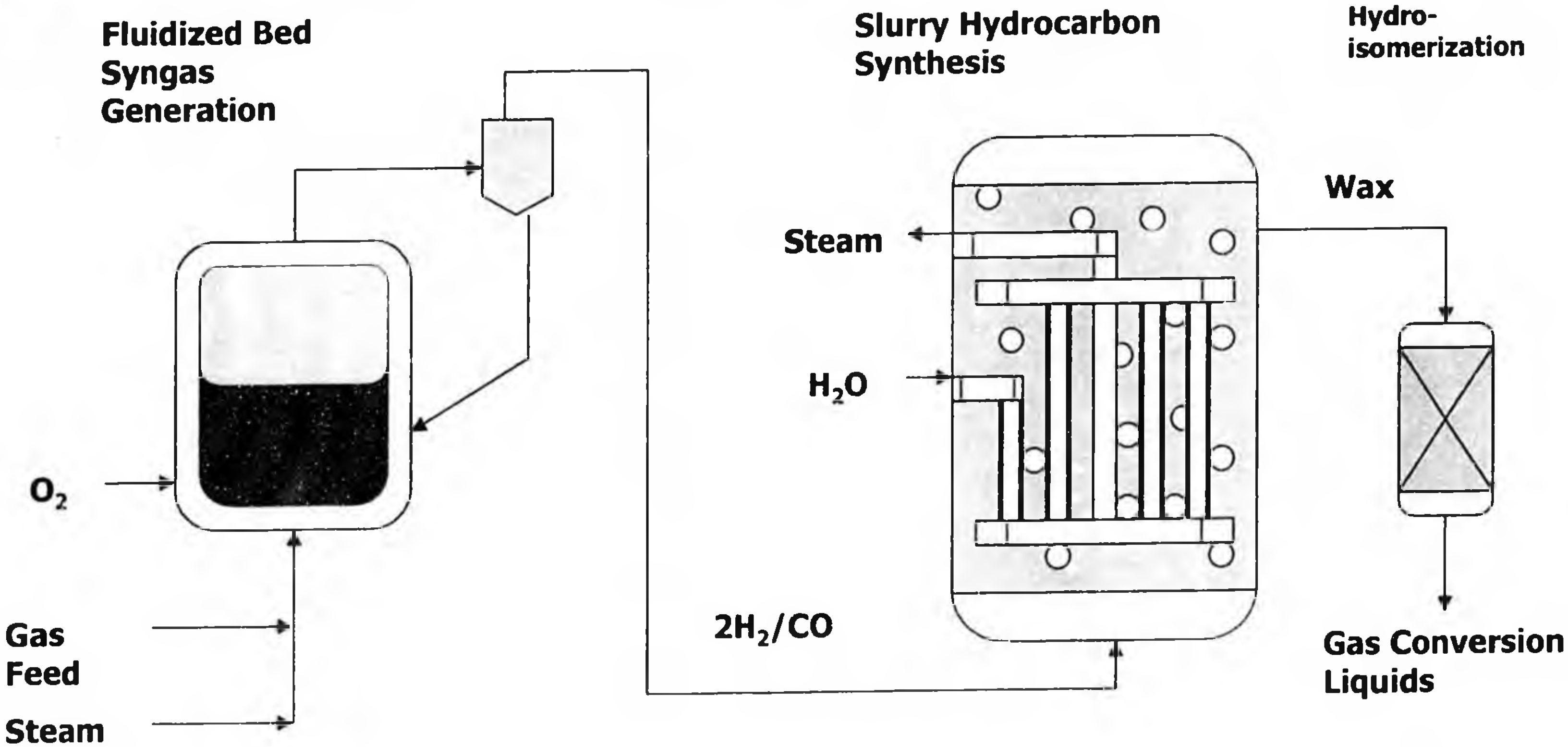
- Direct production of Diesel, Naphtha, Kerosene

GAS-TO-LIQUID (GTL) TECHNOLOGY (cont'd)



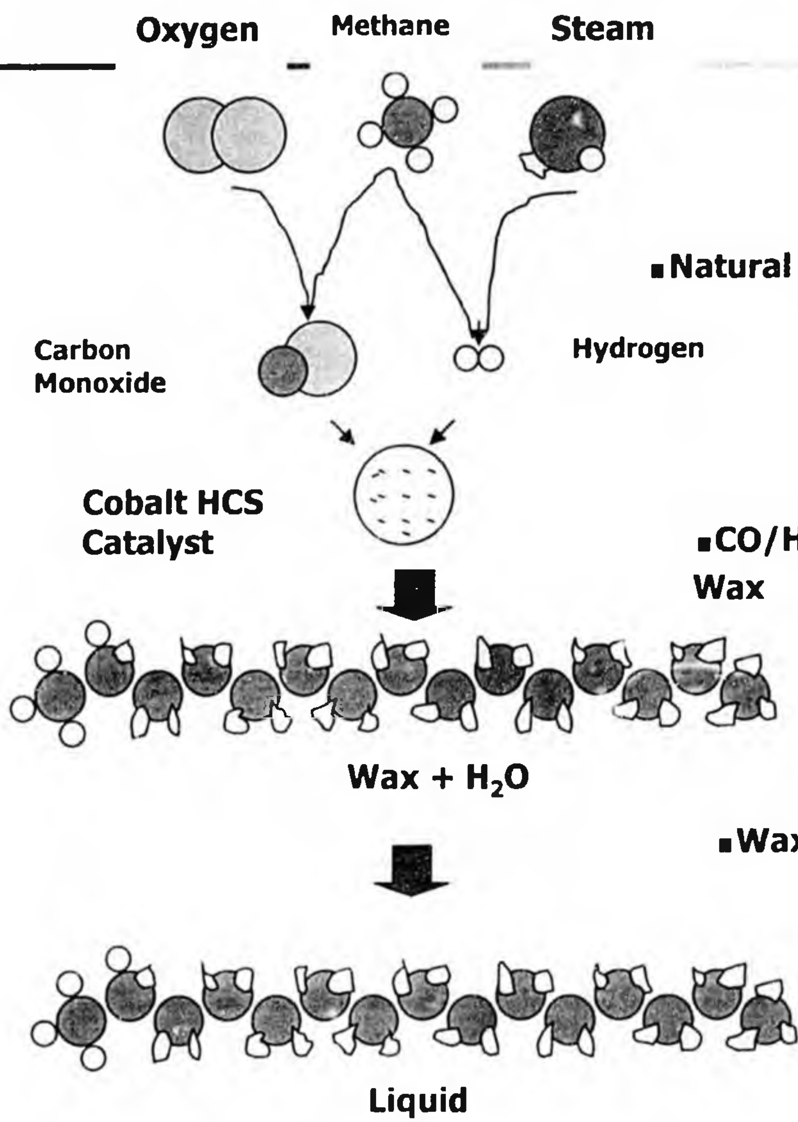
Courtesy: Fischer-Tropsch process for obtaining GTL products (Fischer, 2001)

GAS-TO-LIQUID (GTL)TECHNOLOGY (cont'd)



Courtesy: Exxon AGC-21 (Advanced Gas Conversion for the 21st Century), October, 1998

GAS-TO-LIQUID (GTL) TECHNOLOGY (cont'd)



- Natural Gas Reacts with O2/H2O
- CO/H2 Catalytically Synthesized To Wax
- Wax Isomerized To Liquids

Courtesy: Exxon Chemistry for producing AGC-21 Liquids (October 1998)

GTL TECHNOLOGY (cont'd)

- Why?
  - Significant worldwide volumes of stranded gas reserves
  - Diversify marketing options
  - Production of Environmentally Friendly Fuels
- Why now?
  - Technology advances have significant reduced capital costs
- Why Alaska?
  - No economic gas utilization option now
  - Investigate all potential options
  - Continued operation of TAPS will require significant increase in throughput

BENEFITS OF GAS-TO-LIQUID (GTL) PRODUCTS

- GTL is an attractive way to utilize ANS gas resources
- A "clean" source of energy
  - environmentally friendly
- Make use of existing TAPS infrastructure
- Work as diluent in future diverse throughput of ANS heavy oils
- GTL transport will increase TAPS throughput and economic operational life

FEATURES OF TAPS

- Existing infrastructure for transporting crude oil
- 800 miles, 48 inch diameter, Prudhoe Bay to Valdez
- Underground and above ground sections
- Crosses three mountain ranges
- Ambient air temperature as low as –80°F
- Designed for 2.2 Million BPD throughput. Currently at less than 800,000 BPD and declining
- Continued operation of TAPS will require significant increase in throughput

PROJECT FOCUS

- **TAPS was originally designed for transporting ANS crude oil**
- **(A)**
  - **Introduction of GTL products will unavoidably pose some challenges to the operation of the pipeline**
- **(B)**
  - **Anticipated problems include**
    - **Gel formation during cold weather shutdown**
    - **Possibility of vapor formation**
    - **Altered pumping pressure requirements**
    - **Solids precipitation and deposition**

PROPOSED MODE OF GTL TRANSPORTATION THROUGH TAPS

- **Batch Flow**
  - Otherwise known as "slugging": alternate batches or slugs of Crude Oil and GTL are transported through TAPS

- **Commingled Flow**
  - GTL and Crude Oil are premixed and transported through the pipeline as a single phase fluid

PROPOSED MODE OF GTL TRANSPORTATION (CONT'D)

Transportation Modes:

- **Batch Mode A: As – is Batching**
- **Batch Mode B: Batching with pigs**
- **Batch Mode C: Modern Batching**
- **Commingled Mode**

BATCH MODE A: AS-IS

- Batch slugs of GTL and crude oil letting physics control slug movement in TAPS
- Minimal additions to capital and labor
- Increased levels of mixing between slugs

BATCH MODE B: WITH PIGS

- Traditional batching with pigs physically separating oil and GTL
- Pig sensors can detect product movement
- Pigs must be transitioned between pump stations
- Transitioning pigs requires additional labor
- Pigs may cause increased turbulence between slugs

BATCH MODE C: MODERN

- Uses new technology for interface detection and tracking product movement
- Successful use in other pipelines have been reported (proven technology)
- Helps maintain GTL purity better than other modes
- Complex technology, hence expensive to install and maintain, but effective

CAPITAL INVESTMENTS

- New Holding Tanks on Slope
- New Storage Tanks at Terminal
- DCS and Accessories (at inlet and outlet points)
- Relief Tanks at Pump Stations
- Additional Piping
- Pigs (if needed)
- Contingency Plan Capital

COMMINGLED MODE

- Requires minimal capital and labor
- Low grade GTL can be produced at North Slope
- GTL purity is fully lost, but higher output of diesel and gasoline at downstream end

WHY COMMINGLED MODE

- The expected loss of purity of the product mixture and a trade-off between loss in product value due to contamination and cost of keeping the product pure at the terminal

- Flexibility of using existing infrastructure with minimal addition to capital cost for transportation

- The commingled mode of transportation does not require additional facility because the present relief tanks system is capable of handling the crude oil-GTL blend product

GTL TRANSPORTATION ISSUES

- TAPS designed for specific type of crude oil
- GTL flow behavior through TAPS
- Cold temperature effects on the gel strength of the crude oil-GTL blends with respect to cold restart of the pipeline during prolonged shut downs
- The phase behavior of the GTL products and any vapor pressure concerns
- Effects of solids precipitation and deposition of the blends (wax and/or asphaltenes) within the pipe

OPERATIONAL CHALLENGES

TASK	PURPOSE
Gel strength Measurement	Deals with cold restart issues
Density and viscosity Measurement and Modeling	Required to characterize flow conditions In the pipeline for a given fluid blend
Flow Rheology	For pumping horsepower requirement
Solid deposition Study	Evaluate the tendency for asphaltene and wax deposition, crude oil stability, WAT measurements

EFFECT OF GEL STRENGTH

- Fluid gel strengths generally do not pose a problem during normal pipeline operations at high ambient temperatures, but could pose a problem at sub-zero temperatures.

- Gel strengths are reduced as the percentage of GTL in the crude oil-GTL mixture increases even at low temperature of -20°F. This therefore is favorable to pipeline re-start condition after an extended shut down at temperatures down to -20°F (cold re-start condition).

- The potential for cold restart problems after a prolonged winter shutdown of the pipeline increases as fluid gel strengths increase.

DENSITY EFFECTS

- The density of each of the samples was measured at different temperatures from 0°C to 50°C (32°F to 122°F), inclusive.

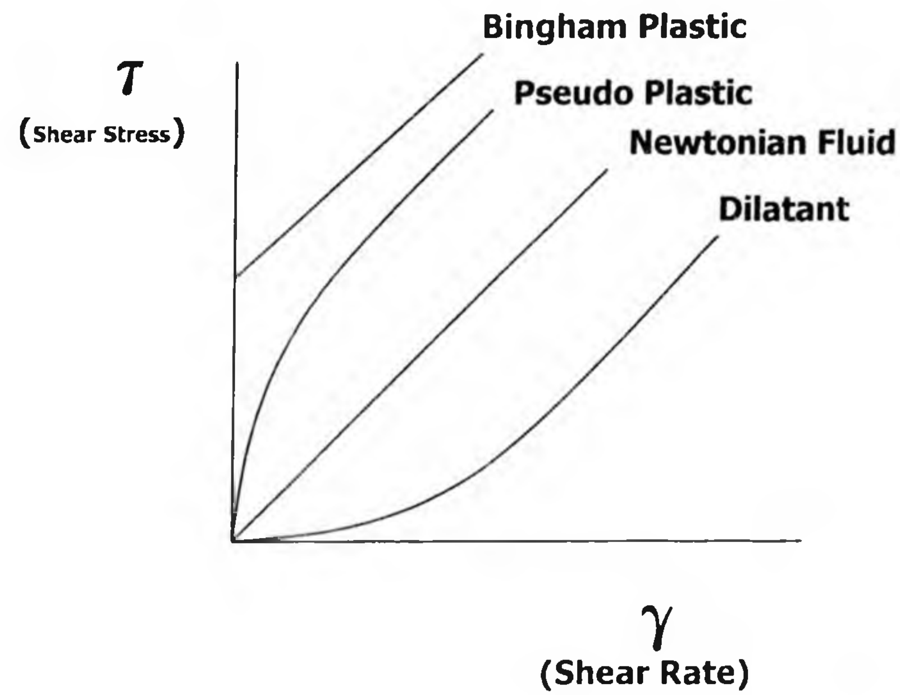
- As expected, the density values decreased with increasing temperature.

- Addition of AKGTL to the samples caused a reduction in density, because the blends contain more light ends than the pure crude oil.

EFFECTS OF RHEOLOGY (SHEAR STRESS VS SHEAR RATE RELATIONSHIP)

Viscous fluid classification for pumping requirements

- **Newtonian**
- **Non-Newtonian**
  - Bingham Plastic
  - Power-law fluids



EFFECTS OF RHEOLOGY (SHEAR STRESS VS SHEAR RATE RELATIONSHIP) (cont'd)

- AKGTL shows pseudoplastic behavior at all temperatures in the given temperature range (50°C to -20°C).

- Crude Oil shows Newtonian behavior at temperatures 20°C and above and shows Bingham plastic behavior below 20°C.

- Blends of AKGTL and Crude Oil shows Pseudoplastic behavior at higher temperatures (above room temperature), Newtonian at intermediate temperatures (around room temperature) and Bingham plastic behavior at lower temperatures (near zero degree Celsius and below) in the given temperature range.

- This Bingham Plastic flow characteristic indicates that high pumping power requirements are necessary to re-start the pipeline after extended shut down at low temperatures.

EFFECTS OF VAPOR PRESSURE

- The vapor pressure increased with the addition of AKGTL but the values are below the minimum TAPS operating pressure, ensuring a single phase only-liquid flow of the blends.

- The bubble point pressure results showed that the blends would flow through the TAPS as compressed liquids from inception to discharge.

- Therefore, Vapor formation in the pipeline as the blends are transported is not possible.

- It is determined that under current TAPS operating conditions and for all blend ratios considered in the study, the fluid will always exist as a single phase liquid through out the pipeline conditions

EFFECTS OF SOLIDS DEPOSIT

- Asphaltene flocculation and deposition is a potential major problem in the transportation of the blends through the TAPS.
- Asphaltenes are stable in pure TAPS crude oil. This means that ANS crude has the ability to retain Asphaltene in solution in TAPS.
- Addition of AKGTL caused a disruption of this stability and precipitation of significant amount of the asphaltenes from the crude oil as a result of its light ends.
- Asphaltene flocculation occurred in a blend containing as little as 5.7% by volume of AKGTL.

CONCLUSIONS

- **The results of the study show that gel strength is not a significant factor of concern at all the four tested ratios of GTL-Crude oil blend mixtures for the TAPS cold re-start after a prolonged shut down at temperatures above -20°F.**

- **The Bingham fluid flow characteristics exhibited by the blends at low temperatures indicate high pumping power requirement during prolonged shut down of the pipeline.**

CONCLUSIONS (cont'd)

- **Based on the phase behavior studies, the GTL-Crude oil mixture will flow as a single fluid system at all the four (1:1; 1:2; 1:3; 1:4) blend ratios.**
- **The mitigation of solids deposition remains the primary challenge of transportation of GTL –Crude oil products through the TAPS.**
- **Under commingled flow profile, decrease in throughput in the TAPS can result to faster and more deposition of these solids along the pipe wall. This will result to frequent pigging of the pipeline or, if left unchecked, can result to pipeline corrosion.**

THANK YOU

QUESTIONS


a great diesel.
deserves a great diesel
GTL
Sasol
Chevron


asfe


GTL CHALLENGE
Sasol
Chevron

SHORT BIO- FOR: GODWIN A. CHUKWU

Dr. Godwin A. Chukwu is a professor in the department of petroleum engineering at the University of Alaska Fairbanks. He received his Ph. D in petroleum engineering from the University of Oklahoma Norman, M.S and B.S degrees in petroleum engineering from the University of South Western Louisiana Lafayette.

Dr. Chukwu has worked for the firms of elf petroleum, Petroleum Associates of Lafayette, Agip Energy and Natural Resources, in different engineering and professional capacities. He has taught both undergraduate and graduate engineering and related economics courses at the University of Port-Harcourt Nigeria, the University of Oklahoma Norman, and currently the University of Alaska Fairbanks. In addition, he has taught several short courses in fluid hydraulics and hydrodynamics, and drilling optimization, as a consultant. He served as the chair of the petroleum engineering department at UAF from 1992-1995 and 1996-2002.

Dr. Chukwu has authored and co-authored over 70 research publications in the areas of drilling, hydraulics, gas-to-liquids transportation, petroleum geology and natural resource utilization. He is internationally known for his work in the area of non-Newtonian fluid hydraulics applied to oil well drilling/production technology, and hydrodynamics of GTL transportation in pipes. His notable research work in gas-to-liquid transportation and operational challenges through the Trans-Alaska Pipeline System was sponsored by the US Department of Energy, and supported by Alyeska Pipeline Service Company.

Dr. Chukwu is a registered professional engineer in the state of Alaska. He has served in several professional bodies and organizations which include the Society of Petroleum Engineers (SPE) and the Accreditation Board for Engineering and Technology (ABET).

Chairman's Opening Remarks:

Ladies and Gentlemen: I will like to welcome every one of you to this 8th Annual Conference on GTL. To some of us, this has become a resourceful and professional event that everyone who has attended once should look forward to. The benefits derived from interactive discussions and deliberations have proved successful from prior years participants' comments.

I will like to make some few comments on the conference focus subject area.: The two most viable options for the utilization of natural gas are the LNG and GTL. These two options are widely pursued world wide, and will be the main focus of this conference with more emphasis on the future of GTL in world energy market.

Declining GTL production costs (due to positive learning curve), growing world- wide diesel demand, projected high crude oil prices, stringent diesel exhaust emission standards, and fuel specifications are driving the petroleum industry to revisit the GTL process for producing higher quality diesel fuels. As of today, Qatar stands out as one of the most active countries that remain committed to achieving dependence on GTL as an alternative fuel source. Companies like Sasol Chevron, Shell, ExxonMobil, BP, Rentech, to mention some, are committed to the development of this resource. I am happy that we have representatives from these companies to share their experiences with us and to update us on their companies' GTL project status.

With world- wide interest in GTL technology on the increase, I find the following GTL industry common denominations (presented by Beatrice Fisher of IFP & Axens, France at the 5th Doha Conference on Natural Gas at Doha, Qatar on February 28, 2005) interesting:

- Educating stakeholders about the impact of GTL projects and the benefits of the GTL industry.
- Helping gas rich countries (other than Qatar) to develop the right policies and practices to develop GTL projects.
- Encouraging policy makers and regulators to consider policies or programs that support GTL products.
- Lowering costs, increasing efficiencies, identifying synergies, reducing emissions and improving project products.
- Developing high value markets for GTL products.

In summary, and borrowing the remarks of Qatar Second Deputy Premier and Minister of Energy & Industry, H.E. Abdulla Bin Hamad Al-Attiyah, at the 5th Doha Conference on Natural Gas, Doha, Qatar (Feb. 28, 2005), "---developing this industry involves greater cooperation and consultation between consumers and producers for market stability", --- "and the potential of consumers to contribute to production projects, and provide

(Chairman's Opening Remarks continues)

satisfactory funding conditions from financial institutions, thus increasing gas production projects which will lead to further industry and consumption growth".

Again, I welcome all of you to this conference and I hope that you will enjoy the presentations and discussions as we progress in the day. Thank you.

Dr. Godwin A. Chukwu, Professor
University of Alaska Fairbanks, USA
October 24 Conference Chairman

OPERATIONAL CHALLENGES IN GAS-TO-LIQUID (GTL) TRANSPORTATION THROUGH TRANS ALASKA PIPELINE SYSTEM (TAPS)

FINAL REPORT
(Reporting period: 10/1/2001 to 6/30/2006)

Principal Author: Godwin A. Chukwu, Ph.D., P.E.

August, 2006

Work Performed under Cooperative Agreement No. DE-FC26-01NT41228

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DISCLAIMER

OPERATIONAL CHALLENGES IN GAS-TO-LIQUID (GTL) TRANSPORTATION THROUGH TRANS ALASKA PIPELINE SYSTEMS (TAPS)

EXECUTIVE SUMMARY

The Alaskan North Slope (ANS) has a huge amount of natural gas reserves, which can be exploited in many different ways. It is seen as an excellent economic potential for the state of Alaska. The estimated ANS proven and recoverable reserves of natural gas in known oil and gas reservoirs is about 38 trillion standard cubic feet (TCF) [1]. Currently the Natural Gas in the Alaska North Slope is primarily used for pressure maintenance, miscible injection, running gas turbines in pump stations 1 to 4, power oil production facilities and for Enhanced Oil Recovery (EOR) projects. Most of the gas may remain unused upon depletion of North Slope recoverable oil and will thus be stranded unless a means of transportation is developed to make it marketable.

The various options being examined for operational and economic feasibility for the optimum use of ANS natural gas include: constructing a new Alaska Natural Gas Transportation System (ANGTS) to transport the gas to lower 48 states via Canada; constructing a shorter Liquefied Natural Gas (LNG) pipeline to Valdez from where the gas would be shipped to the markets; and converting the gas to gas-to-liquid products (GTL), blend it with the ANS crude oil and transport the resulting liquid through the existing Trans Alaska Pipeline System (TAPS). Previous studies [1] proved that the best of these three options is the third option (that is, the GTL option). The GTL technology might also prove the best method for monetizing other stranded natural gas reserves worldwide.

With the dwindling production of oil from the ANS fields, the throughput of oil into the Trans Alaska Pipeline System (TAPS) is declining steadily and is expected to continue to decline in future. It is projected that by the year 2015, ANS crude oil production will decline to such a level (200,000 to 400,000 bbl/day) that there will be a critical need for pumping additional liquid through the pipeline in order to maintain economic operation

of the TAPS [2]. Production of GTL from ANS natural gas and transporting it through TAPS will increase the pipeline throughput and its economic life.

The schematic commercialization of stranded natural gas resources using GTL technology has received much attention from both the government and private industry. As new GTL technologies have improved and matured, energy companies continue to invest significant money to move improved GTL technologies from small pilot facilities to commercial developments. British Petroleum Exploration Alaska (BPXA) has completed and tested a 300 bbl/day pilot GTL facility in Nikiski, Alaska. Production from this pilot facility was to demonstrate a new synthesis gas generation technology and to assess challenges of GTL production in a cold climate. Experiences from this facility may be applied to a possible commercial GTL facility on the ANS.

GTL products are less viscous than crude oil. The viscosity of North Slope oil has been increasing with the increase in production of oil. The TAPS was originally designed for less viscous fluids. Thus the increasing viscosity of the present crude oil might have adverse effects on the life of TAPS. The blending of the light GTL products with crude oil would help in retaining the API of the fluid that the TAPS was originally designed for. Also presently the daily transfer of fluid through TAPS is less than the capacity of TAPS. This increases the tariff on the pipeline. Transporting GTL through TAPS would meet the capacity of TAPS and would decrease the tariff.

The TAPS was specifically designed for transporting ANS crude oil. Introduction of GTL products into the pipeline might lead to some operational problems. Anticipated problems include altered pumping power requirements, possibility of vapor formation, solids precipitation and deposition and gel formation.

The primary goal of the proposed research will be to study the flow of GTL/ANS crude blend mixtures through TAPS in view of these operational challenges. The scope of this work would include experimental and simulation study of the properties of GTL products and their blends at all possible TAPS operating conditions, including a cold weather shutdown.

Conclusions

Based on the work presented in this report, the following main conclusions are drawn. It appears that fluid gel strengths generally do not pose a problem during normal pipeline operations at high ambient temperature, however TAPS operations are far from normal. The potential for a prolonged winter shutdown of the pipeline increases as fluid gel strengths increase. High gel strengths significantly reduce the amount of time available to make repairs and return the pipeline to a flowing condition before restart is possible.

The result of this study also indicates that by altering the final boiling point of the GTL introduced into the pipeline, the gel strength of the commingled GTL and crude oil may be controlled. Additionally, the resulting mixture has gel strength lower than that of crude oil with which the GTL is mixed.

Blends of AKGTL and Taps Crude Oil show Pseudo-plastic behavior at higher temperatures (above room temperature), Newtonian at intermediate temperatures (around room temperature) and Bingham plastic behavior at lower temperatures (near zero degree Celsius and below) in the given temperature range.

Blends of AKGTL and TAPS crude oil indicate that:

GTL has the tendency to flocculate Asphaltenes, as a result of its light ends.

GTL is not as strong a precipitant as n-pentane or n-heptane.

TAPS crude oil is a stable crude in terms of Asphaltene deposition

Considering the low TAPS operating temperature and high flow pressure it is determined from this study that if GTL were to flow through TAPS in either the batch mode or as commingled mixture, under current TAPS operating conditions, the fluid will always exist as a single phase liquid through out the pipeline conditions.

Recommendations

GTL technology may be an available means of recovering and or transporting huge resource of Alaska heavy oils. Feasibilty study and characterization of the flow of blends of AKGTL and ANS heavy oil through the TAPS is necessary. Such study if found feasible, will further be evaluated for economic viability compared to other technologies in place.

A study of solid deposition of GTL/ANS crude oil mixtures under dynamic conditions will be important to investigate. This will help to understand the true behavior of such mixtures for practical applications.

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SPE 100375

Rheology of Gas-to-Liquid Products, Alaska North Slope (ANS) Crude Oil and Its Blends for Transportation Through the Trans-Alaska Pipeline System (TAPS)

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This paper was prepared for presentation at the 2006 SPE Western Regional/AAPG Pacific Section/GSA Cordilleran Section Joint Meeting held in Anchorage, Alaska, U.S.A., 8–10 May 2006.

Abstract

It is projected that by the year 2015, Alaska North Slope (ANS) crude oil production will decline to such a level (200,000 to 400,000 bbl/day) that there will be a critical need for pumping additional liquids through the pipeline in order to maintain economic operation of the Trans Alaska Pipeline System (TAPS). The estimated proven and recoverable gas reserves of 38 trillion cubic feet (TCF) on the North Slope of Alaska can be converted to a high premium liquid product using the Gas-to-Liquids (GTL) technology. The GTL product can be transported from the ANS to the Southern port of Valdez, Alaska through the TAPS.

One of the proposed modes of transportation of the GTL products from ANS to market is by commingling it with crude oil as a single phase and pumping the mixture through the TAPS. This mode of transportation changes the properties of the GTL as well as the crude oil. The focus of this work therefore was to determine the physical and chemical properties of GTL and its blends with ANS crude oil, analyze the energy requirements for flowing the mixture through TAPS, and to determine the optimum blend ratio that would maximize the transportation economics. Four blends of GTL/crude oil mixture in the ratios of; 1:1; 1:2; 1:3; and 1:4; were prepared for their rheological evaluation and pressure drops at different temperature conditions.

The results of the analysis show that flow behavior of the GTL and GTL blends are temperature sensitive. Viscosity and density of the blends were found to decrease with increasing amount of GTL and increasing temperature. The optimum GTL/crude oil blend ratio of; 1:2.5 (28%: 72%) was determined to take full advantage of the economics of commingled flow of GTL/crude oil mixture through the TAPS.

Introduction

The ANS has a huge amount of natural gas reserves, which can be exploited in many different ways. It is seen as an excellent economic potential for the state of Alaska. The estimated ANS proven and recoverable reserves of natural gas in known oil and gas reservoirs is about 38 TCF (Thomas, et al. 1996). Currently the Natural Gas in the ANS is primarily used for pressure maintenance, miscible injectant (MI), running gas turbines in pump stations 1 to 4, power oil production facilities. Most of the gas may remain unused upon depletion of ANS recoverable oil and will thus be stranded unless an option for transportation is developed to make it marketable. The various options being examined for operational and economic feasibility for the optimum use of ANS natural gas include: constructing a new Alaska Natural Gas Transportation System (ANGTS) to transport the gas to lower 48 states via Canada; constructing a shorter pipeline to Valdez from where the gas would be converted to Liquefied Natural Gas (LNG) and shipped to the markets; and converting the gas to gas-to-liquid products (GTL), blend it with the ANS crude oil and transport the resulting liquid through the existing TAPS. Previous studies (Thomas, et al. 1996) proved that the best of these three options is the third option (that is, the GTL option). The GTL technology might also prove the best method for monetizing other stranded natural gas reserves worldwide.

With the dwindling production of oil from the ANS fields, the throughput of oil into the TAPS is declining steadily and is expected to continue to decline in future. It is projected that by the year 2015, ANS crude oil production will decline to such a level (200,000 to 400,000 bbl/day) that there will be a critical need for pumping additional liquids through the pipeline in order to maintain economic operation of the TAPS (Khataniar et al, 2004). Production of GTL from ANS natural gas and transporting it through TAPS will increase the pipeline throughput and its economic life.

The TAPS was specifically designed for transporting ANS crude oil. Introduction of GTL products into the TAPS might lead to some operational problems. Anticipated problems include altered pumping power requirements, possibility of vapor formation, solids precipitation and deposition and gel formation.

The objectives of this study are:

1) to evaluate rheology and density of GTL, ANS crude oil and their blends at different temperatures;
2) to determine and analyze the energy requirements for flowing the fluids through the TAPS;
3) and to determine the optimum GTL/Crude Oil blend ratio that can flow through the TAPS.

Study Background and previous work:
The schematic commercialization of stranded natural gas resources using GTL technology has received much attention from both the government and private industry. As new GTL technologies have improved and matured, energy companies continue to invest significant resources to move improved GTL technologies from small pilot facilities to commercial developments. BP Exploration (Alaska), Inc. (BPXA) has already started the production of GTL from pilot GTL facility in Nikiski, Alaska and also started the production to demonstrate a new synthesis gas generation technology and assess challenges of GTL production in a cold climate. Experiences from this facility may be applied to a possible commercial GTL facility on the ANS.

GTL products are less viscous than crude oil. The viscosity of North Slope oil has been increasing with the increase in more and more vis ous oil production. The TAPS was originally designed for less viscous fluids. Thus the increasing viscosity of the present crude oil might have adverse effects n the life of TAPS. The blending of the light GTL products with crude oil would help in retaining the API of the fluid that the TAPS was originally designed for. Also presently the daily transfer of fluid through TAPS is less than the capacity of TAPS. This increases the tariff on the pipeline. Transporting GTL through TAPS would meet the capacity of TAPS and would decrease the tariff.

Modes of transportation:
The two modes of flow considered for GTL transportation through TAPS are:
1) *Batch mode*: - The transport of GTL and crude oil in slugs or batches results in creation of an interface zone between both fluids. This interface zone is made up of air pockets and a mixture of both fluids. The magnitude of the interface zone is a function of the fluid velocity, density differences, viscosity, pipe diameter, pipe length, time and composition (Baum et al, 1998). A complex two-phase flow is created by this mode.
2) *Commingled mode*: - In this mode of transportation, the crude oil and GTL are blended before being sent through the pipeline as a single liquid phase mixture.

The pressure drop and energy balance equations were determined for both batch and commingled flow modes of transporting GTL through the TAPS. The solutions to these equations were presented for determining pressure gradient and optimum slug length for batch operations. The Bernoulli equation of pressure for the flow of fluids in pipes was used to derive flow equations applicable to specified operating conditions or constraints of the TAPS, (Akwukwaegbu, 2001).

The results of the Akwukwaegbu study indicates that the pressure gradient obtained from the batch flow calculations are higher than those obtained from that of commingled flow. The reason is that for batch flow, the pressure gradient is the ratio of the total pressure drop across the slug to the length of the slug, whereas for commingled flow, it is the ratio of the total pressure drop to the length of the pipe segment. In pressure drop calculations different flow patterns that might occur in either batch or commingled flow should be taken into account.

In commingled mode of flow calculations, the GTL and crude oil samples were premixed to represent a single phase fluid system. Since both GTL and crude oil are hydrocarbons they should have a similar fluid properties and a homogenous mixture can be expected. This was supported by the results of the tests conducted by Ramakrishnan (2000). Phase behavior results by Sharma (2003) show that at TAPS temperature and pressure conditions the mixture of GTL and crude oil is single homogenous phase. Thus in this study, the GTL/crude oil blends will be treated as a single liquid phase.

Rheology:
When a fluid is flowing, a force exists in the fluid that opposes the flow. This force is known as shear stress, which can also be seen as the frictional force between the two adjacent layers of fluid. And the relative velocity with which an individual layer moves with the neighboring layers is shear rate. The shear stress is a function of pressure and the shear rate is a function of geometry and average velocity of the fluid. The relationship between shear stress and shear rate defines the flow behavior of the fluid.

The rheology of fluids is dependent on their shear stress-shear rate relationship. Linear relationship of shear stress and shear rate on a Cartesian plot, which passes through the origin, indicates that the fluid exhibits Newtonian characteristics. The non-Newtonian behavior of fluids can be characterized by either the Bingham Plastic or Power-Law fluid flow model (among others), depending on the fluid's shear stress-shear rate relationship. Figure 1 shows the rheogram of Newtonian, Bingham Plastic and Power-Law fluids.

The corresponding equations of these fluid models are given in equations 1, 2 and 3, respectively.
For Newtonian fluids:

$$\tau = \mu\gamma \tag{1}$$

The absolute or true viscosity (μ) is constant for Newtonian fluids.
For Bingham Plastic Fluids:

$$\tau = \mu p\gamma + \tau_o \tag{2}$$

The plastic viscosity (μ_p) of Bingham plastic fluids is described as that part of resistance to flow caused by mechanical friction. Primarily, it is affected by (a) solids concentration (b) size and shape of solids, and (c) viscosity of the fluid phase. An increase in plastic viscosity indicates an increase in the percent by volume of solids, a reduction in size of the solid particles, a change in the shape of the particles, or a combination of all. Yield point is that part of the resistance to flow caused by the attractive forces between particles.

For Power-Law fluids:

$$\tau = k(\gamma)^n \quad (3)$$

n and k are called the parameters of Power-Law model. The parameter n shows the degree of deviation of fluid from Newtonian fluid characteristics. Based on the value of n, fluids can be classified as follows:

n = 1 ---Newtonian *examples: air, water, high viscosity fuels*

n < 1 ---Pseudoplastic *examples: grease, printer's ink, soap*

n >1 ---Dilatant *examples: clay, starch in water, peanut butter*

Experimental Methodology:

Laporte light GTL samples were used for the initial experimental investigation in this study. This GTL was distilled in three sample cuts as suggested by Timmcke (2002) at temperatures of 254, 302 and 344°C so that a wide range of GTL products that may be transported through TAPS is obtained for the study. GTL field samples were received from BPXA GTL pilot plant. The samples therefore are referred to as AKGTL or GTL and the sample cuts are denoted as GTL254, GTL302 and GTL344. Crude oil samples were taken from the TAPS at pipeline conditions and preserved in constant pressure Welker cylinders. GTL and crude oil sample blends were prepared gravimetrically in the ratios of 1:1, 1:2, 1:3 and 1:4 for density, rheology and viscosity measurements at different temperatures.

Density Measurements:

The density of the GTL cuts, AKGTL, TAPS crude oil and their blends were determined in the laboratory using the Anton-Paar digital densitometer at atmospheric pressure. Two different crude oil samples were used to blend with the GTL cuts and AKGTL. This work concentrates more on study of AKGTL compared to the GTL cuts because AKGTL might be the representative sample of the GTL that would be produced from the ANS natural gas. A wide experimental range of temperature (0°C to 50°C) was selected for AKGTL and its blends with crude oil. The results obtained from the density measurements are shown in tables1 through 4.

It can be seen from the results of density measurements that AKGTL has higher densities at all temperatures than GTL344. Hence AKGTL is heavier than all the GTL cuts.

Rheology and viscosity measurements:

Brookfield's cone plate viscometer was used to measure the viscosity of the fluid samples. The readings within the 10% to 100% torque range were accepted for accuracy as mentioned in the manual. For viscous fluids and at lower temperatures the 100% torque is achieved at comparatively lower shear rates. Hence fewer data points are obtained at low temperatures as well as for viscous fluids. These shear stress values are plotted against shear rate values. Regression coefficient (R^2) is used to decide the best fit curve. Flow behavior parameters n & k and viscosities are determined with the help of these curves. GTL, crude oil and their blends are then classified as Newtonian or non-Newtonian fluids based on the best fits and values of n and k.

Crude oil

TAPS crude oil shows Newtonian behavior at higher temperatures (>20°C). At lower temperatures it shows Bingham Plastic behavior with some yield point. Viscosity of crude oil is determined by the slope of the shear stress vs. shear rate plot. The experimental results are plotted on the cartesian graph. The representative rheograms at temperatures 50 °C, 30 °C and 10 °C are shown in figures 2 through 4. The classification of crude oil behavior based on temperature is tabulated in table 5. The table also summarizes the absolute viscosities for Newtonian behavior and plastic viscosities (PV) and the yield values for Bingham Plastic behavior.

AKGTL

From the experimental results, the rheograms of AKGTL field sample were plotted on the cartesian graph. Log-log plots (log γ vs log γ) were used to determine the n and k values. From the plots and values of n it was concluded that GTL shows pseudoplastic behavior at all the temperatures in consideration. The representative rheograms and the log-log plots at temperatures 50 °C, 30 °C, 10 °C and -10 ° C are shown in figures 5 through 8. The n and k values are tabulated in table 6.

AKGTL/Crude Oil Blends

Blends of GTL and crude oil show Newtonian, pseudoplastic and Bingham Plastic behavior depending on the temperature. At higher temperatures (above room temperature) pseudoplastic behavior is observed, at intermediate temperatures (around room temperature) Newtonian behavior can be seen whereas at lower temperatures (around 0 °C and below) Bingham plastic behavior is noted. This is summarized in tables 7 through 10.

Application of Pressure Drop:

The total pressure drop in TAPS while transporting fluid from pump station one to the Valdez Marine terminal is due to friction, elevation change and some other minor losses like fittings losses. Pressure losses due to acceleration are neglected since it is assumed that the flow rate is constant. For calculation purpose, TAPS is divided into 5 segments between pump station one (PS-1) on the ANS and Valdez Marine terminal. Only the operating pump stations are considered here. The center line elevation of each pump from sea level, elevation change between two consecutive pump stations, distance of each pump station from PS1 is given in table 12. The table also shows the assumed values of minor losses, which were used for calculations. These minor losses are considered constant for all the fluids. The data in table 12 were calculated using appropriate model based on the rheological evaluation results (either Newtonian or Power Law). Pressure drop per mile is evaluated at various temperatures based on the daily throughput of 1.02 MMBPD. Total pressure drop along TAPS at various temperatures for

GTL samples, crude oil and their blends are shown in tables 13 through 15. From tables 13 through 15, pressure drop along TAPS can be found at various temperatures considering that particular temperature is constant throughout the TAPS length. In reality, temperatures along the TAPS varies, hence average pressure drop at current TAPS temperature conditions between pump stations are shown in table 16. These average temperatures are assumed to remain constant throughout the particular pipe segment in consideration.

Power required to transport fluids between Pump Stations:

The hydraulic horsepower required to flow liquid from one point to the other is a function of the pressure drop between the points, and the fluid flow rate. The hydraulic horsepower required to flow fluid between two consecutive pump stations was calculated. In this study, the flow rate is kept constant at 1.02 MMBPD. Pressure drop varies with temperature and fluid behavior. Details on pump specifications and efficiency are not considered in the present analysis. The results are tabulated in tables 17 through 19 Hydraulic horsepower required between pump stations at the present average temperature conditions for AKGTL, crude oil and their blends is shown in figure 9.

Optimum blend ratio for transportation through the TAPS:

In order to determine the optimum blend ratio or optimum amount of GTL in the blend, average pressure drop per mile due to respective fluid was calculated and plotted against percent amount of GTL in blend as shown in figure 10. The minimum of this curve gives the optimum amount of GTL in the GTL/crude oil blend. It should be noted that various factors such as flow behavior parameters of the fluid, pipeline characteristics, elevation changes, temperature conditions among others are responsible for this pressure drop. Hence optimum blend ratio also depends on all these parameters. From figure 10, it can be seen that at 28% of GTL, the curve shows minimum. Thus 28% GTL in GTL/ANS crude oil blend is the optimum blend ratio.

Conclusion:

Blends of AKGTL and crude oil show Pseudo-Plastic behavior at higher temperatures (above room temperature), Newtonian behavior at intermediate temperatures (around room temperature) and Bingham Plastic behavior at lower temperatures (near zero degree Celsius and below) in the given temperature range.

The blend containing 28% GTL and 72% crude oil ratio is the optimum blend which is function of various parameters such as fluid temperature, flow behavior parameters, pipeline characteristics, and elevation changes in pipeline among others.

Acknowledgement:

The authors thank Alyeska Pipeline Service Company and BP Exploration Alaska for their support of this study. The financial support by both US Department of Energy and the University of Alaska Fairbanks are acknowledged and appreciated.

Disclaimer:

The opinions, findings, conclusions, and recommendations expressed herein are those of the authors and do not necessarily reflect the views of the US Department of Energy and/or BP Exploration (Alaska) Inc.

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April 2004

Transportation of GTL Products From the Alaskan North Slope

Gas-to-liquid (GTL) conversion is an emerging technology that very likely will be widely used within the next decade. With its vast natural-gas resources, the Alaskan North Slope (ANS) will be one of the first areas in the U.S. to exploit this new technology. The objective of this study is to evaluate the technical and economic feasibility of transporting GTL products through the Trans-Alaskan pipeline system (TAPS).

Introduction

The ANS contains some of the largest hydrocarbon-gas reserves in the U.S. The proven and recoverable conventional-natural-gas reserves in developed and undeveloped fields in the ANS are estimated to be 38 Tscf, and estimates of additional undiscovered gas reserves in the Arctic fields range from 64 to 142 Tscf. Produced gas from the ANS oil fields is separated and processed in surface production facilities where natural-gas liquids (NGLs) and the components used for miscible injectant (MI) are separated from the gas stream. Some of the NGLs are mixed with crude oil for transportation through the TAPS. The remaining NGLs and MIs are used in enhanced-oil-recovery operations. Most of the lean gas is injected back into the reservoirs for pressure maintenance.

GTL technology, where gas is chemically converted to fuel-grade liquid products, was first used during World War II. In recent years, GTL technology has re-emerged as the technology for producing clean, environmentally friendly fuels. Although there are several different methods for GTL conversion, the basic GTL-conversion process considered in this study is a two-step process. In the first step, natural gas is combined with oxygen or air to form a mixture of carbon monoxide and hydrogen called synthesis gas by use of steam reforming, partial oxidation, or autothermal reforming. In the second step, synthesis gas is converted into liquid fuel, usually through the Fischer-Tropsch (FT) synthesis process. The liquid hydrocarbons produced by FT synthesis are free of impurities like sulfur and primarily consist of straight-chain hydrocarbons.

Transportation of the natural gas from the ANS is the key issue in monetization of this valuable resource. The existing infrastructure for transporting crude oil from the ANS fields is the 800-mile-long TAPS, extending from Prudhoe Bay to the marine terminal at Valdez. With declining oil production from the ANS fields, the oil throughput in TAPS is declining. Currently, 4 of the 12 pump stations are shut down because of the decline, and the pipeline is operating at one-half its design capacity. It is projected that by 2015, ANS crude-oil production will decline to such a level (200,000 to 400,000 B/D) that there will be a critical need to pump additional liquid through the pipeline. The vast natural-gas resources of the ANS can provide an adequate liquid volume for economic TAPS operation by use of GTL technology.

Transportation Issues

Because TAPS was originally designed to carry a specific type of crude oil, the possibility of flowing GTL products through TAPS raises several questions. Operational problems associated with transporting GTL products through TAPS depend on the physical and chemical properties of the GTL products and GTL-product/ANS-crude-oil blends.

Ability to Transport GTL Products. TAPS was specifically designed for Prudhoe Bay crude, which is 24 to 32°API. GTL products have a much higher API gravity and physical and chemical properties significantly different from those of Prudhoe Bay crude. Thus, a thorough study of GTL-products flow hydraulics and compatibility is necessary to evaluate potential problems in GTL-products transportation through TAPS.

Gelling and Cold-Restart Issues. Because FT-based GTL products are paraffinic, they tend to form gels at low temperatures. This can be a particularly troublesome issue for TAPS because of the extremely cold Arctic environment. In an extended TAPS emergency shutdown in the winter, the fluids inside the pipeline will gradually cool and form a gel. The pressure required to break the gel and restart the pipeline could be greater than the pump and pipeline capacities. Thus, pipeline throughput must be tested to ensure that a cold restart after a shutdown is possible.

Effect of Solids Precipitation. Presence of GTL products may increase solids precipitation (wax and/or asphaltene) significantly within the pipeline. Buildup of such deposits may impede fluid flow to the extent that the deposits have to be removed mechanically.

Objectives
The first objective of this study was to address the cold restart of TAPS by measuring the gel strength of FT-based GTL products and GTL-product/crude-oil blends. Because restart feasibility depends on the cold-temperature gel strength of the transported fluid, gel strength is the key parameter determining feasibility of transporting a given GTL product through TAPS. The second objective of the study was to conduct a preliminary economic analysis of GTL-product transportation through TAPS, considering the fluid properties and flow hydraulics.

Gel-Strength Measurements
Gel strength gives an indication of the cold-restart pressure at which the liquid in the pipeline will yield. Thus, gel strengths of various GTL products and GTL-product/ANS-crude blends were determined by the rotating-vane technique at different temperatures.

Sample Preparation. FT-based GTL products obtained from two different sources were used to simulate the variation in GTL products that could be produced at an ANS facility. The first GTL product used in this study, GTL1, was a light-hydrocarbon liquid. The second GTL product, GTL2, was a diesel fuel obtained from FT synthesis. In addition, heavy alkanes were separated from a wax sample by a vacuum-distillation process to produce only the 20% overhead fraction. This wax distillate was gravimetrically mixed with GTL1 to create GTL samples with varying wax content. Because gel strength is a function of wax content, samples were made with varying wax content so the limiting conditions for flow through TAPS could be estimated. GTL2 was not mixed with the wax distillate to represent the scenario where clean diesel is produced and transported through TAPS.

Measurement Procedure. Test temperatures were selected on the basis of cold ramping the GTL-product/crude-oil blends from 90 to -20°F over a 21-day period. The temperature-decay curve used for sample conditioning and test-temperature selection was based on TAPS cold-restart data supplied by the pipeline operator. The temperature ramp simulates fluid cooling inside TAPS under winter-shutdown conditions.

Gel strength of the samples was determined by the rotating-vane method. This method uses commercial rotary viscometers and vane spindles, which extend horizontally through a sample to minimize slippage at the spindle wall. This method determines the minimum torque necessary to initiate oil movement at low shear and subsequent gel breakdown after flow initiation. Gel strengths were measured at predetermined temperatures along the cooling ramp.

Results and Discussion. In several cases, gel strength was beyond the maximum torque capacity of the viscometer. Gel strengths of GTL1/crude-oil blends are generally low at 40 to 60°F, but increase rapidly as temperature drops to 20°F. Gel strength can increase significantly in the presence of even moderate amounts of wax components in the GTL product.
The results for GTL2 also show that gel strength increases rapidly with decreasing temperature. The pure form of GTL2 showed high gel strength at 20°F; however, gel strength at 20°F decreased markedly when GTL2 was blended with crude oil. For the GTL2/crude-oil blends, gel strengths at 0°F were quite high.

Results indicate that gel strength of GTL products or GTL-product/crude-oil blends can increase abruptly once the temperature falls below a threshold. The threshold temperature can be as high as 20°F and depends on wax content. This may pose a serious problem for pipeline cold restart. To be transported through TAPS, the GTL products manufactured at ANS must be relatively free of wax components. This may require the products from FT synthesis to be hydrocracked to remove the higher paraffins before entering the pipeline.

Because the pure GTL sample gels at a higher temperature than GTL-product/ crude-oil blends, batching of GTL products could be more troublesome than commingled flow. Rigorous studies are needed to identify the upper limit for the paraffin quantity and molecular weight that is acceptable in GTL products for TAPS flow.

Economics of GTL Transportation
There are two possible ways to transport GTL products through TAPS: (1) batch or slug mode, where GTL products and crude oil flow as alternate slugs, and (2) commingled or blended mode, where GTL products and crude oil are mixed to form a single phase. In either mode, the feasibility and economics of moving GTL products through TAPS depend on the physical properties of the GTL products and GTL-product/crude-oil mixtures. Table 3 in the full-length paper lists the economic assumptions.

The GTL products are assumed to have a premium of 125% over the crude-oil price. Also, it is assumed that GTL-product quality is maintained in the batch mode. For the commingled mode, the

GTL-product/ crude-oil mixture is assigned a premium of U.S. $1 over the crude-oil price to account for the increased gasoline or diesel yield after refining.

The results of the economic analysis are presented in the form of rate of return (ROR). The ROR increases with decreasing capital expenditure (CAPEX) for both modes of transportation. The CAPEX, expressed in U.S. dollars per daily barrel (U.S. $/Dbbl), represents initial investment for the ANS GTL plant only and does not include the additional capital investment necessary in the batch mode for liquid storage. The batch mode shows higher ROR than the commingled mode (**Fig. 1**), although the batch mode had higher initial expense than the commingled mode. The difference in ROR of the two modes decreases with decreasing CAPEX, indicating that the two modes may become equally economical if the CAPEX is sufficiently small.

Fig. 1—ROR for batch and commingled modes.

The U.S. $1 premium of the GTL-product/crude-oil mixture used in the base case of commingled mode is entirely arbitrary because it is very difficult to quantify the increase in product value achieved by adding a GTL product to the crude oil. Therefore, a sensitivity analysis was performed by varying the premium applied to the commingled mode from U.S. $1 to $3 more than the crude-oil price. For a fixed CAPEX of $25,000/Dbbl, as the mixture premium increases from $1 to $3, the ROR of the commingled mode approaches that of the batch mode.

Conclusions

This study indicates that transportation of GTL products through TAPS may pose significant problems from the cold-restart point of view. From the preliminary economic analysis, batch-mode transportation appears to be more economical than commingled mode. However, the difference may lose significance as CAPEX decreases and/or the premium for the commingled product stream improves. Because blending GTL products with crude oil tends to lower gel strength significantly and aid restart, the commingled mode may emerge as a more viable option than the batch mode from a technical standpoint.

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This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 86931, "Technical and Economic Issues in Transportation of GTL Products From Alaskan North Slope to the Markets," by Santanu Khataniar, SPE, Godwin A. Chukwu, SPE, Shirish L. Patil, SPE, and Abhijit Y. Dandekar, SPE, U. of Alaska Fairbanks, prepared for the 2004 SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, Bakersfield, California, 16-18 March.

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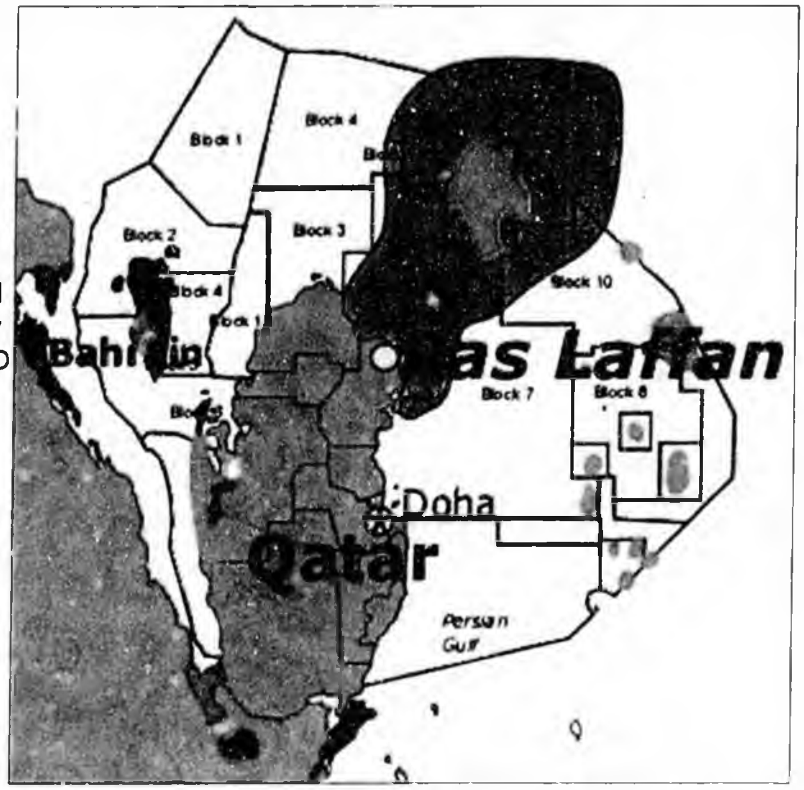
Gas-to-Liquids (GTL) Projects

Qatar Petroleum is actively pursuing a number of world-scale gas-to-liquids conversion projects for the production of synthetic fuels and base oil stocks. The projects are all integrated with offshore development to supply the large amounts of gas needed for these projects. These are active business opportunities that are being pursued, but the status of each of the projects is still at the preliminary stage. A brief summary for each project is given.

Oryx GTL Project
All major project agreements have been signed with the relevant parties. Oryx GTL Ltd. was established at the end of January 2003 as a JV company between Qatar Petroleum (51%) and Sasol (49%). The design capacity of the project is 34,000 BPD of gas-to-liquid fuel. The EPC contract was awarded to Technip and the 33-month contract is being executed from their Rome office. The project reached financial close on 18 March 2003 with EPC contract effective from 19 March 2003.



His Highness Sheikh Tamim Bin Hamad Al Thani, the Heir Apparent, on 7 December 2003 laid the Foundation Stone for the Middle East's first gas-to-liquids plant.

The GTL plant will be ready for start-up in December 2005 and first product will enter the international market during the second quarter of 2006.

QP and Sasol Chevron have signed a Memorandum of Understanding (MOU) for the ORYX GTL Expansion project and have discussed the technical and business principles that will support the planned increase in the output of the foundation plant to 100,000 bbl/day. This will involve defining the feasibility of a three (3) train, 65,000 bbl/day facility with an expected start up by 2009.

Pearl GTL
Shell's GTL is an integrated project which will develop about 1.6 BSCFD of North Field gas to produce approximately 140,000 BPD of synthetic fuels and base oils. The project will be developed in two phases with the first phase operational in 2009, producing around 70,000 bpd of GTL products with the second phase to be completed less than two years later. Qatar Petroleum and Qatar Shell GTL Limited (Shell) signed the Development and Production Sharing Agreement (DPSA) for Pearl GTL in July 2004.

The first of two appraisal wells in the North Field were drilled in February 2004 and the Front End Engineering and Design (FEED) contract was awarded to JGC Inc. of Japan in March 2004.

Sasol Chevron
Sasol Chevron submitted a Project Profile Proposal to QP in July 2002 for an integrated upstream/downstream GTL project to produce 120,000 BPD of GTL product in two phases. The project will produce naphtha and diesel as the primary products. A Statement of Intent was signed for this project in November 2002.

As part of its ongoing project work, Sasol Chevron submitted a Scoping Study to QP in June 2003. Progress has yet to be made on commercial issues to enable further progress with the technical development of the project.

Initial indications were for startup of the project by 2010, but a revised startup date will be produced when the next round of negotiations with Sasol Chevron commences.
QP and Sasol Chevron have also signed a Letter of Intent (LOI) to examine GTL Base Oils opportunities in Qatar.

QP and Sasol Chevron have agreed to pursue the opportunity to develop a 130,000 bbl/day upstream/downstream integrated GTL project based on the Sasol Slurry Phase Distillate Process and utilizing resources from the North Field. This will involve defining the feasibility of a six (6) train facility with an expected start up by 2010. These efforts will lead to the establishment of a Heads of Agreement (HOA) for the project.

ExxonMobil
ExxonMobil GTL project is for the production of synthetic GTL products in excess of 150,000 BPD. Feedstock for the GTL Plant will be provided from two wellhead platforms; approximately 1.8 BSCFD will be required to yield the target GTL production. The project will produce base oil stocks in addition to the synthetic fuels.

Onshore gas treatment and NGL recovery plants will benefit, to the maximum extent possible, from the existing RasGas infrastructure to reduce the overall project cost. LPG, condensate and sulphur storage/loading will most likely be shared with other ongoing projects at Ras Laffan.

The HOA signed in July 2004 specifies the principal terms for the project that will be defined in a Development and Production Sharing Agreement (DPSA). The term of the DPSA will be 25 years from the start of production, which is expected to commence in 2011.

ExxonMobil will drill an appraisal well for the GTL project in 2004, and will supplement the extensive preliminary front-end engineering and design (pre-FEED) undertaken earlier. FEED is expected to begin upon execution of the DPSA.

Marathon
The Marathon GTL project will produce approximately 120,000 BPD of naphtha and diesel. The project will consist of two trains of equal capacity. Phase I first commercial production is planned for 2010. Offshore development is based on two unmanned wellhead platforms and two wet scheme pipelines configuration.

Marathon is considering introducing shareholders to the project; shareholders will include PetroCanada, Occidental and the Offset Group. Details regarding the venture partners will probably be concluded during 2004.

The project will be executed on a Production Sharing Agreement basis. Marathon's pre-FEED work was completed during the last quarter of 2003 and it is expected that commercial negotiations will commence during early 2004.

ConocoPhillips
ConocoPhillips is planning to develop its GTL project in two phases, each producing approximately 80,000 BPD of GTL products - naphtha and diesel using CoPOX technology. Two wellhead platforms with adequate number of wells will provide the required feedstock for the GTL plant.

The company completed a feasibility study that was submitted to QP mid 2003. A Statement of Intent to proceed with the project was signed with QP in December 2003. The company intends to proceed with pre-FEED work during 2004. Startup of the first phase of the plant is scheduled for 2010. The project is structured on the basis of a Production Sharing Agreement, as with all other large-scale GTL projects.

The company has successfully completed the construction of a 400 BPD semi-works plant at its refinery in Ponca City, Oklahoma and commissioning of the plant was well underway at the end of December 2003. ConocoPhillips will demonstrate its process during 2004 and it expects to be able to commence commercial negotiations in 2004 also.

Petrochemicals

Cracker at Ras Laffan
A Joint Venture Agreement (JVA) was signed on 13 June 2002 between Q-Chem II (53.31%), Qatofin (45.69%) and QP (1%) to establish a steam cracker at Ras Laffan with design capacity of 1,300,000 MMTA of ethylene.

An ethylene pipeline from Ras Laffan to Mesaieed will supply ethylene to Q-Chem II and Qatofin plants.

Qatofin
Qatofin is a JV between QAPCO (63%), Atofina (36%) and QP (1%) for production of 450,000 MTPA of LLDPE adjacent to QAPCO site. Feasibility study was completed in December 2002. ITB document for EPC contract was sent to bidders on 22 July 2003. Negotiations continued on several project agreements. The estimated start-up of the project is third quarter 2008.

Q-Chem II Project
An amended JVA was signed on 13 June 2002 between QP (51%) and Chevron Phillips (49%) to establish an ethylene derivatives plant at Mesaieed, adjacent to the Q-Chem plant, with a design capacity of 350,000 MTPA of HDPE and 350,000 MTPA normal alfa olefins.

Feasibility study was completed in December 2002. FEED contract was awarded to Aker-Kvaerner. The estimated start-up of the project is third quarter 2008.

DME Project w'th MGC
A letter of intent was signed on 10 June 2003 with Mitsubishi Gas Chemicals (MGC) and ITOCHU to establish a project for the production of Di-Methyl-Ether (DME) at Ras Laffan in Qatar.

The production capacity of the project is 1.7 MMTPA of DME. The project is planned to start-up around fourth quarter 2008.

Fuel Grade-Methanol Project
Heads of Agreement (HoA) was signed with Petroworld Ltd on 14 September 2003 for the development of a large scale fuel grade methanol project targeting on out put of 12,000 to 15,000 MTPD at Ras Laffan. The partners expect the proposed project to come on stream by 2008.

Sport

Qatar International Racetrack
With over 1.5 million on-site attendees to the GrandPrix (GP) in 2002 plus television viewers from more than 200 countries every year for a total annual audience of 5,200 million, it is no wonder that Qatar is building a MotoGP Racetrack. Over 320 million spectators watch each GP!
The Qatar MotoGP Grand Prix will take place on 2 October 2004, and building has started on the track located on the outskirts of the desert country's capital city, Doha.
For more information click on www.qmmf.com or contact investorsrelations@qatartourism.gov.qa.

Asian Games 2006

As part of the infrastructural obligations for hosting the Asian Games, construction of the Asian Games City has began. Once completed, over 30 sports facilities will be in place. Existing buildings are being renovated as new ones being built, including Al Sadd Stadium, Al Rayyan Sports Centre, Al Ilihad Sports Centre, Al Arabi Sports Centre, Swimming Centre (Aquatic) and Khalifa Stadium.
For more information, click on www.qatarolympics.org, www.dohasiangames.org or contact investorsrelations@qatartourism.gov.qa.

Doha Golf Club
Doha Golf Club will undergo extensive renovations and expansions after a customer

survey revealed the need for increased amenities, including a play area for kids and swimming pool. The renovation and expansion includes a ground floor dining hall, new bar area, professional shop, members' bag store, male and female locker areas, ground floor kitchen, service yard, first floor kitchen, restaurant, and bar. New construction projects include swimming pool with Jacuzzi, fitness centre, ground floor main office in a new building, buggy barn, function hall, two staff residential buildings, new academy building, television building, and a nine-hole golf course. For more information, go to www.dohagolfclub.com or contact investorsrelations@qatartourism.gov.qa .

Pearl of the Gulf

$2.5bn 'Pearl of the Gulf' man-made island project set to take off

By late 2006, the first of some 30,000 residents should be living on a man-made island 350 meters off the coast of Doha's West Bay Lagoon.

The ambitious 'Pearl of the Gulf' project was the recent subject of a presentation to the Qatar Tourism Authority (QTA), and features in its new project development and investment opportunities newsletter. Marketing is expected to begin next month.

The $2.5bn project is the brainchild of United Development Company (UDC), Qatar's largest private-sector shareholding company, and is being developed on a fast-track basis with "full government support", say officials.

The master plan and environmental impact study have apparently already received official approval, and a financial advisor is to be appointed soon. It is understood that detailed infrastructure and landscaping design has already been tendered.

Apart from over 7,500 high-quality dwelling units, the island development will also have three luxury hotels offering around 900 rooms between them, retail units covering approximately 60,000 square meters, and community infrastructural facilities such as entertainment centers, restaurants and parks.

The island is even expected top have its own private schools. An 'island city within a city' Pearl of the Gulf is to have ten distinct, but inter-related precincts. Officials say that under an agreement signed between UDC and the Government of Qatar almost a year ago, UDC would be granted freehold title to the island, together with the right to sub-divide and re-sell the property.

With three huge bays, designed to maximize its water-frontage, the island will, according to the Master Plan, also have four marinas to accommodate up to 700 boats. The first occupants are expected to take possession at the beginning of the fourth quarter of 2006.

UDC has emphasized that "through the process of an international design competition, a Master Plan and an Environmental Impact Study prepared by international consultants, the island has been positioned with the greatest respect to marine environment and topography in order to achieve both environmental integrity and construction practicality."

source : The Peninsula

For more information, click on www.udcqatar.com or contact investorsrelations@qatartourism.gov.qa .

North Beach Development

PROSPECTS FOR DEVELOPMENT OF ALASKA NATURAL GAS: A REVIEW

As of January 2001

by

Kirk W. Sherwood and James D. Craig

U.S. Department of the Interior

Minerals Management Service

Resource Evaluation Office
Anchorage, Alaska

This report is available online at *http://www.mms.gov/alaska/re/reports/rereport.htm*
A Compact Disk version of the report (in PDF format) may be obtained by contacting Rance Wall, Regional Supervisor for Resource Evaluation, Minerals Management Service, 949 E. 36th Ave., Rm. 308, Anchorage, AK 99508-4362, or at Ph. 907 271 6078, or at e-mail *rance.wall@mms.gov*

1. EXECUTIVE SUMMARY

Alaska Gas: Key Drivers and Issues

- The first gas production from northern Alaska will focus on the proven, low-cost reserves at Prudhoe Bay (26 tcf).
- The most likely scenario for exports of northern Alaska gas is a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada. No decision has yet been announced. The State of Alaska, Yukon Territory, and most stakeholders advocate a highway route. Existing regulatory permits and international treaties, subject to review, authorize the highway route.
- Phillips Alaska estimates that prices above $3.50/mcf at Chicago city gate are needed for economic success. Chicago city gate prices were approximately $8/mcf in January 2001.
- Gas delivery to U.S. via gas pipeline from Prudhoe Bay is not expected before years 2007-2010. Regulatory delays or litigation could delay it.
- The gas pipeline will be sized for efficient transportation of the known gas reserves at Prudhoe Bay. For a 4.0 billion cubic feet per day pipeline, excess capacity would become available in year 2023 (assuming a 2007 start up).
- Cook Inlet remaining natural gas reserves (2.56 tcf) will be depleted by year 2012. New gas sources must be located soon to supply the majority of the State's population which lives in the area around Cook Inlet.
- The most attractive gas province in the Bering Sea is North Aleutian basin, which is closed by moratorium until year 2012.
- LNG export models are required for future Bering Sea gas production. Potential gas resources cannot be taken to the U.S. West Coast because there are no LNG receiving facilities. The most likely LNG export models deliver gas to Japan or other Asian Pacific Rim countries.
- Alaska has a huge resource base of discovered and undiscovered gas (217.91 tcf), but 88 percent of this gas is undiscovered. Expensive and time-consuming exploration programs will be required to identify new commercial gas fields.

Summary

Alaska contains 39.88 trillion cubic feet (tcf) of gas remaining in developed and known undeveloped fields. Some of this gas is in fields too small or remote to justify economic development. Of the known gas reserves, 26.92 tcf may be considered available for export at appropriate market prices and pending construction of new gas transportation systems. Most of this gas is in onshore fields and mostly beneath State of Alaska surface or submerged lands. No Federal offshore gas reserves are considered to be readily available for export at present.

Three percent (0.92 tcf) of Alaska's exportable gas reserves occur within fields in the Cook Inlet basin of southern Alaska and are at present dedicated to future LNG exports to Japan. Cook Inlet has 2.56 tcf in total remaining gas reserves, most of which is used locally or converted to fertilizer feedstock. At present rates of consumption, all Cook Inlet gas reserves will be depleted by year 2012.

Ninety-seven percent (26 tcf) of Alaska's expo:table gas reserves occur within fields in or near the Prudhoe Bay field in northern Alaska. The Prudhoe Bay area gas reserve base totals 30.90 tcf (developed fields and Point Thomson field, not including carbon dioxide), but some of this gas will be consumed (current rate 0.2 tcf/yr) by future (oil and gas) production activities at Prudhoe Bay. The stranded gas reserves at Prudhoe Bay are presently attracting proposals for construction of a gas transportation system that can take the natural gas to markets outside of Alaska.

In the Mackenzie delta area of Canada (300 miles east of Prudhoe Bay), exploration drilling from 1970 and 1989 discovered 53 oil and gas pools about equally divided between the onshore and offshore areas. The Mackenzie delta area contains approximately 9-12 tcf of discovered gas, some of which may be in pools sufficiently large to justify construction of a new gas pipeline to take the gas south to Alberta. The largest gas field is Taglu (2.07 tcf) located onshore. All of the Mackenzie delta discoveries are stranded at the present time, although several development proposals are under consideration.

A total of 83 exploration wells have tested prospects in the Federal waters offshore Alaska since 1976. Exploration results have been disappointing, and the few significant oil and gas discoveries made in the Arctic remain undeveloped due to high capital costs and uncertain prices. Two offshore oil fields, Liberty and Northstar, will begin production in 2001-2003, but the associated gas will be used for lease operations. The Burger well, located on the Chukchi shelf 360 miles west of Prudhoe Bay, penetrated the largest gas pool found to date in the Alaska Federal offshore. However, Burger is located in a formidable setting far from existing infrastructure and is uneconomic to develop with current technology and price conditions.

Most (82%) of the 190.99 tcf of undiscovered natural gas resources forecast for Alaska and the Alaska Federal offshore occur in the Arctic. If the undiscovered gas resources in the Mackenzie delta (53 tcf) are added to those onshore in northern Alaska (63.5 tcf), and Federal submerged lands on the Beaufort (32.07 tcf) and Chukchi shelves (60.11 tcf), **the Arctic regional undiscovered gas potential totals 208.68 tcf.** This volume is equal to 40% of the total U.S. undiscovered conventional gas resource base (526 tcf). Arctic Alaska and the Mackenzie delta seem destined to someday become major producing areas for natural gas. However, a significant fraction of the undiscovered gas resources could occur in small, remote accumulations that may never be profitable to develop.

Across Alaska and the Alaska offshore, unconventional sources like gas hydrates and coal bed methane are estimated to contain up to 170,000 tcf of natural gas in place. Most of this hypothetical natural gas resource is contained in gas hydrates that are located far offshore in water depths exceeding 300 m and will remain inaccessible for the foreseeable future. However, 37 to 44 tcf of gas are estimated to occur in sub-permafrost gas hydrates in and around the Prudhoe Bay-area developed oil fields and might be exploited on an experimental basis once a gas transportation infrastructure is installed.

Resource assessments in 1995 and 2000 estimated the total undiscovered conventionally recoverable gas resource base and the fractions of that gas resource base that could be profitable to develop. Several Alaska provinces, onshore and offshore, were found to potentially hold economic gas resources at landed market prices of $2.11 and $3.5?/mcf (constant

$2000, equivalent to oil at $18/bbl and $30/bbl). At $2.11/mcf paid at a variety of markets, 6.172 tcf gas might be economic to develop across Alaska (5.14 tcf for offshore alone). At $3.52/mcf, 12.23 tcf gas might be economic to develop (8.67 tcf for offshore alone). The undiscovered economically recoverable gas resources (12.230 tcf) represent only 6% of the 190.99 tcf total undiscovered conventionally recoverable gas resource base for all of Alaska.

At high gas prices like those witnessed in the U.S. in recent months, economic recoverability improves for most offshore Alaska provinces. At a gas price of $6/mcf (constant $2000) delivered to a variety of markets, the Alaska Federal offshore could contain a total of 35.78 tcf of undiscovered economically recoverable gas. At $6.00/mcf, 20.0 tcf could be economic to co-produce with oil resources on the Chukchi shelf and deliver as LNG to Pacific Rim markets. Associated gas resources produced through new offshore oil fields on the Beaufort shelf and delivered to a plantgate at Prudhoe Bay become economic at prices of $1.00/mcf or higher, with 4.66 tcf economically recoverable at $6/mcf. If produced gas is delivered to a hypothetical plantgate at Kivalina—the port for the Red Dog mining operation—Hope basin could have economically recoverable gas resources of 2.27 tcf at $6/mcf. Not all basins invite economic development. Even at a $6.00/mcf price, most of the Bering Sea provinces remain uneconomic. Gas prices of $10/mcf to $15/mcf would be required to support significant economic gas development in Norton basin, St. George basin, or Navarin basin. At $6/mcf, North Aleutian basin in southern Bering Sea offers 5.90 tcf of undiscovered, economically recoverable gas. However, North Aleutian basin is under a moratorium forbidding oil and gas leasing, exploration, or development until year 2012. At $6/mcf delivered to the local gas transmission pipeline network in Cook Inlet region, the Lower Cook Inlet (Federal waters) could have 1.24 tcf of undiscovered economically recoverable gas. At $6/mcf delivered as LNG to Japan, the Shumagin-Kodiak shelf and Gulf of Alaska shelf could have 1.40 tcf and 0.31 tcf, respectively, of undiscovered economically recoverable gas.

The Prudhoe Bay-area gas reserves (26 tcf) are the key assets that will drive near-term strategic decisions about how to transport and market stranded natural gas from northern Alaska. Since 1977, natural gas recovered during oil production has been re-injected to increase oil recovery or used as fuel for production facilities. Over 35 tcf of gas has already been produced and re-injected or consumed at the Prudhoe Bay area fields. In 1999, gross gas production from the North Slope oil fields was 3.15 tcf (8.63 bcfpd) of which 93 percent was re-injected.

The 5.8 billion barrels oil reserves remaining (as of late 1999) in the Prudhoe Bay area fields (originally17 billion barrels) are now only a little larger than the remaining gas reserves—an energy asset equivalent to 4.6 billion barrels of oil. Northern Alaska oil production is declining precipitously and there is some concern about when production will fall below the minimum required to profitably operate the Trans Alaska oil pipeline (TAPS). As the Prudhoe Bay area oil fields begin to approach depletion, daily gas production is increasing and gas-handling capacities may someday further constrain oil production. Expansion of gas-handling facilities may be required to allow oil production to continue at optimum rates, or, at least at rates sufficient for TAPS operations. Alternatively, gas sales out of Prudhoe Bay could help avoid capital outlays for new gas-handling equipment. Limited gas sales could begin at any time from the Prudhoe

Bay-area fields without affecting recovery of the remaining 5.8 billion barrels of oil reserves. Major gas sales could begin after year 2015 with no harm to ultimate oil recoveries, and the impacts of earlier gas sales could possibly be mitigated through measures like increased waterflood and carbon dioxide re-injection (Meyers, 2000).

At present, three concepts are in the forefront for commercializing the stranded gas resources in northern Alaska and Mackenzie delta:

- ***A New Pipeline Connecting to the Canadian gas pipeline network.*** Build conventional or high-pressure gas pipelines to carry the gas from Prudhoe Bay and Mackenzie delta to northern Alberta or British Columbia, where the new pipeline would join the Canadian pipeline network and supplement ongoing transmission gas exports to the U.S. Pipeline capacities of 2.5 bcfpd (0.9 tcf/yr) or 4.0 bcfpd (1.46 tcf/yr) delivered to the western Canada pipeline network typify most proposals.

- ***Liquefied natural gas (LNG) to Asian Pacific Rim.*** Build a conventional or high-pressure gas pipeline that carries the gas from Prudhoe Bay-area fields to a port in southern Alaska, where the gas is chilled to liquefied natural gas (LNG) and loaded on special LNG tankers for transport to the Asian Pacific Rim or perhaps the U.S. West Coast via return pipeline from hypothetical a port in western Mexico. System throughput for current proposals ranges from 1.5 bcfpd (0.5 tcf/yr) to 2.5 bcfpd (0.9 tcf/yr).

- ***Gas to liquids (GTL) and tankers to U.S. West Coast.*** Build a new facility in the Prudhoe Bay area and use GTL technology to convert natural gas to middle-distillate (diesel-like) liquids. The GTL product could be pumped in segregated batches through the Trans Alaska oil pipeline and then transported by tankers to the U.S. West Coast. A 50,000 bpd (0.5 bcfpd or 0.2 tcf/yr) plant has been promoted by one group, but BP-Amoco, a major owner of the gas at Prudhoe Bay, is presently building a small experimental GTL plant at Nikiski ın Cook Inlet, Alaska (operational in 2002).

The original proposal for a gas pipeline through Canada—the Alaska Natural Gas Transportation System (ANGTS) and now sometimes called the "Highway Route"-- followed the Dalton Highway from Prudhoe Bay to Fairbanks and then followed the Alaska Highway to central Alberta. A 1995 study published by the ANGTS group (abstr. by Thomas and others, 1996, p. 3-4) estimated that delivery costs for their $16.7 billion project would range from US$2.82/mcf to US$4.17/mcf in $1995 (or $3.29/mcf to $4.86/mcf in $2000). A similar "highway" gas pipeline project now being studied by the Prudhoe Bay gas owners would cost US$10 billion (2.5 bcfpd line) to US$12 billion (4.0 bcfpd line) and could profitably deliver gas to Chicago for $3.50/mcf (Meyers, 2000). Chicago city gate prices were approximately $8/mcf in January 2001. U.S. domestic natural gas demand, now at 22 tcf/year, is predicted to rise to 35.57 tcf/year by year 2020 (AEO, 2000, tbl. A1), thus ensuring a future of strong demand for any gas that can be profitably brought to the U.S. market from northern Alaska or Canada.

Alaska has the only LNG export operation in the U.S. Small amounts of LNG (0.06 tcf/year) from gas fields in Cook Inlet have been sent to Yokohama, Japan since 1971. A much grander LNG export model, shipping perhaps 0.9 tcf/year, has been proposed by Yukon Pacific Corporation for moving gas from northern Alaska into the Asian Pacific Rim and U.S. West Coast markets. The LNG project at the largest scale would require construction of a new gas conditioning plant at Prudhoe Bay, an 800-mile gas pipeline, a new LNG plant and marine terminal at Valdez in southern Alaska, and a new LNG tanker fleet, all for approximately $12.76 billion ($2000). No economic studies of the most recent LNG proposals are publicly available. A 1995 study by Thomas and others (1996) using a 0.85 tcf/yr LNG project costing $16.03 billion ($1995) found that a flat world oil price of $19.36/bbl ($1995) was required for the LNG project to economically "breakeven" (NPV_{10}=0). The AEO (2000) *Reference Case* forecasts that world oil will reach this price in year 2015. A $19.93 world oil price is approximately equivalent to an LNG price of $3.77/mcf (in September 2000, Cook Inlet LNG shipments to Japan were receiving $4.33/mcf). A 1999 DOE update study by Robertson (1999) found the LNG project to be unprofitable (NPV_{10}= — $2,402 billion), in fact providing the poorest return of all marketing concepts modeled by that study. An LNG export volume of 0.9 tcf/year would be equal to a very large fraction (28%) of the entire 1998 Asian Pacific rim LNG market (3.225 tcf/year). The chief risk element of the LNG proposals is that such large exports might flood the principal market and cause a price collapse. Because of market risk and capital cost considerations, plans for smaller initial LNG-based projects (output as low as 0.46 tcf/year, costing $8.2 billion to construct) have also been proposed, but the economics of the smaller scale projects are not publicly available.

Gas-to-liquids (GTL) technology forms an attractive option because it can supplement the throughput of the Trans Alaska oil pipeline (TAPS) and perhaps extend the operating life of this critically important oil transportation system decades into the future. The addition of GTL liquids to the oil transportation system would also moderate per-barrel oil pipeline tariffs, which are expected to rise in the future as the volume of pipeline throughput falls. The continued existence of the oil pipeline and a lowering of future oil pipeline tariffs are critical to the economics of future development of smaller, undiscovered oil fields in northern Alaska and the Arctic Federal offshore. A 1995 study by Thomas and others (1996) of a hypothetical 300,000 bpd (3 bcfpd or 1.1 tcf/yr) northern Alaska GTL project costing $13 billion found that a "breakeven" (NPV_{10}=0) flat world oil price of $19.94/bbl ($1995) was required for economic viability. The AEO (2000) *Reference Case* forecasts that world oil prices will not reach this price until after year 2020. However, in September 2000, the actual world oil price averaged $31.10/bbl (or $26.69/bbl in $1995). GTL, or at least its modern component processes, involve relatively new technologies that are only now entering commercial applications. A recent study of northern Alaska GTL economics by Robertson (1999) revealed that incremental construction of several small GTL facilities allowed for "learning"—resulting in cost reductions to facilities built later in the life of the project. This "incremental" GTL model provided the most favorable economic outcome. Future market demand for GTL product is expected to be robust. The chemical conversion of natural gas to liquid hydrocarbons creates an essentially refined product that is free of polluting agents and that as a transportation fuel can command premium market prices, particularly on the U.S. West Coast, where ultra-clean motor fuels will be mandated.

The gas transportation system that is eventually constructed to take Prudhoe Bay gas reserves to market will be scaled to the known reserve volumes. For this reason, the gas transportation system will be completely filled for years after start up with production from Prudhoe-area gas fields. Newly-discovered gas will have to await declines in the area production levels such that excess capacity (unfilled space) develops in the gas transportation system. If we assume that a gas pipeline to Prudhoe Bay is operational by year 200[illegible] and that excess capacity becomes available after 90 percent depletion of known reserves, the earliest shipments of newly-discovered gas would be in year 2015 for an 8 bcfpd line, or year 2023 for a 4 bcfpd line, or year 2033 for a 2.5 bcfpd line. An 8 bcfpd gas pipeline has not been proposed, but this is the present rate of gas recycling in the Prudhoe-area fields. There are currently proposals for the two smaller pipelines, of which the 4 bcfpd pipeline seems to be favored. Of course, if *substantial* new gas discoveries justified the additional expense, increasing pipeline pressure (adding compression equipment) could increase pipeline capacity at any time.

Northern Alaska and its contiguous continental shelves are richly endowed with natural gas. However, finding and developing any significant fraction of this undiscovered resource will prove very costly. At the current slow pace of leasing, exploration, and development, a significant fraction of the undiscovered natural gas endowment of northern Alaska could remain unavailable to meet market demands for many decades.

Because of the long lead-time required for major construction projects, the time may now be at hand for decisions about how to export the stranded natural gas reserves of northern Alaska and northwestern Canada. These decisions will lead to construction of a huge natural gas marketing infrastructure costing billions of dollars. Gas production strategies and new infrastructure will determine the character of oil and gas development in northern Alaska and northwestern Canada for many decades to come.

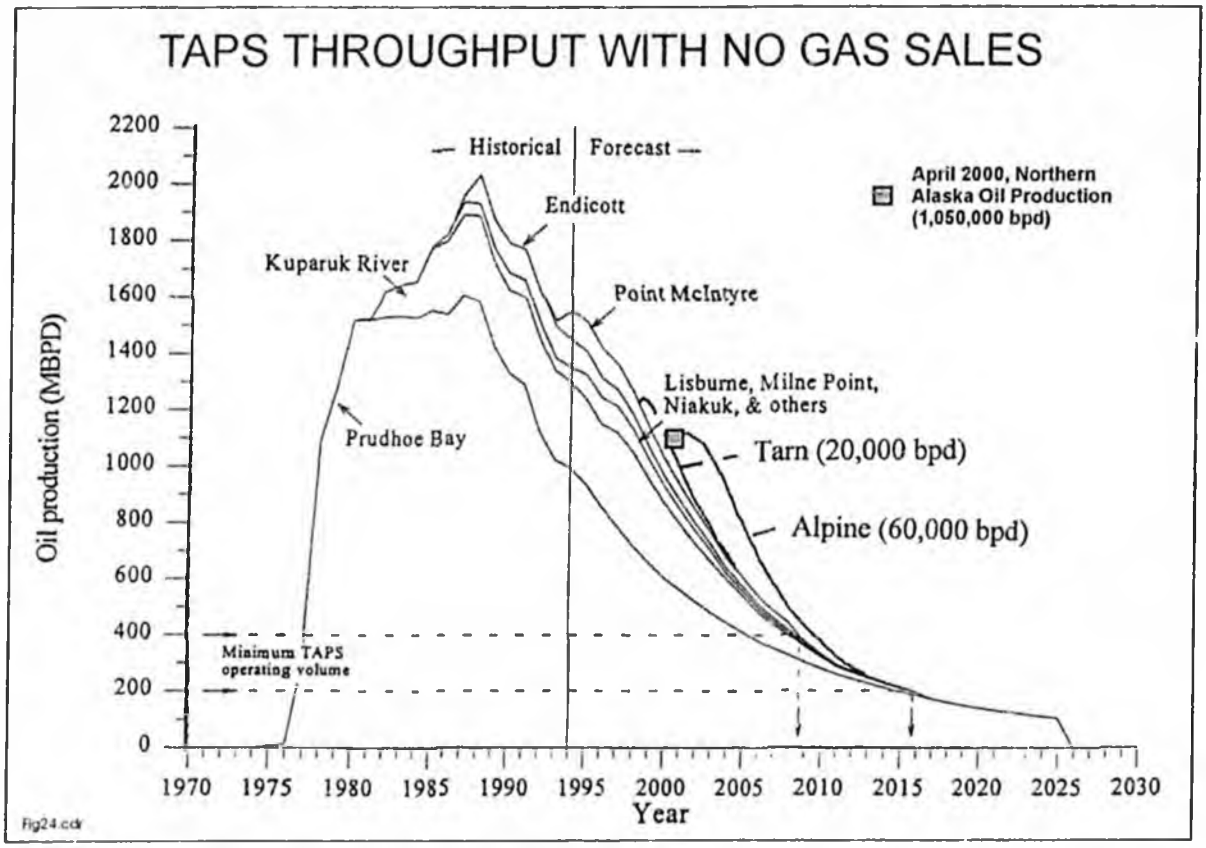


Figure 24: Production decline projections for northern Alaska producing fields in Prudhoe Bay area. Contributions from new fields at Tarn and Alpine have been added as sketches based on estimates for maximum production rates. These new fields, although significant, will not materially prolong the economic life of TAPS, projected to end when throughput falls to some level between 400,000 bpd (year 2009) and 200,000 bpd (year 2016). Diagram modified after Thomas and others (1996, fig. 2).

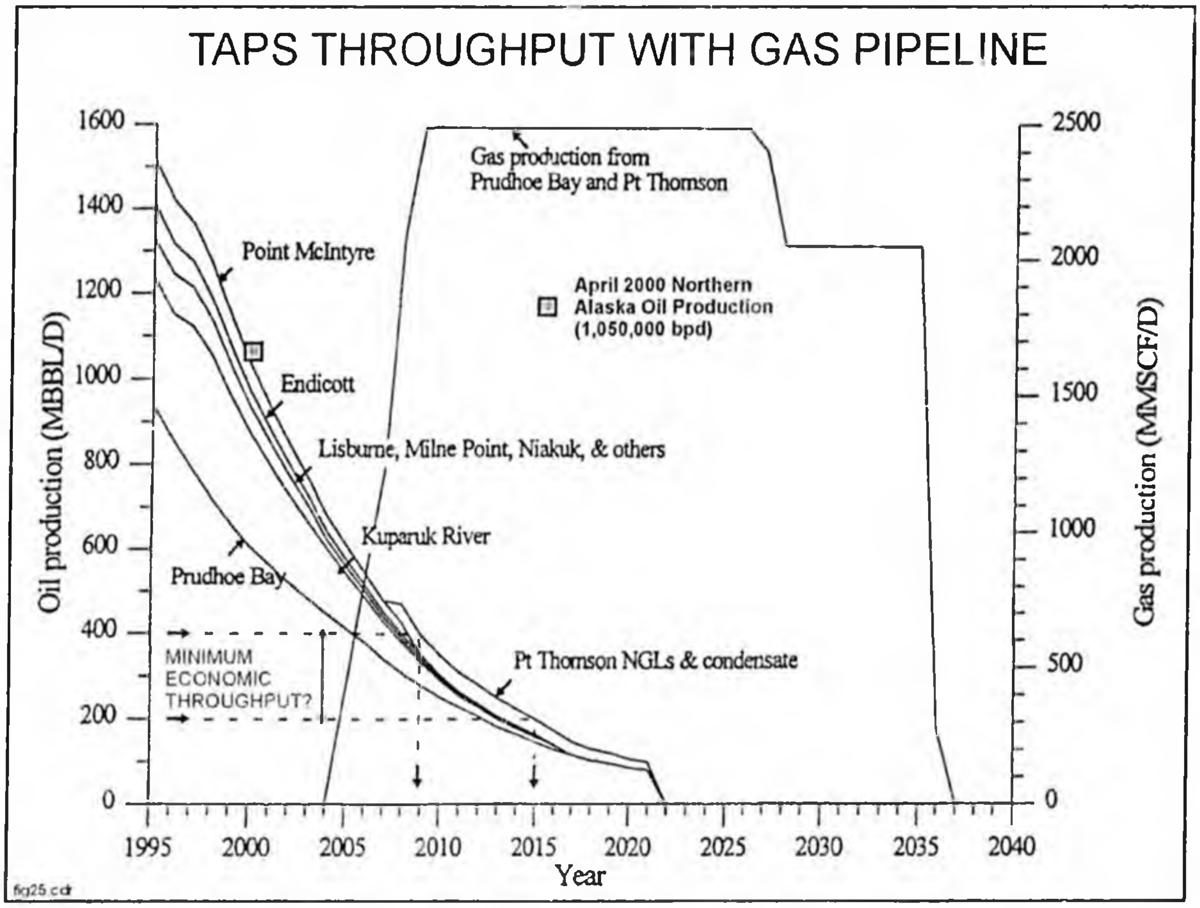


Figure 25: Model for TAPS (oil pipeline) throughput if gas is conveyed through a separate gas pipeline for export from southern Alaska. The economic life of TAPS is shortened about 1 year (to year 2015) at the 200,000 bpd threshold (compare to fig. 24). Diagram adapted from Thomas and others (1996, fig. 2.8).

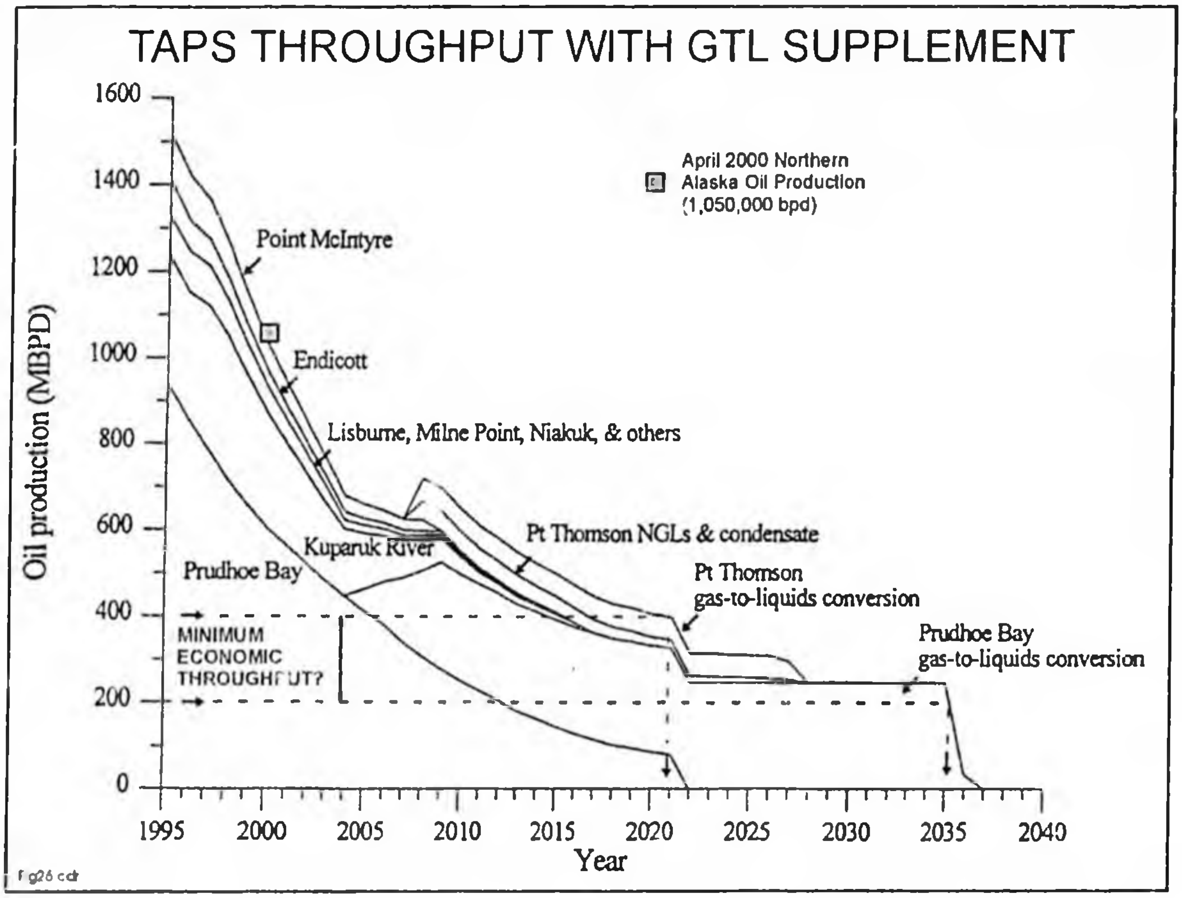


Figure 26: Model for TAPS (oil pipeline) throughput if gas is exported as GTL liquid conversion product through the TAPS line to the tanker facilities at Valdez. The economic life of TAPS is extended by about 20 years over other gas export options at the 200,000 bpd throughput threshold. Diagram from Thomas and others (1996, fig. 2.9).

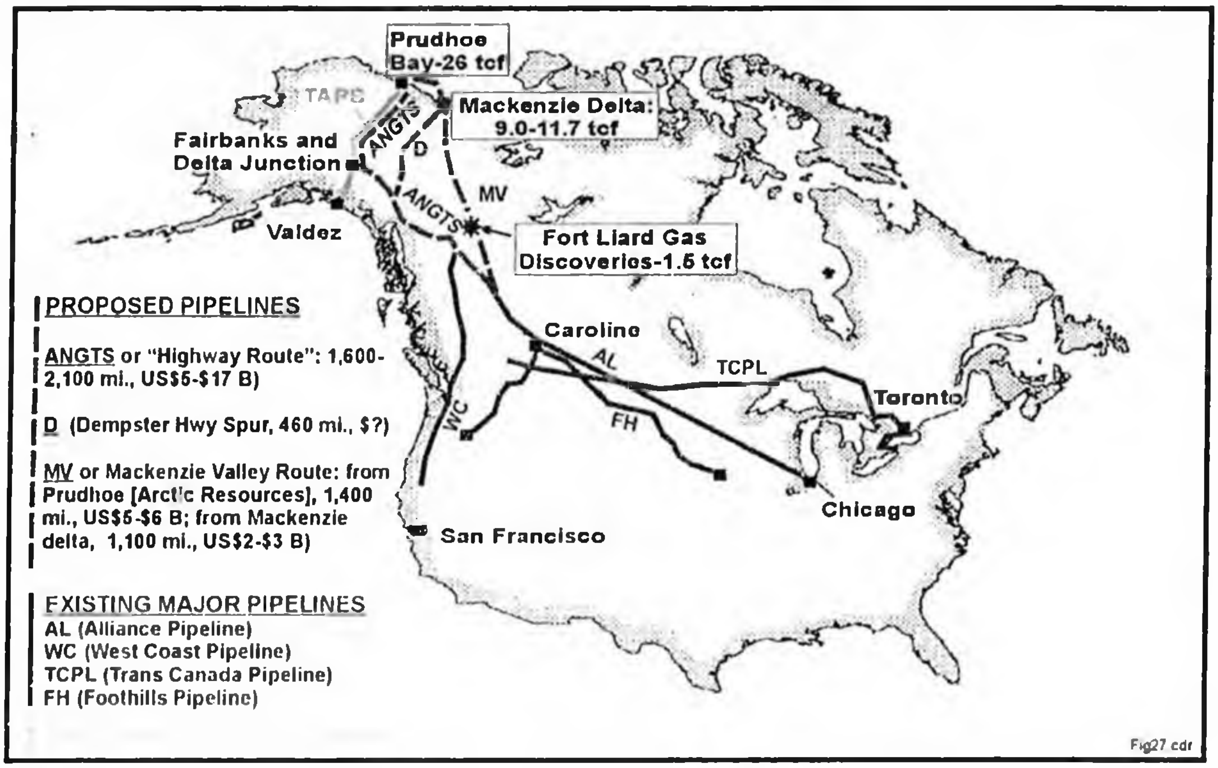


Figure 27: Routes of proposed "ANGTS" (Alaska Natural Gas Transportation System, now referred to as the "highway route"), "MV" (Mackenzie Valley), and "D" (Dempster highway spur) gas pipelines proposed for transportation of natural gas from Prudhoe Bay (26 tcf) and Mackenzie delta (9 to 11.7 tcf) fields to existing pipelines in northern Alberta and British Columbia, Canada. Recent gas discoveries in the Fort Liard area (1.5 tcf and growing) will extend the Canadian pipeline network northward toward the Mackenzie delta. The "over the top" route proposed by Arctic Resources Ltd. involves a subsea pipeline from Prudhoe Bay to Mackenzie delta and then a land pipeline southward down the Mackenzie River valley. A stand-alone spur line from Mackenzie delta to northern Alberta is also proposed. Map adapted from Attanasi (1995, fig. 1) and Speiss (1999a).

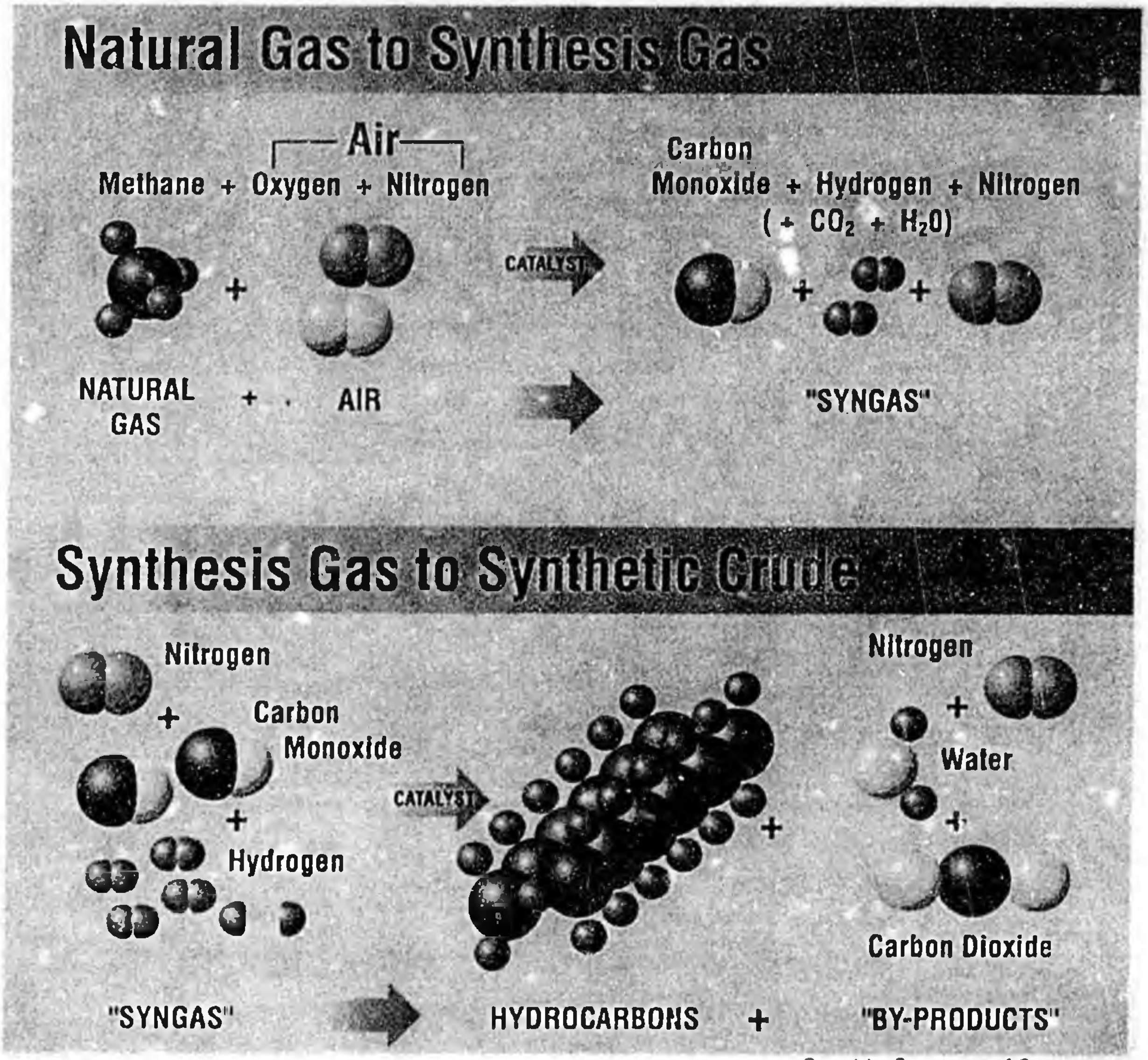


Fig28.cdr

Graphic Courtesy of Syntroleum

Figure 28: ***Gas-to-Liquids, Fischer-Tropsch Process, or "F-T Process".*** **This schematic shows the basic steps in converting methane or natural gas into synthetic liquids. First, methane is broken into hydrogen and carbon, the latter united with oxygen to create carbon monoxide. The mix of hydrogen and carbon monoxide is called synthetic gas or "syngas". Second, the carbon monoxide is reacted with hydrogen in the presence of a catalyst to build long hydrocarbon chains consisting of 14 to 20 carbon atoms. Hydrocarbon chains of this length are diesel-type liquids, or "synthetic crude." Other liquid products can be formed, depending upon process design. Diagram created by** ***Syntroleum Corp.*** **and adapted from publication by Nation (1997).**

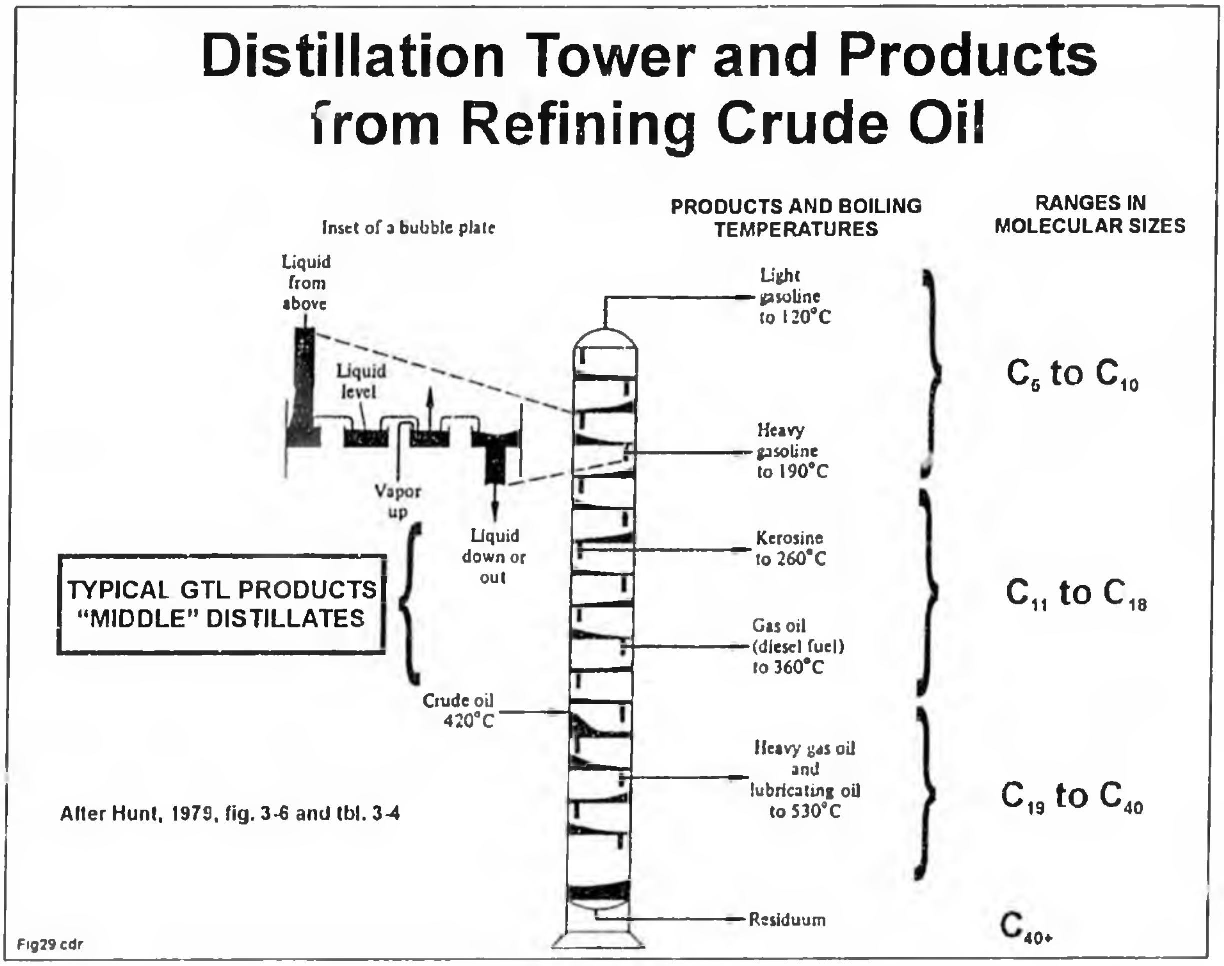


Figure 29: Sketch of distillation tower and products from refining of crude oil. Bubble plates separate liquids on basis of density and molecular size, which controls boiling (vaporization) points. Gas-to-liquids or GTL conversion typically produces fuels in the gasoline to diesel range, corresponding roughly to "middle" (of tower) distillates. Diagram adapted from Hunt (1979, fig. 3-6, with information from his tbl. 3-4).

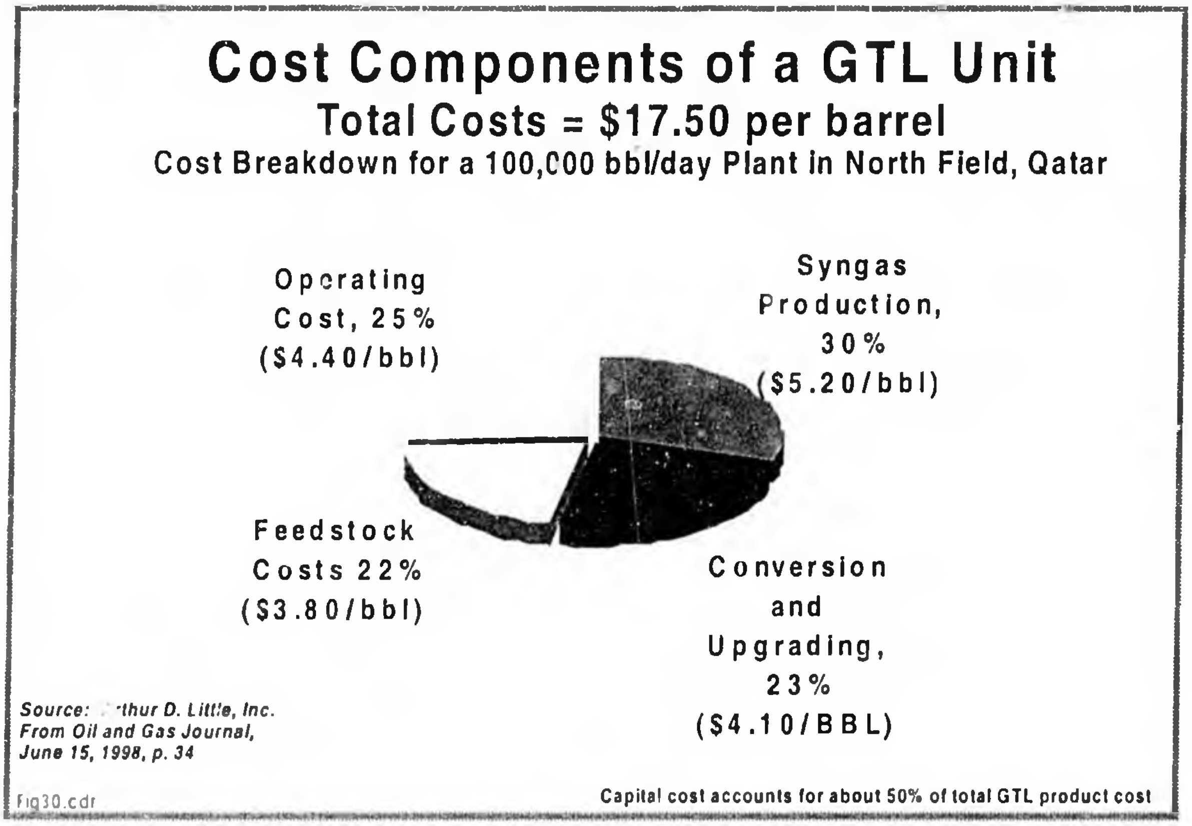


Figure 30: Cost components of a gas-to-liquids facility at output scale of 100,000 b. .rels of product per day, located in Qatar. Feedstock costs of $3.80 per barrel of conversion liquid are approximately equivalent to $0.38/mcf of feedstock gas. Diagram redrawn from O&GJ (1998, p. 34).

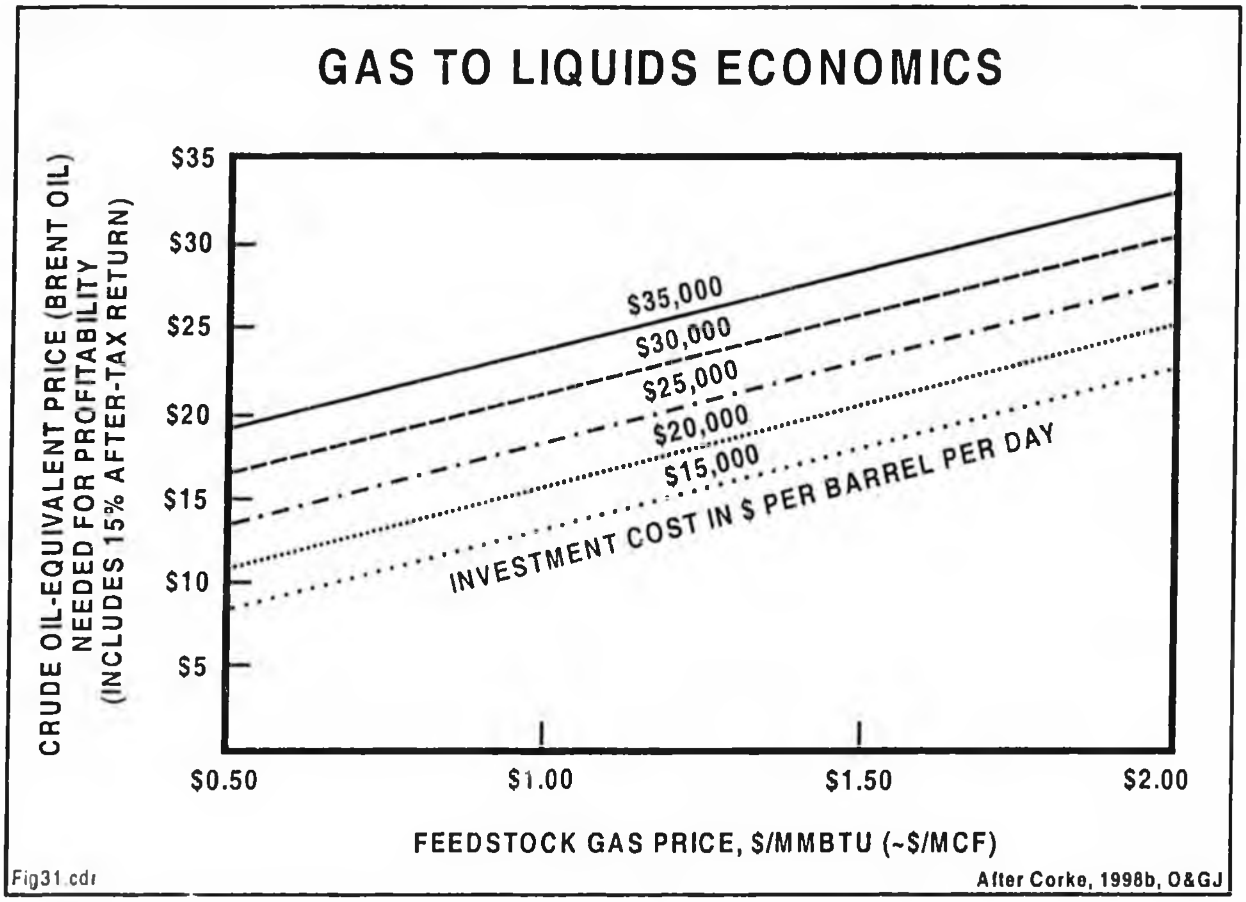


Figure 31: Economics of GTL projects and relationship to feedstock gas costs. $0.50/mcf roughly translates to $5.00 per barrel of liquid GTL product. Investment costs for plant construction are represented in dollars per barrel of daily plant output and are determined by plant scale. Larger plants benefit from economies of sca' and correspond to the lowest investment costs in dollars per barrel per day. A plant that cost $30,000 per barrel per day to construct and using gas costing $1.00/mmbtu will require a Brent oil price (an arbitrarily chosen index) of $21 per barrel to yield a 15% after-tax R.O.I. Diagram redrawn after Corke (1998b, fig. 4) for dry gas project with no revenues from condensate co-production.

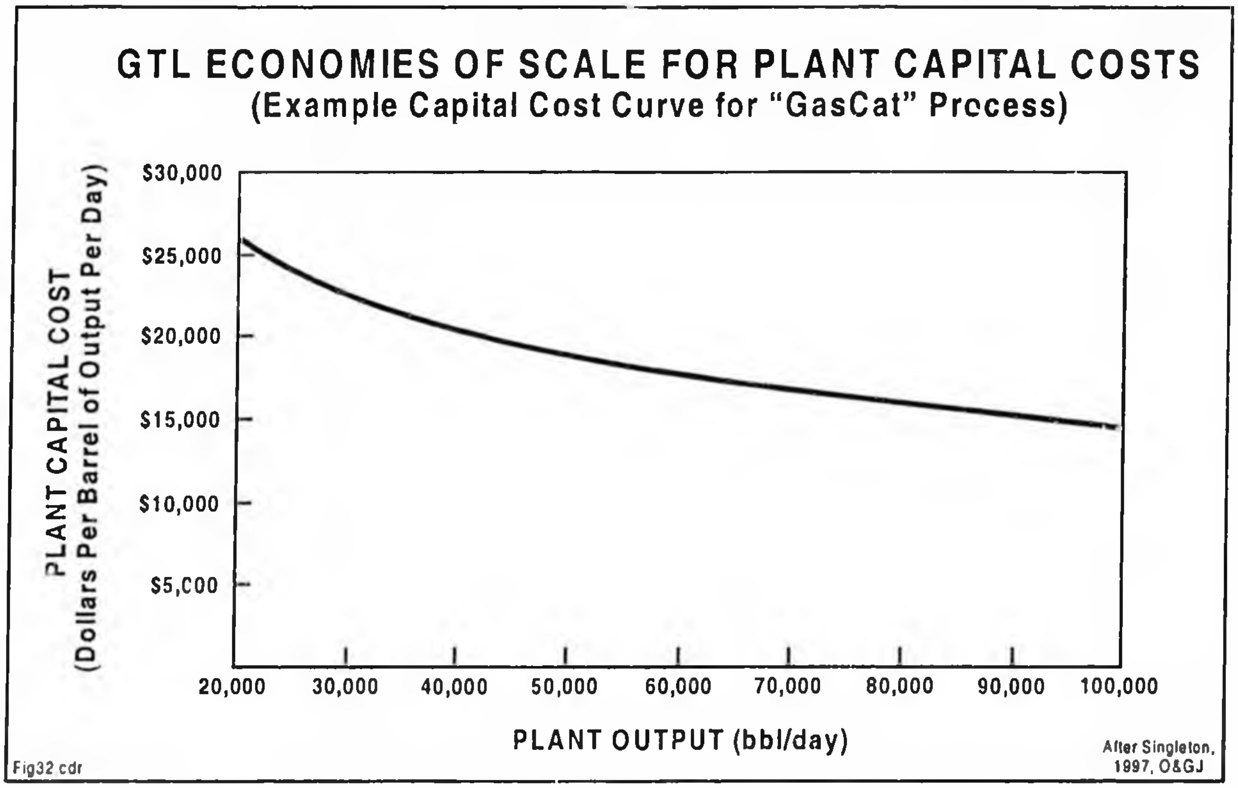


Figure 32: Example from "GasCat" process showing how larger GTL plants benefit from economy of scale and can produce liquids from gas more cheaply. For example, capital costs for this type of GTL plant, when designed for an output capacity of 100,000 barrels of liquid product per day, are only $15,000/barrel/day, nearly half the costs of plants with capacities smaller than 20,000 barrels per day. Diagram redrawn from Singleton (1997, fig. 3).

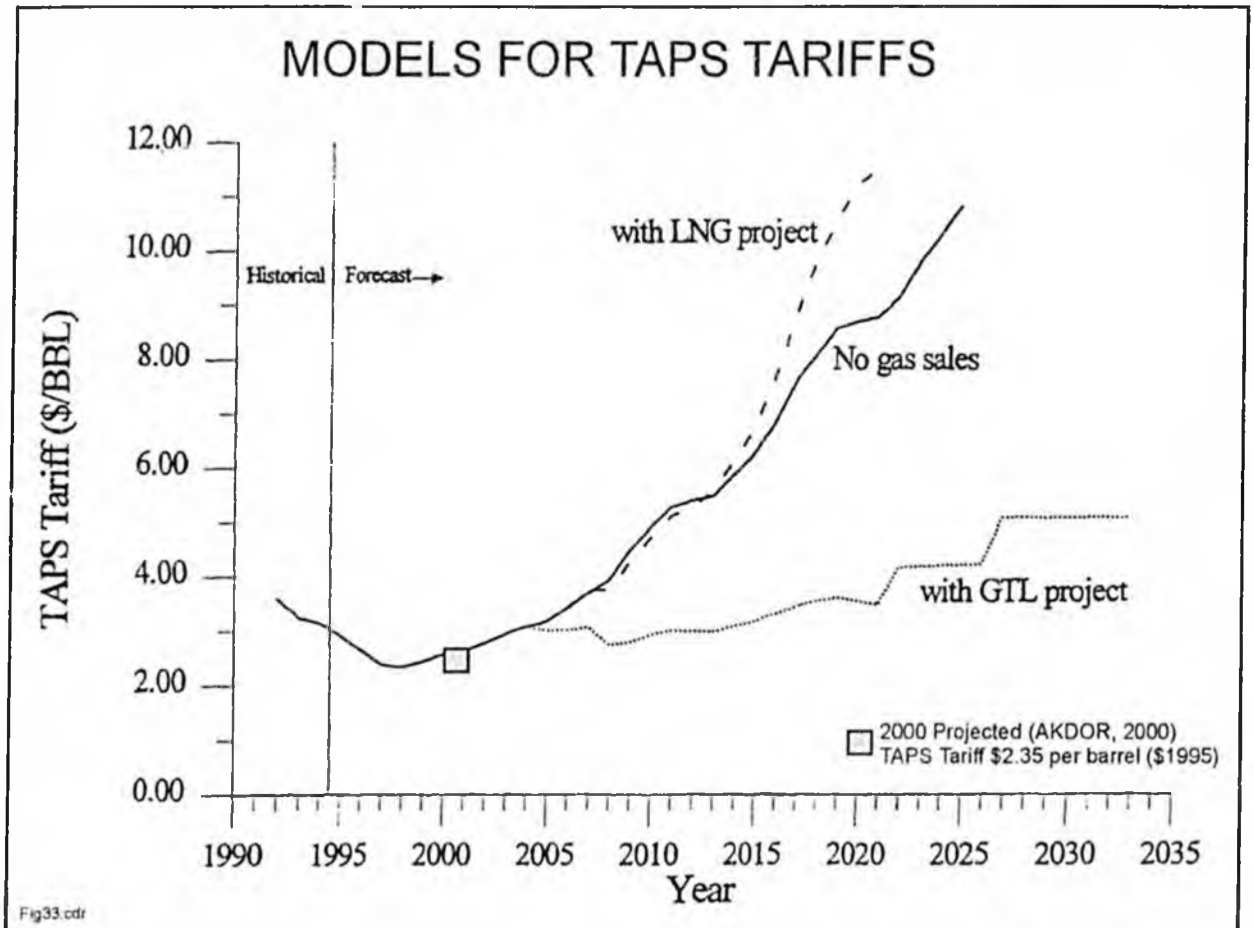


Figure 33: Trans-Alaska oil pipeline (TAPS) tariff projections to year 2035, shown in $1995. A gas-to-liquids (GTL) project will add to pipeline throughput and will moderate future tariff increases, potentially allowing small future oil (and gas?) discoveries to be economic to produce. A liquified-natural gas (LNG) project requiring a separate gas pipeline will shorten the economic life of TAPS and may result in high tariffs for TAPS which might make future small discoveries uneconomic to develop. Diagram from Thomas and others (1996, fig. B.3). Current tariff from projection for 2000 in AKDOR (2000, tbl. 15) indicating $2.74 per barrel (nominal; $2.35 in $1995).

August 1996

Idaho National Engineering Laboratory

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INEL-96/0322

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Published August 1996

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Prepared for the
U.S. Department of Energy
Office of Fossil Energy
Under DOE Idaho Operations Office
Contract DE-AC07-94ID13223

ECONOMICS OF ALASKA NORTH SLOPE GAS UTILIZATION OPTIONS

ABSTRACT

The recoverable natural gas available for sale in the developed and known undeveloped fields on the Alaskan North Slope (ANS) total about 26 trillion cubic feet (TCF), including 22 TCF in the Prudhoe Bay Unit (PBU) and 3 TCF in the undeveloped Point Thomson Unit (PTU). No significant commercial use has been made of this large natural gas resource because there are no facilities in place to transport this gas to current markets. To date the economics have not been favorable to support development of a gas transportation system. However, with the declining trend in ANS oil production, interest in development of this huge gas resource is rising, making it important for the U.S. Department of Energy, industry, and the State of Alaska to evaluate and assess the options for development of this vast gas resource.

The purpose of this study was to assess whether gas-to-liquids (GTL) conversion technology would be an economic alternative for the development and sale of the large, remote, and currently unmarketable ANS natural gas resource, and to compare the long term economic impact of a GTL conversion option to that of the more frequently discussed natural gas pipeline/liquefied natural gas (LNG) option. The major components of the study are: an assessment of the ANS oil and gas resources; an analysis of conversion and transportation options; a review of natural gas, LNG, and selected oil product markets; and an economic analysis of the LNG and GTL gas sales options based on publicly available input needed for assumptions of the economic variables. Uncertainties in assumptions are evaluated by determining the sensitivity of project economics to changes in baseline economic variables.

The projects evaluated assume gas sales from PBU start in 2005 and reach a peak rate of 2.05 billion cubic feet per day (BCFPD) in 2009, and sales from PTU starting in 2008 at 0.44 BCFPD, for a combined peak rate of 2.49 BCFPD. This results in sales of 17 million metric tonnes per year of LNG, or 300 thousand barrels per day of a GTL liquid hydrocarbon product compatible with the North Slope crude oil and transportable in the Trans Alaska Pipeline System (TAPS). The total investment (1995$) for the LNG option is $17 billion and $13 billion for the GTL option. Both include investments necessary to develop PTU.

The results of the economic evaluations, prepared using the Energy Information Administration 1995 Reference Oil Price forecast that anticipates real oil price growth of about 2.4%/yr, indicate that both LNG and GTL project options will be profitable (10% rate of return on investment) for [illegible] gas project developers. In addition, economic returns to the PBU and PTU gas producing units will be higher than they would be without gas sales. Also, of the two options, the GTL route assures minimum flow rates needed to extend TAPS operability for about 20 years after existing North Slope oil-producing reservoirs are largely depleted.

In summary, both the LNG and the GTL options are economically promising and warrant consideration in industry and government decision-making. However, at this point in time, it is not possible to conclude that one option is significantly better than the other. Focussed follow-up investigations to this study would be of value to industry and State of Alaska decision makers, and are recommended.

ECONOMICS OF ALASKA NORTH SLOPE GAS UTILIZATION OPTIONS

EXECUTIVE SUMMARY

Introduction

The technically recoverable conventional natural gas resources in the developed and known undeveloped oil and gas fields on the Alaska North Slope (ANS) total about 38 TCF. No significant commercial use has yet been made of this large natural gas resource because there are no facilities in place to transport this gas to current markets, which are outside of the North Slope. To date the economics have not been favorable to support development of a gas transportation system. In addition to the known gas resources, the U.S. Geological Survey's (USGS) most recently published estimate of technically recoverable conventional natural gas resources in undiscovered fields in Northern Alaska has a mean value of 64 TCF (USGS, 1995).

Figure 1 is a map showing the known oil and gas accumulations and selected dry holes and suspended wells on the North Slope. Although discoveries of oil and gas have been made across Northern Alaska, the only development that has occurred is around the super giant Prudhoe Bay field. It is unlikely that any of the other North Slope fields would have been developed without facility cost-sharing made possible by the development of the Prudhoe Bay infrastructure and the construction of the Trans Alaska Pipeline System (TAPS).

About 26 TCF of the 38 TCF of technically recoverable gas is estimated to be available for sale. The balance will be consumed in oil and gas production operations on the North Slope. Although, there has been a high level of interest in developing a capability to bring the huge North Slope natural gas resource to market since the discovery of the Prudhoe Bay field, the urgency to develop the capability to sell the large, currently unmarketable, North Slope gas resources has increased in recent years because of the steep decline in North Slope oil production. ANS production has accounted for almost 25% of the daily U.S. domestically produced oil since production was initiated from the Prudhoe Bay field in 1977. As shown in Figure 2, North Slope oil production peaked in 1988 at 2.0 million barrels per day, declined to 1.5 million barrels per day in 1994, and will continue to decline, reaching about 200 million barrels per day by about 2015 unless large discoveries and developments are brought on line before then. North Slope oil production is dominated by the Prudhoe Bay field, which began to decline 1988. Continued decline of Prudhoe Bay oil production and its ultimate oil depletion is inevitable. Prudhoe Bay and Point Thomson (a smaller, undeveloped gas/gas condensate field 50 miles east of Prudhoe Bay) contain about 25 TCF of the 26 TCF

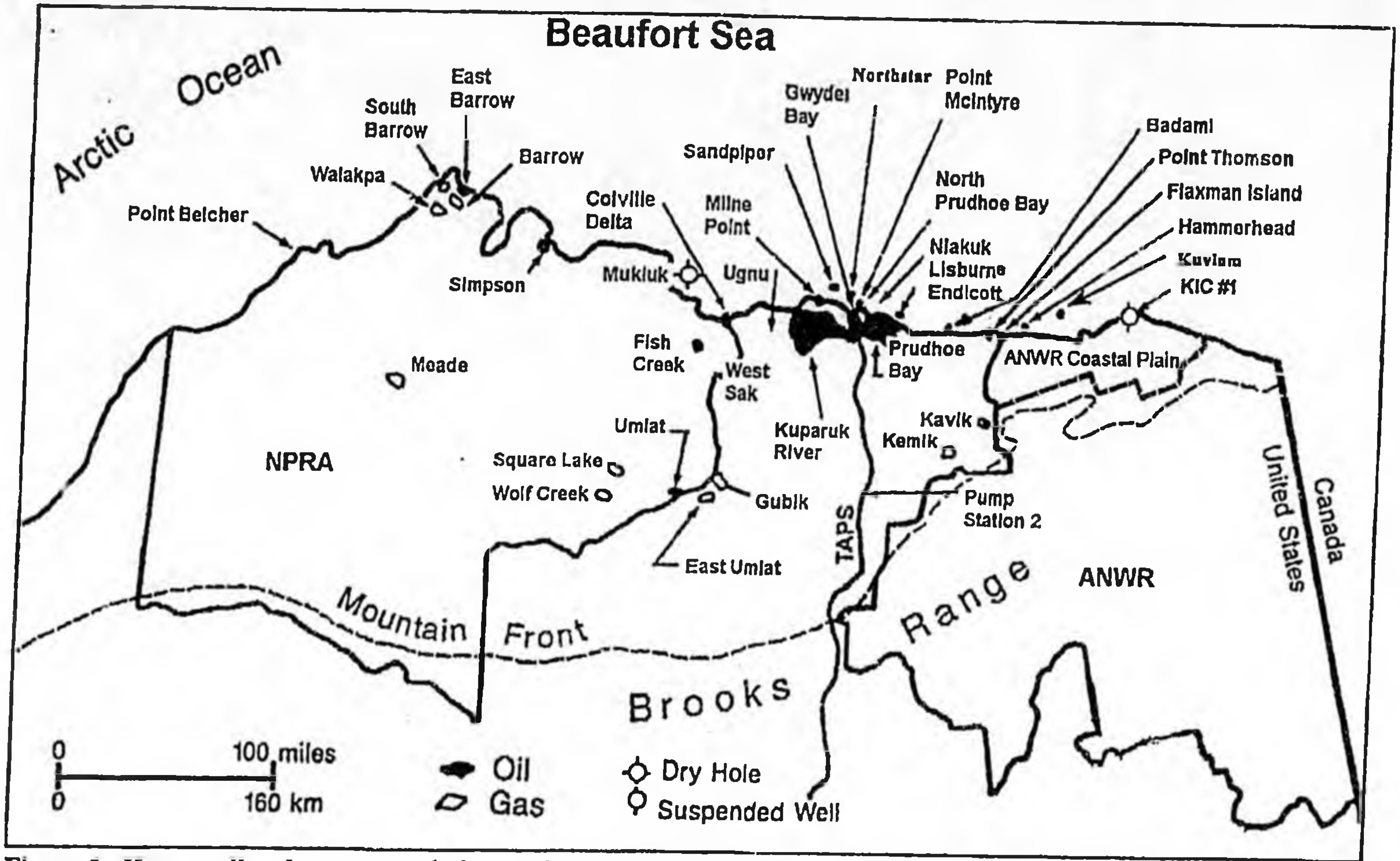

Figure 1. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope Alaska (DOE, 1991, ADNR, 1991a).

of the estimated recoverable natural gas discovered on the North Slope. This is a highly significant resource (over 4 billion barrels of oil equivalent) addition to the estimated remaining recoverable reserves of about 6 billion barrels (as of January 1, 1995) from producing North Slope fields.

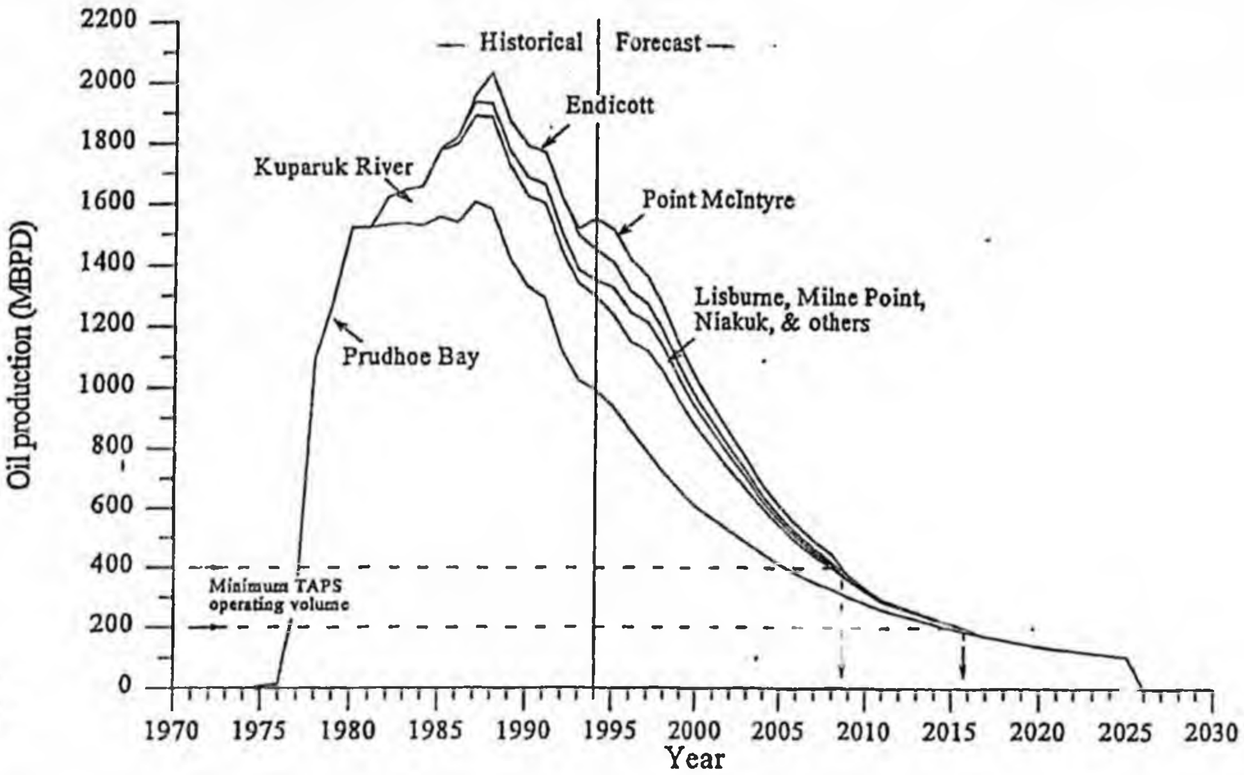

Figure 2. The Alaska North Slope historical production and production forecast at the Energy Information Administration (EIA) Reference Oil Price (economically recoverable oil).

The dashed lines at the bottom of **Figure 2** indicate the currently estimated range of the minimum liquid throughput rate for continued TAPS operation, which illustrates the looming potential of a shutdown of TAPS because of ANS production dropping to a minimum throughput rate for the pipeline in the 2009 to 2016 time frame. Such a shut down could result in the loss of as much as 1 billion barrels economically producible ANS reserves. The intersection of the ANS oil production trend and the pipeline minimum throughput range, coupled with the long lead time of 5 to 10 years required to bring major ANS development projects on line, make clear the urgency of evaluating the technical options that could influence the future of ANS oil production, as well as gas production.

To date, the only use of the gas that is currently produced at Prudhoe Bay with the crude oil, aside from local ANS use and the extraction of NGLs for sale with the crude oil, has been for reinjection to enhance recovery of crude oil. The use of the gas for improved oil recovery has been very successful as demonstrated by the increase in reserves for the Prudhoe Bay Unit (PBU) from the early estimates of under 10 billion barrels oil (BBO) to the current estimate of 13 BEO (56% of the original oil in place). Thus, the natural gas reinjected into the reservoirs has had significant interim value to the producers in improving production rates and ultimate oil recovery. However, the use of Prudhoe Bay gas for oil recovery is becoming less important and less valuable with the decline in oil production, which increases the urgency to develop the capability to market the gas, thereby extending the life of North Slope operations and continuing the generation of employment and revenue for the State of Alaska and the nation.

The possibility of exporting the gas via a pipeline from the North Slope to a Valdez LNG plant, followed by tanker shipment to Asian buyers, has long been suggested and studied as an ANS gas sales option. This study, however, sought to assess the economic and technical feasibility of a second option, based on newer technology than that well-established for LNG. This option involves the chemical conversion of gas to a distillate-type hydrocarbon liquid that could be transported and sold with continuing ANS crude oil production via the existing TAPS and tanker fleet. With the gas-to-liquids (GTL) option, a gas pipeline would not have to be built and additional volumes of hydrocarbon liquids would be available for transport through TAPS. This added liquid volume would assist in maintaining the viability of TAPS and result in lower tariffs for all liquids transported in TAPS. Lower TAPS tariffs return a higher net liquid sales price for all fields and projects, those currently producing and future developments.

Purpose

The primary purpose of this study was to provide a technical and economic evaluation of the feasibility of using technology for chemical conversion of natural gas-to-hydrocarbon liquids for bringing the large, remote, and currently unmarketable ANS natural gas resource to market. However, because of the long-standing interest and high visibility of the LNG option, which involves construction of a natural gas pipeline to an all-weather Alaska port and construction of a new plant for physical conversion of gas to LNG, with subsequent tanker transport and sale of the LNG to Asian buyers, it was apparent that an examination of how the gas-to-liquids (GTL) conversion option compares to the LNG option was necessary. The objective of these comparisons was to provide a basis for discussion and evaluation of the interrelated, complex issues and concerns involved in the development and sale of the ANS gas resource.

The results of the evaluations and economic comparisons are intended to provide information to assist industry, the State of Alaska, and the federal government in making a better assessment of how to realize the maximum benefit from the ANS oil and gas resources.

The report is organized as follows:

- **Section 1.** Introduction describing the issues and problems associated with major gas sales from the ANS.
- **Section 2.** Assessment of the ANS oil and gas resources.
- **Section 3.** Discussion of the gas resource utilization options and technologies for physical conversion of natural gas to LNG and chemical conversion to hydrocarbon liquids.
- **Section 4.** Overview of LNG and GTL product markets.
- **Section 5.** Description of the economic analysis framework, the economic assumptions; and results of the baseline economic analysis, and the sensitivity analysis.
- **Section 6.** Conclusions and recommendations for follow-up analyses by interested parties.
- **Appendix A.** Descriptions of ANS fields currently producing and fields with development potential, and forecasts of production, investments, and operating costs.
- **Appendix B.** Description of the procedures and input variables used in the economic analysis.
- **Appendix C.** Description of the economic model.
- **Appendix D.** Tables of values from the model runs.
- **Appendix E.** Bibliography.

The following sections contain summaries of the approach, the economic variables used, the economic results, and the conclusions and recommendations.

Assessment Approach

The first step was to develop an updated outlook for prospective oil production from producing ANS reservoirs. These updated forecasts provide the basis for assessing the economic effects of major gas sales options on future ANS oil production and were necessary before the feasibility of the GTL option could be evaluated and compared with the LNG option. Prospective gas conversion technology was then examined for both the more established physical conversion to LNG, and the less well established GTL chemical conversion to liquid hydrocarbons. This examination included not only the state-of-the-art GTL technology but also included the most promising technology advancements known to DOE researchers that conceivably could have application on the North Slope. In spite of proponent optimism that such cost-cutting technology could be ready for application on a large scale by the time of decision making on ANS gas sales, about 4 to 7 years (consistent with investment lead time requirements and gas owner indications that the window of opportunity for major gas sales will be after 2005), the more conservative state-of-the-art LNG and GTL technologies were used as a basis for the evaluations. The GTL technology used for the assessment, assumes Shell's Middle Distillate Synthesis plant that has been operating in Malaysia since 1993. Likewise, the LNG option for gas sales assumes LNG conversion technology as planned by Yukon Pacific Corporation.

The projects and options were evaluated using a standard discounted cash flow analysis. The results were presented in terms of net present value using a discount rate of 10% (NPV_{10}). The NPV_{10} captures the sum, in 1995$, of annual revenues less expenses and investments, adjusted for a discount rate that provides a 10% rate of return on investment. The NPV_{10} analysis required the following input information:

(a) Oil and gas recovery forecasts for all developed and producing ANS oil fields and a forecast for the undeveloped PTU to provide the expected pipeline flow for determination of TAPS tariff schedules.

(b) A determination of the technology that might be employed to transport and convert ANS gas to a transportable and marketable commodity and estimates of the capital and operating costs for each option.

(c) A requirement that the gas sales option (LNG or GTL) provide a reasonable rate of return (assumed to be 10%) as a stand-alone operation before any "gas product net back" could be calculated for payment to the gas producing units.

The evaluations presented did not assume that major new discoveries would be made, but were based on oil (crude oil, condensate, and NGL) production from the currently developed fields coupled with major gas sales from the two principal ANS gas fields, the Prudhoe Bay field and the currently undeveloped Point Thomson field. The two gas sales options were evaluated as stand-alone projects that purchase gas from each of the fields. Finally, the impact on federal, state, and industry revenues for the combined field and gas sales project options were estimated.

Baseline Economic Variables

Baseline assumptions for the key economic variables were:

(a) The EIA 1995 Reference Oil Price (AEO95) case was used for the baseline economics. This case projects a future world oil price with a predicted real oil price increase of about 2.4% per year.

(b) The hydrocarbon composition and heating value of the ANS gas provided as feedstock to LNG or GTL options is assumed to remain consistent over the project life at 1150 BTU/SCF.

(c) Final product sales price is a direct function of world oil prices, adjusted upwards for their special value and desirability as a fuel. The adjustment for LNG is a 10% Asian bonus and a $5/BBL premium for GTL liquids.

(d) Annual operating costs of each gas project are assumed to be 5% of total capital investments for the LNG project and $6/BBL for the GTL project.

(e) Operation efficiencies relative to the conversion of feedstock gas to salable product is assumed to be 91% for LNG and 60% for GTL.

(f) No additional investments are required to sell gas from PBU because of the extensive gas-handling facilities already in place at PBU for separation and reinjection of 7.5 BCFPD. The estimated capital investment required to develop PTU is $900 million (1995$).

(g) Excluding PTU development costs, the total investment requirements for the LNG project are adjusted upward from the $14 billion (1995$) publicly announced in 1994 by Yukon Pacific for its proposed 14 MMTPA LNG project, to $16 billion (1995$) for the 17 MMTPA LNG project required to accommodate concurrent gas sales from PBU and PTU at 2.49 BFCPD. For the GTL option to handle the same gas volume as the LNG option, the plant investment is $12 billion (1995$), based on $40,000 per daily barrel of liquid (DBL) of output capacity for a large scale (300 MBPD) state-of-the-art GTL operation in the Prudhoe Bay field area.

(h) Major gas sales from PBU, starting in 2005 and ramping up to 2.05 BCFPD in 5 years, will reduce PBU oil recovery by 400 million barrels oil (MMBO). PBU gas sales will end in 2036.

(i) Gas sales from PTU start in 2008 at 0.44 BCFPD, providing a peak rate of gas sales from PBU and PTU of 2.49 BCFPD. PTU gas sales end in 2027.

(j) Federal and State of Alaska taxes and other charges are assumed to remain as they are at this date.

Baseline Economic Results

The economic model results for the baseline assumptions show that the LNG option would yield an NPV_{10} of $11.5 billion (1995$), while the GTL option could be expected to yield a $10.7 billion (1995$) NPV_{10}, or about 7% less. These results compare to the $8.6 billion (1995$) for the no major gas sales case. The total incremental investments required for these yields, however, would be 24% greater for the LNG option than for the GTL option, $16.9 billion compared to $12.9 billion. These results are shown in Table 1. The discounted cash flow model takes into account all income and expenses and provides for a 10% rate of return on the incremental investment for preparing and transporting the gas to market for the respective gas sales options. These comparative calculations show that, in spite of potential reductions in PBU recovery of as much as 400 MMBO upon major gas sales, both LNG and GTL gas sales options have a greater payoff than the option of not selling the gas and continuing to reinject gas until the oil recovery reaches its economic limit. It is not nearly as clear which gas sales option is more preferable, however.

Table 1. Summary of gas sales options NPV's and investments.

	NPV_{10} LNG Option (1995$, billions)	NPV_{10} GTL Option (1995$, billions)
Prudhoe Bay Unit - No major gas sales	8.6	8.6
Prudhoe Bay Unit	11.1	10.4
Point Thomson Unit	0.4	0.3
Total NPV_{10}	11.5	10.7
Total Investment (1995$, billions)		
Gas option investment	16.0	12.0
Point Thomson development	0.9	0.9
Total	16.9	12.9

return for the gas projects and gas sales from PBU alone. For the LNG scenario, the breakeven flat oil price was $19.36/BBL; while the breakeven flat oil price for the GTL scenario was slightly higher at $19.94/BBL. Conversely, the sensitivity results showed that the delay of gas sales by as much as 5 yrs has only a slight effect on profitability of both the LNG and GTL options, assuming product sales are not deterred by such delay.

These sensitivity results, clearly show that changes in one or more of these assumptions could significantly alter the financial results:

- For example, in considering the LNG option, there are a large number of would be LNG suppliers in the world seeking to fill the expected LNG demand growth from gas-short Asian nations. Many of these suppliers are thought to have smaller capital outlays (not having the necessity of building an 800-mi gas pipeline as is required at the start for the Alaskan LNG project), and it is quite possible the LNG project Asian fuel bonus and its base LNG price will be less than anticipated, thereby reducing the LNG base economics. On the positive side, it is also possible, as more large LNG projects are designed and built around the world, that cost-saving measures will be found that would improve the LNG base economics.

- Likewise, for the GTL option, conversion efficiency might prove to be closer to the 57% level of the older South African plants rather than to the plant design level of 63% efficiency level for Shell's newer plant, thereby reducing the GTL base economics (a 60% conversion efficiency was used as the baseline assumption). In contrast, the target efficiency of 70 to 75% for advanced GTL technology under development may prove out in time to be ready for the rapid GTL deployment envisioned (or for major portions of the development, if such GTL development is phased in more slowly), which would improve the GTL base economics.

- Clearly, the economics of both of the gas sales options could be seriously impacted if investment cost contingencies associated with Alaska's climate, remoteness, and related factors prove to be underestimated; or if stand-alone projects such as the LNG and GTL projects require a greater than 10% rate of return to attract investors; or if world oil prices prove to be substantially lower than the DOE EIA reference oil price forecast (neither LNG nor GTL were found to be financially feasible at an $18/BBL flat oil price in this study's sensitivity analysis).

Conclusions

At this point in time, if the assumptions for the economic variables are valid, both the LNG and the GTL option can be considered as economically promising and warrant consideration in the decision-making process. (Although the variables are subject to normal levels of uncertainty, we believe they are valid based on the public information available to us.) However, it is not possible to conclude that one option is significantly better than the other.

This evaluation does, however, answer the specific question it was directed to address, namely: Is GTL conversion a feasible alternative for bringing ANS natural gas to market? The conclusion from this assessment is that state-of-the-art GTL conversion technology appears to be feasible and could be deployed within a meaningful time frame to sustain ANS and TAPS oil operations for 20 or more years beyond what might be anticipated without GTL.

Placing the issue of GTL feasibility aside, this ANS gas utilization assessment is not expected to be the last of what has been a number of studies focused on the marketing of Alaska's large, and potentially much larger, remote natural gas reserve. Alaskans face difficult gas development and marketing decisions in the near future, and need to develop the most complete understanding of the options possible. This is particularly so with respect to likely requests for State tax incentives and other actions that might be desired to move private commitments forward.

Recommendations

To assist in responding to such requests and other decisions that must be made to implement the sale of ANS gas, this report concludes with a number of recommended follow-up analyses that interested industry, State and federal parties may wish to pursue in a timely manner:

1. Existing Infrastructure Savings–The economics of both of the options could benefit through the utilization of portions of the infrastructure existing at Prudhoe Bay and along the TAPS pipeline. These possibilities should be examined on a site-specific basis, not only for a GTL plant that would be built on the North Slope, but also for the LNG gas pipeline and prospective Valdez liquefaction and shipping facilities. (YPC reports that basic engineering and design have been completed, but it is likely that further engineering and design involving the Prudhoe Bay operators and Alyeska Pipeline Service Company will lead to additional refinements.)

2. **Specific Cost Estimates**--More precise, process- and site-specific cost estimates of the LNG and GTL options should be developed because of the important sensitivity of the economics of both of these options to capital costs in particular. These estimates should incorporate the latest in technologies and designs, attempting also to provide sufficient detail on the cost impact of technology advances possible within a meaningful timeframe.

3. **TAPS Tariff Impact on Future Oil Production**--A more complete assessment is desirable concerning the effect of reduced TAPS tariffs, anticipated from the envisioned GTL product volumes, on future ANS oil production from all existing fields and potential developments. The several dollar per barrel reduction suggested by this study could be important in determining how long selected ANS reservoirs might continue to produce, and could affect whether non-producing reservoirs might be brought on line.

4. **Optimization of GTL Product Composition**--To better refine the operating cost and price estimates of proposed GTL operations, technical assessments should be directed to delineating potential liquid product compositions with respect to: (a) feasible process chemistry, (b) methods of TAPS shipment (mixed with the crude or stored and batched separately, similar to oil product pipelines), (c) crude and GTL product separation and the refining process(es) required to obtain the ultimate GTL product value, and (d) other factors as appropriate.

5. **ANS Cost Factors**--A clearer picture should be developed of the cost penalties associated with capital construction and facility operation in the arctic climate and remote location of the ANS. This should be done for both GTL and LNG options and should also examine general Lower 48 and Alaskan capital and operating cost differences to provide the most reliable cost estimates for gas sales decision making.

6. **Gas Sales Benefit to Alaska**--The potential economic benefits of each gas commercialization option on the various regions and overall State should be assessed in detail to aid in decision making. Such examination might include: (a) an analysis of the types and aggregate of manufacturing and labor components for construction and operation of each gas option and the resulting stimulation of State and local economic development, (b) direct and indirect local employment to be generated (and saved or extended,

if such be the case), and (c) gross and net revenues to State and local jurisdictions through prevailing or alternative tax schedules, etc.

7. **Alternative GTL Development Schedule**--The GTL option does not have to be developed at the pace required for the LNG project (resulting from the requirement to build the pipeline up front). The development scale was chosen to match the proposed TAGS LNG scale, pace, and scope in an attempt to make the obvious comparisons between the two options as comparable as possible. Hence, it would be useful to consider a slower development of GTL that could take advantage of the learning curve associated with deployment of new technology to lower costs and potentially take advantage of advanced GTL technology in the later modules for improved conversion efficiencies. Slower, incremental development would also reduce the magnitude of the capital outlays required in the early years and allow them to be offset by the increased profits from GTL sales. Such a development scenario increases the possibility of constructing more of the plant modules in Alaska and pacing the development over a long period of time to sustain higher employment and infrastructure levels within the State.

Idaho National Engineering and Environmental Laboratory

INEEL/EXT-99-01023

December 1999

OPTIONS FOR GAS-TO-LIQUIDS TECHNOLOGY IN ALASKA

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BECHTEL BWXT IDAHO, LLC

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Published December 1999

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Idaho Falls, Idaho 83415

Prepared for the
U.S. Department of Energy
Office of Fossil Energy
Under DOE Idaho Operations Office
Contract DE-AC07-99ID13727

ABSTRACT

The Alaska North Slope (ANS) holds a vast resource of natural gas but has no current method of transportation from the North Slope to world markets. The Prudhoe Bay field contains the largest portion of the discovered natural gas on the North Slope or about 21.8 Tcf of natural gas available for sale after CO_2 removal and satisfying power requirements and other North Slope use. The natural gas at Prudhoe Bay that is produced during oil production operations is reinjected and used to increase oil recovery. Currently, there are two broad gas-marketing schemes proposed for commercializing the natural gas on the North Slope. One is a gas-pipeline/liquefied natural gas (LNG) plant scenario; the other is a gas-to-liquids (GTL) option that chemically converts the natural gas to a stable, liquid syn-crude in a North Slope plant, eliminating the need for an additional pipeline from the North Slope to a southern Alaska port.

The purposes of this report were to assess the effect of applying new technology to the economics of a proposed GTL plant, to evaluate the potential of a slower-paced, staged deployment of GTL technology, and to evaluate the effect of GTL plant placement on economics.

Five scenarios were economically evaluated and compared: a no-major-gas-sales scenario, a gas-pipeline/LNG scenario, a fast-paced GTL development scenario, a slow-paced GTL development scenario, and a scenario which places the GTL plant in lower Alaska, instead of on the North Slope. Evaluations were completed using an after-tax discounted cash flow analysis. Results indicate that the slow-paced GTL scenario is the only one with a rate of return greater than 10 percent. The other scenarios did not show positive net present values under the economic conditions selected for the simulations. Their rank, in order of net present value, is as follows: slow-paced GTL development, no-major-gas-sales, fast-paced GTL development, a fast-paced GTL development in southern Alaska, and finally a gas-pipeline/LNG project.

The slow-paced GTL development would allow cost saving on subsequent expansions. These assumed savings along with the lowering of the transportation tariff combine to distinguish this option for marketing the North Slope gas from the other scenarios. Critical variables that need further consideration include the GTL plant cost, the GTL product premium, and operating and maintenance costs. Reducing these costs, or increasing the premium, would increase the profitability of the GTL process. In addition, understanding these variables better and reducing their uncertainty would allow a more accurate prediction of economic profitability.

EXECUTIVE SUMMARY

The Alaska North Slope (ANS) holds a vast resource of natural gas but has no current method of transportation from the North Slope to world markets. The Prudhoe Bay field contains the largest portion of the discovered natural gas on the North Slope or about 21.8 Tcf of natural gas available for sale after CO_2 removal and satisfying power requirements and other North Slope use. The natural gas at Prudhoe Bay that is produced during oil production operations is reinjected and used to increase oil recovery. Currently, there are two broad gas-marketing schemes proposed for commercializing the natural gas on the North Slope. One is a gas-pipeline/liquefied natural gas (LNG) plant scenario; the other is a gas-to-liquids (GTL) option that chemically converts the natural gas to a stable, liquid syn-crude in a North Slope plant, eliminating the need for an additional pipeline from the North Slope to a southern Alaska port.

The objective of this report is to incorporate new information regarding GTL technology into an economic evaluation of a GTL plant in Alaska, and to look at the development-pace and placement of a GTL project. In some ways, this current report follows up on an Idaho National Engineering & Environmental Laboratory report in 1996 by Thomas et al. for the Department of Energy entitled *Economics of Alaska North Slope Gas Utilization Options.* That 1996 DOE report analyzed a GTL scenario for marketing the ANS gas, a gas-pipeline/LNG scenario, and a no-gas-sales scenario. Since that report was published, new information regarding GTL technology was released to the public that appears to enhance the economic viability of the GTL project option for marketing ANS gas. This current report incorporates the new GTL-technology information and looks in more detail at the impact of the timing of GTL plant construction and location on the economic viability of a GTL project in Alaska.

Study Purposes

1) To apply technical advances to the GTL scenario evaluated in the 1996 DOE report to determine the effects new technology and knowledge have on the economics of the GTL project.

2) To evaluate the potential economic impact of a slower-paced, staged deployment of GTL technology on the North Slope; thus taking advantage of experience and technological improvements in later plant expansions.

3) To evaluate the concurrent development of both the LNG and GTL projects; with the GTL plant located in southern Alaska at the gas pipeline terminus.

To accomplish this, five scenarios were economically evaluated and compared: a no-major-gas-sales scenario, a gas-pipeline/LNG scenario, a fast-paced GTL development scenario, a staged, slow-paced GTL development scenario, and a scenario which places the GTL plant in southern Alaska, instead of on the North Slope.

Prudhoe Bay Field

The Prudhoe Bay field is the largest field in North America and lies on the Arctic coastline about 200 miles east of Point Barrow. There were about 23 billion barrels of oil originally in place (OOIP) and 46 Tcf of gas originally in place (OGIP). Ultimate oil-recovery estimates have been increasing over the years as more is learned about the field and enhanced oil recovery techniques and cost reduction efforts continue to improve.

Currently, Prudhoe Bay's natural gas is used to enhance oil recovery from the field. Major gas sales would take gas away from enhanced oil recovery projects and decrease ultimate oil recovery from the field. Some of the highly effective enhanced oil recovery programs that use the recycled gas are: pressure maintenance by gas re-injection, miscible injectant flooding, and water-alternating-gas programs. If major gas sales begin in 2005, a 400 million-barrel reduction in ultimate oil recovery is assumed. Major gas sales occurring later in the life of the Prudhoe Bay field would have a less significant impact on oil recovery simply because there would be less oil available to recover. Major gas sales beginning in 2010 are assumed to reduce ultimate recovery by 100 million barrels; and gas sales beginning in 2015 would have a negligible effect on oil recovery.

Of the 46 Tcf of natural gas originally in place in the Prudhoe Bay field, 30 Tcf resides in the gas cap and 16 Tcf lies within the oil rim. Natural gas (containing 12% CO_2) is currently being produced at a rate of about 8 Bcf/D from PBU as part of oil production operations. The heavier components of the produced gas are removed and shipped to market as natural gas liquids (NGL) or used as miscible injectant to recover crude oil. Some of the lean gas is used as fuel and the remainder (about 7 Bcf/D) is reinjected into the gas cap. Of the original 46 Tcf in place, over 2.8 Tcf have been used as fuel for heating or sold as NGL to date.

Current Status of Gas Commercialization Efforts

Commercializing or marketing the natural gas residing on the North Slope has been a major goal of the field operators since the Prudhoe Bay field was first unitized. Recently, efforts to arrive at an economic marketing plan have intensified. The two schemes receiving the most consideration are an LNG option and a GTL option. The LNG scheme involves constructing an 800-mile gas pipeline, an LNG facility in Valdez, AK, and shipping LNG to Asia via LNG tankers. The GTL scheme involves constructing a GTL plant on the North Slope and transporting the GTL product through TAPS and to market via regular oil tankers. However, neither scenario has been selected exclusively as the preferred method to market the large gas resource on the North Slope.

In January 1998, the Alaska Department of Natural Resources released a report entitled *Alaska North Slope Gas Commercialization Team – Report to the Governor*. This report discussed ways the State of Alaska and the federal government could improve the economic feasibility and competitiveness of a North Slope gas project and focused almost exclusively on the LNG option. It addressed ways the state could lower taxes or change the tax structure to increase the economic viability of a North Slope gas project.

In letters attached to the *Report to the Governor*, ARCO, BP, and Exxon commented on the contents of the report and general gas-commercialization efforts. ARCO expressed concern that despite the State's efforts, an LNG project may still be undercut by higher rate-of-return projects from around the world to provide anticipated Far East markets. BP encouraged the state to address the fiscal and regulatory system with respect to the emerging GTL technology as well. Exxon urged the State to maintain adequate flexibility to address the special needs of any stranded gas project, whether it be LNG or GTL.

Review of LNG with Respect to Alaska

In 1997, total world LNG imports were 81.759 million tons, of which, 61.728 million tons went to East Asia, or 75% of world LNG imports. Japan imported 47.106 million tons, Korea imported 11.457 million tons, and Taiwan imported 3.165 million tons in 1997. Japan imports LNG from the U.S.A. (Alaska), Brunei, Abu Dhabi, Indonesia, Malaysia, Australia, and Qatar.

LNG demand in East Asia is expected to rise to 80 million tons in 2000, 100 million tons in 2005, and 130 million tons in 2010. There are many new potential LNG supply sources competing to fill this growing market. These include Qatar, Oman, and Yemen in the Middle East; Malaysia and Indonesia in Asia; the north and northwest areas of Australia; and Sakhalin and Alaska in the north Pacific. Whether an ANS gas project can compete with these or other new sources of LNG remains to be seen.

To help the commercialize the ANS gas, the state of Alaska passed the Alaska Stranded Gas Development Act in 1998 that authorized the state to negotiate payments from sponsors of the proposed gas pipeline in lieu of taxes that otherwise would be imposed. Changes in the federal tax structure and reductions in capital costs are more important to the economics of a project than changes in state tax structure. Nevertheless, the state tax restructuring enabled by the State's Stranded Gas Act would help the economics of the project, especially if combined with federal tax changes and reductions in capital costs.

Review of GTL Technologies

The GTL process evaluated in the 1996 DOE report was taken from information regarding the Shell middle-distillate synthesis technology. Since that time, several competing technologies have been publicly discussed that could significantly improve the economics of GTL technology.

Most of the new GTL information has come from Exxon and Syntroleum, two companies with competing GTL processes. Both processes are based on the Fischer-Tropsch (FT) technology, but each uses a different method to produce the syn-gas used as a feed into the FT process and different catalysts in the FT reactor. Syntroleum has perhaps been an open promoter of GTL technology and has presented much of their progress and technology details. ARCO, a major ANS gas owner, has a license agreement with Syntroleum and began operations of a 70-bbl/D pilot plant of the GTL technology in Washington State in 1999. Exxon operated a pilot-scale GTL plant in Baton Rouge, LA from 1990 to 1993 and is studying application of GTL on the North Slope and elsewhere with data from that plant.

Capital Costs

A feasibility study of applying Exxon's Advanced Gas Conversion for the 21st Century (AGC-21) technology to produce 50,000 B/D of middle distillates and other oil based products from 500 million cubic feet of gas was completed jointly by Exxon and Qatar General Petroleum Corp. Capital costs for the project were estimated to be $1.2 billion – or $24,000 per daily barrel (DBL) of capacity. Other recent reports estimate capital costs for a generic GTL plant to range from $35,000 per daily barrel (DBL) down to $12,000/DBL. Based on these reports, capital costs for a generic GTL plant located on the Gulf Coast are assigned a value of $24,000/DBL for this report, equal to the capital costs calculated in the Exxon/Qatar feasibility study.

When considering an installation on the North Slope, a capital cost factor between 1.3 and 2.0 is applied to account for factors intrinsic to the ANS for installations originally cost-estimated for the U.S. Gulf Coast area. A North Slope capital cost factor of 1.5 is used to calculate capital costs in this report.

Applying the 1.5 North Slope capital cost factor to the base value of $24,000/DBL for the generic GTL plant yields capital costs for a North Slope location of $36,000/DBL.

Costs for first-of-a-kind plants do not often represent the costs of a mature technology. As more plants are built, costs for succeeding plants have historically been reduced. This is called taking advantage of the "learning curve". The cost improvement slope for a large GTL plant is estimated to be -0.74, which means that for each doubling of cumulative industry production, costs decline to about 74 percent of what they were prior to that doubling. If the GTL plant were constructed in stages, costs of succeeding deployments of the technology would presumably be less than previous versions.

Economic Evaluations

Evaluating both the Prudhoe Bay field model and the gas project model is necessary to effectively evaluate the scenarios being considered and are tied together by the natural gas transfer price. The transfer price is calculated with the use of the "net back" term. The "net back" refers to the 'net' fraction of the gas price sold by the gas project (GTL plant or LNG project) that is returned 'back' to the Prudhoe Bay unit operators as payment for the gas.

Scenarios Evaluated

Three GTL scenarios, one LNG scenario, and one no-gas-sales scenario were evaluated:

- The No Major Gas Sales scenario consists of continuing with current operations utilizing the natural gas to maximize oil production. Under this scenario, oil production continues until 2025, when the economic limit of the Prudhoe Bay field is reached.

- The Natural Gas Pipeline/LNG Project scenario takes natural gas from Prudhoe Bay beginning in 2005 and reaches a maximum rate of 2.0 Bcf/D in 2009. Gas, at a rate of 0.5 Bcf/D, from the Point Thomson unit, which lies 50 miles east of Prudhoe Bay, is also fed into this scenario.

- A Fast-Paced GTL Development scenario consists of constructing a 300,000-B/D GTL plant (2.5 Bcf/D feed rate) on the North Slope to match the timing and volumes proposed in the LNG scenario.

- A Slower-Paced GTL Development scenario consists of a GTL plant construction schedule designed to take advantage of the learning curve associated with implementation of newer technologies. Located on the North Slope, the plant takes gas from Prudhoe Bay at a rate of 0.5 Bcf/D beginning in 2005. In 2010, a new GTL module of the same capacity is in place; with a new 0.5 Bcf/D module being constructed every 5 years until a total capacity of 2.5 Bcf/D (300,000 bbl/D) is reached.

- A 300,000-B/D GTL plant (fast-paced) is located in Valdez, AK. This scenario assumes that the natural gas pipeline is built and a tariff is charged to the gas passing through the line. The assumed gas purchase rate is equal to the LNG scenario. A lower capital-cost factor of 1.2 is applied at the Valdez location as opposed to the 1.5 capital cost factor associated with a North Slope location.

TAPS Tariff Discussion

The tariff that is charged for transporting liquid through the Trans-Alaska Pipeline System (TAPS) is an important economic parameter. The tariff calculation is based on costs to operate the pipeline, future investments, pipeline profit, and liquid flowrate through the pipeline. TAPS tariffs are a very important part of an analysis of projects that produce liquids from the North Slope of Alaska. The same tariff is applied to all liquids passing through the pipeline, whether it be crude oil, natural gas liquids, or product from a GTL plant. A higher transportation tariff reduces the value of the wellhead product.

GTL liquids increase the flow rate through TAPS, thus lowering the tariff. The LNG option reduces the flow rate through TAPS by decreasing the oil recovery, which increases the TAPS tariff. TAPS tariffs can positively or negatively impact the economic potential of all oil-producing fields on the North Slope, not only the Prudhoe Bay and the Point Thomson units. The benefit of lowering TAPS tariffs because of the addition of GTL products to these other fields is not quantified in this report, but is expected to be significant as a whole.

Economic Results

A deterministic evaluation of the economic viability of the scenarios outlined above was accomplished by discounted cash flow analysis. (Refer to section 6.2 of the full report for an explanation and discussion of discounted cash flow analysis.) Results of the economic evaluations are best represented by the net present value of the project. The term NPV_{10} represents the net present value evaluated at a discount rate of 10%. Summary Table 1 lists the results of the evaluation for four of the scenarios.

Summary Table 1. Economic evaluations of major gas sales scenarios for the North Slope of Alaska.

Scenario	Entity	NPV_{10} ($, millions)
Major gas sales to gas-pipeline/LNG-plant	Incremental Prudhoe Bay unit	589
	Gas-pipeline/LNG-plant	-2,991
	Total	-2,402
Major gas sales to GTL plant on North Slope (fast-paced)	Incremental Prudhoe Bay unit	914
	GTL plant	-1,297
	Total	-383
Major gas sales to a GTL plant in southern Alaska (fast-paced)	Incremental Prudhoe Bay unit	542
	GTL plant	-1,908
	Total	-1,366
Major gas sales to GTL plant on North Slope (slow-paced)	Incremental Prudhoe Bay unit	-113
	GTL plant	945
	Total	832

Of the scenarios analyzed in Summary Table 1, only the slow-paced GTL development scenario has a positive, incremental combined net present value using a discount rate of 10%. However, a negative NPV_{10} means that its rate of return is less than the discount rate of 10% and does not necessarily mean that a project loses money.

The gas sales revenues of slow-paced North Slope GTL plant are realized later in the life of this scenario than in the fast-paced GTL scenarios and the LNG scenario, which tends to decrease the net present value of the project. However, the savings in capital costs associated with the "learning curve" that are incorporated into this option outweigh the added discount in revenue caused by delaying the gas sales.

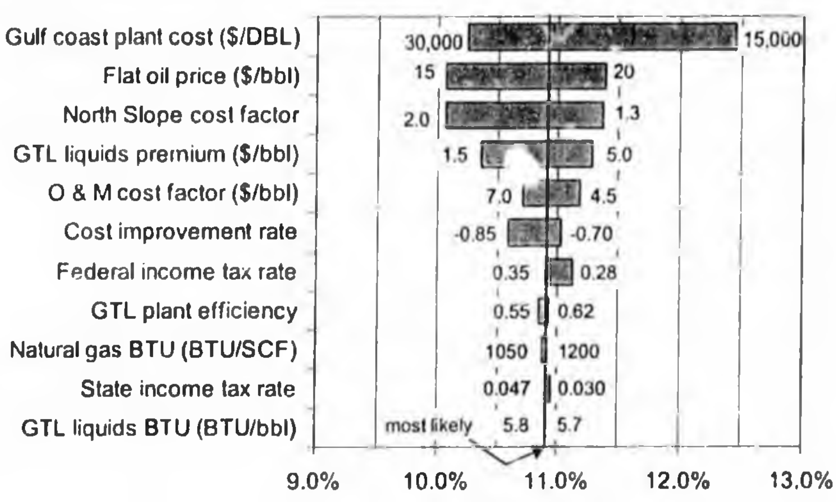
A fast-paced GTL plant in southern Alaska (Valdez) was compared to the fast-paced GTL plant on the North Slope. Locating the plant at an ice-free port could potentially be economically attractive compared to a North Slope location. Capital costs would be less than the North Slope because of reduced shipping, labor, and materials costs. In the economic evaluation, the capital cost factor was lowered from 1.5 (for the North Slope location) to 2. The other major change in evaluations is the additional price of the natural gas at Valdez. The $6 billion gas pipeline transporting natural gas from the North Slope to Valdez would still be constructed; adding about $0.80/Mcf to the gas feed cost.

Sensitivity Analysis

There are many sensitivity analyses that could be run on these evaluations. Learning the ramifications of varying input parameters is important to understanding project economics. As this report was primarily concerned with economics of gas-to-liquids technology Alaska, sensitivities were performed only on the GTL plant portion of the total scenarios. The field portion of the scenarios was not further included in the sensitivity analyses.

The object of the analyses was to determine which input parameters cause the greatest effect on project economics. This information is vital in determining those parameters that offer the greatest potential for increasing or decreasing economic viability. These parameters require the most attention and are natural targets for further study by increasing research efforts.

Summary Figure 1 shows results from a sensitivity analysis of the input data for the slow-paced GTL plant development. The numbers on each end of the respective horizontal bars indicate the possible range of the variable in question; while the length of the bar represents that variable's effect economic output. The vertical "most likely" line on the figure indicates the default value for each variable.



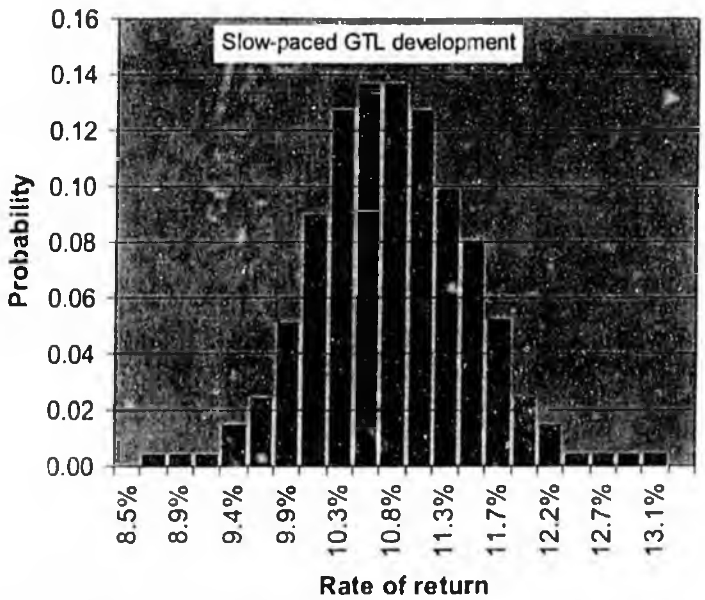
Summary Figure 1 - Sensitivity of input parameters with respect to project economics for the slow-paced GTL plant deployment.

The four most critical variables, as seen in Summary Figure 1, are the Gulf Coast GTL plant cost, the world oil price, the North Slope cost factor, and the GTL liquids per barrel premium. The ROR using the most likely values for each of the variables is 10.9 percent as shown in Summary Figure 1.

Monte Carlo analysis

The Monte Carlo simulation technique permits a "probabilistic analysis" of project economics by applying probability distributions to the input parameters as opposed to the deterministic results tabulated in Summary Table 1. Probabilistic sensitivity analyses do not compute a single result; instead, the outcome is a range of possible results.

Summary Figure 2 is a plot of the probability-of-occurrence versus rate-of-return for a slow-paced GTL plant development on the North Slope. Possible rates of return for a slow-paced GTL development on the North Slope can range from 8.7 percent to 13.1 percent. Applying a 90 percent confidence interval sets the rate or return between 9.8 percent and 11.9 percent. The median value of 10.8 percent indicates that half of the time, a rate of return calculation would return a value of 10.8 percent or greater. The standard deviation is 0.7 percent, which demonstrates that the results are tightly centered on the average of 10.8 percent.



Summary Figure 2 – Frequency of the rate of return for a slow-paced GTL plant development after 10000 iterations.

Conclusions

The purposes of this report were to identify and explore the effect of applying new technology to the economics of a proposed GTL plant, to evaluate the potential of a slower-paced deployment of GTL technology, and to evaluate the effect of GTL plant placement on economics.

Of the gas marketing scenarios evaluated, results indicate that the slow-paced GTL scenario is the only one with a rate of return greater than 10 percent. The other scenarios did not show positive net present values under the economic conditions selected for the simulations. Their rank, in order of net present value, is as follows: slow-paced GTL development, no-major-gas-sales, fast-paced GTL development, fast-paced GTL development in southern Alaska, and finally a gas-pipeline/LNG project.

The slow-paced GTL development would allow cost savings on subsequent expansions. These assumed savings along with the lowering of the transportation tariff combine to distinguish this option for marketing the North Slope gas from the other scenarios. Critical variables that need further consideration include the GTL plant cost, the GTL product premium, and operating and maintenance costs. Reducing these costs or increasing the premium could dramatically increase the profitability of the GTL process. Understanding these variables better and reducing their uncertainty would allow a more accurate prediction of economic profitability. Further study of these variables (GTL plant cost, GTL product premium, and O & M costs) is recommended. In addition, a study to quantify the benefit of a tariff reduction caused by a North Slope GTL plant to the economics of other fields (besides Prudhoe Bay) is also recommended.

ACKNOWLEDGMENTS

This work was funded by the U.S. Department of Energy's National Energy Technology Laboratory (U.S. DOE-NETL) from the Natural Gas Processing and Utilization division of Emerging Processing Technology Applications managed by Venkat Venkataraman.

The author acknowledges the significant role played by Ralph Avellanet of the U.S. DOE – Fossil Energy and Daniel Driscoll of the U.S. DOE-NETL in providing programmatic guidance and review of this report. Richard Rice of the Idaho National Engineering & Environmental Laboratory (INEEL) and manager of Fossil Energy Technologies, provided overall guidance on the scope of the report. Charles Thomas, also of the INEEL and program manager, provided critical review of the report and made contributions to the contents.

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Options for Gas-to-Liquids Technology in Alaska

1. INTRODUCTION

The Alaska North Slope (ANS) holds a vast resource of natural gas that could be of great benefit not only to Alaska, but to the whole United States and other countries provided an economical scheme could be developed to transport the gas from the North Slope. Currently, the produced gas is being reinjected to effectively increase oil recovery, but will have greater economic benefit if able to be transported from the North Slope to world markets as oil production wanes in the future. The Prudhoe Bay field contains the largest portion of the discovered natural gas on the North Slope or about 21.8 Tcf of natural gas available for sale after CO_2 removal and satisfying power requirements and other North Slope use.

This report focuses on the economics of applying technology that converts natural gas to high-quality liquid transportation fuels as a method to market the North Slope gas. In 1996, the Idaho National Engineering & Environmental Laboratory (INEEL) published a report for the U.S. Department of Energy entitled "*Economics of Alaska North Slope Gas Utilization Options,*" by Thomas, et al.[1] In that report, which will be referred to as the 1996 DOE report, three gas marketing scenarios were compared. **Scenario 1** was to continue oil production operations with no major natural gas sales. **Scenario 2** was to construct an 800-mile natural gas pipeline paralleling the trans-Alaska oil pipeline system (TAPS) and convert the natural gas to liquefied natural gas (LNG) at or near Valdez, AK; marketing the LNG in the Asian Pacific Rim via LNG tankers. **Scenario 3** was to build a gas-to-liquids (GTL) plant on the North Slope that would convert an equivalent quantity of natural gas into a stable, liquid fuel that would then be transported through TAPS – marketing the GTL product on the U.S. West Coast as transportation fuel.

Since 1996, new information regarding GTL technology has been released to the public that appears to enhance the economic viability of the GTL project option for marketing ANS gas and was not incorporated in the 1996 DOE study. The objective of this current report is to expand the work completed in the 1996 DOE report and to conduct a focussed, follow-up investigation to that work. Specifically, to incorporate new information regarding GTL technology, and to look at the development-pace and placement of a GTL project. It has been argued that by constructing a large GTL facility in stages, one could take advantage of the learning curve associated with new technologies and reduce costs of subsequent stages. These cost savings could offset revenue losses associated with the time-value of money.

This report relies on portions of the work performed in the 1996 DOE report. For example, the Prudhoe Bay field analysis, the TAPS tariff calculation methodology, and the framework for the economic analysis were updated from the 1996 DOE report.

In performing an economic analysis of a gas-marketing scenario involving natural gas from the ANS, it is necessary to understand the interrelationship between gas sales and oil revenue. For example, the quantity, timing, and pace of major gas sales can have a major impact on the oil recovery of the Prudhoe Bay field. The Prudhoe Bay natural gas is currently being used to enhance oil recovery from the field. If that gas is sold, it becomes unavailable for use in enhanced oil recovery operations, and although selling the gas may generate revenue, its use may reduce the revenue generated from oil operations. The economic evaluation of a gas-marketing scenario, therefore, must include an analysis of the entire producing field – both oil and gas revenues – as well as an analysis of the operations of the gas-marketing scheme.

1.1 Purpose

The purposes of this study are:

1) To apply technical advances to the GTL scenario evaluated in the 1996 DOE report to determine the effects new technology and knowledge have on the economics of the GTL project.

2) To evaluate the potential economic impact of a slower-paced, staged deployment of GTL technology on the North Slope; thus taking advantage of experience and technological improvements in later plant expansions.

3) To evaluate the concurrent development of both the LNG and GTL projects; with the GTL plant located in southern Alaska at the gas pipeline terminus.

2. OVERVIEW OF NORTH SLOPE FIELDS AND PRODUCTION

Oil production is projected to increase from the North Slope within the next five years, reversing a seven-year stretch of continual yearly declines. The increase is expected to be fueled by production from six new fields – Alpine, Badami, Northstar, Liberty, Tarn, and PBU satellites; and by increased production from Schrader Bluff and West Sak. However, development has been slowed because of depressed oil prices in 1998 and early 1999.

2.1 ANWR Update[2]

The U.S. Geological Survey's (USGS) mid-range estimate for oil-in-place under the 1002 area in the Arctic National Wildlife Refuge was increased in May 1998 to 20.7 billion barrels, up from 13.8 billion barrels estimated in 1987. The mid-range estimate of recoverable oil from this area was raised to 10.3 billion barrels.

Several developments have influenced the understanding of oil potential in the area. Exploratory wells, such as those recently drilled in the Sourdough area,[3] have provided new geologic data for the USGS assessment. Seismic information from older wells drilled in the area was given to the USGS. Advances in processing older 2-D seismic data have been developed and were used by the assessment team. Finally, cost-cutting and technological advances have reduced the minimum field size for stand-alone economic development from 400 to 500 million barrels down to 100 million barrels.

2.2 Future Leasing Rounds

The U.S. Department of Interior (DOI) announced in 1998 that 4 million acres in the northeast corner of the National Petroleum Reserve in Alaska – just to the west of the Alpine field, ARCO's discovery on the Colville River delta – would be available for leasing. The Interior Department estimates the reserve's northeast quadrant holds from 500 million barrels to 2.2 billion barrels of recoverable crude oil.[4]

2.3 Prudhoe Bay Field

The Prudhoe Bay field is the largest field in North America and lies on the Arctic coastline about 200 miles east of Point Barrow. There were about 23 billion barrels of oil originally in place (OOIP) and 46 Tcf of gas originally in place. Ultimate oil-recovery estimates have been increasing over the years as more is learned about the field and as enhanced oil recovery techniques and cost reduction efforts continue to improve.

2.3.1 Development Plans

As of early 1998, development plans indicated that 105 penetrations were planned for the Prudhoe Bay field in 1998 – 51 coiled tubing sidetracks, 33 will be conventional sidetracks, and 21 new wells.[5] In 1999 and 2000, 115 penetrations are planned per year – 61 coiled tubing sidetracks, 32 conventional sidetracks, and 22 new wells. Development plans for years 2001 to 2005 were extrapolated from historical data to 50 penetrations per year and the same ratio of penetration types was assumed.[6] No new well penetrations were assumed beyond the year 2005 as shown in Fig. 1.

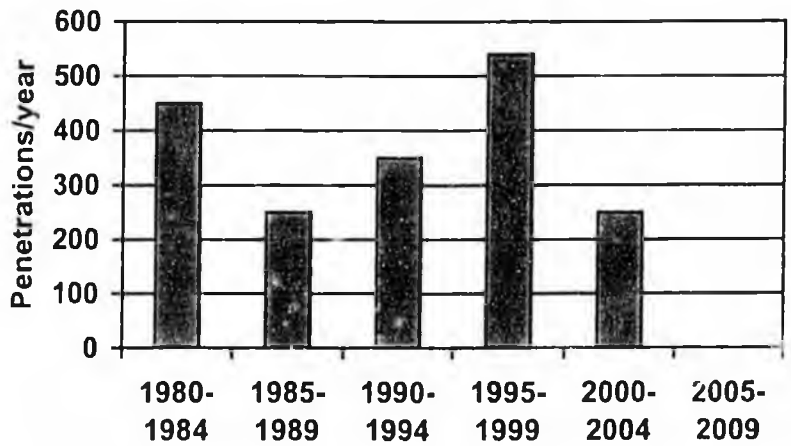

Figure 1 - Well penetrations in the Prudhoe Bay field.

2.3.2 Production Forecasts and Recoverable Oil

Production curves in this report are forecasted through 2025 for the entire North Slope as well as for the Prudhoe Bay unit. Forecasts were taken from data supplied by the Alaska Division of Natural Resources – Division of Oil and Gas (ADNR–DOG), which forecasts only through the year 2020.[7] Oil production for the Prudhoe Bay field in 2020 is projected to be equal to 223 Mbbl/D, which is greater than the assumed minimum rate of 160 Mbbl/D necessary for economic viability of the field.[a] This indicates that more oil will be produced from Prudhoe Bay beyond 2020. An exponential decline rate of 0.054 yr^{-1} was calculated from data between 2005 and 2020 and was applied to a five-year extrapolation of the ADNR–DOG forecast, which extended the forecast to 2025 as shown in Fig 2. Extending Prudhoe Bay production until 2025 brings the production rate down to 169 Mbbl/D, which is in line with industry's assumed minimum rate for the field.

Ultimate recovery from the Prudhoe Bay unit (PBU) was estimated to be 13.0 billion barrels in the 1996 DOE report. However, Platt's Oilgram has reported that ultimate recovery could be higher than 13 billion barrels.[8] In addition, according to the 1998 ADNR–DOG oil production forecast, the ultimate recovery from PBU is expected to be 13.32 billion barrels. By extrapolating the forecast data another five years the expected ultimate recovery from PBU used in this study was increased to 13.67 billion barrels.

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[a] Personal communication with industry representatives, March 1998.

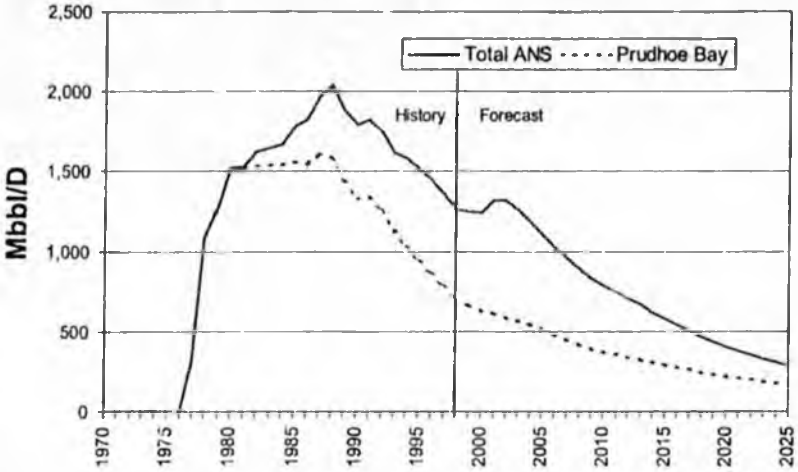

Figure 2 - Oil production forecast for the Prudhoe Bay unit and the entire North Slope.

2.3.3 Prudhoe Bay Investments

Estimates of future investments were based on drilling plans; current drilling costs; and planned surface facilities costs (see section 2.3.1). The cost of the average well penetration has been reduced from the $2.2 million used in the 1996 DOE report to $1.5 million.[9] Investment for expansion of the ongoing miscible injectant project is expected to total $165 million and is scheduled to be completed by 2000.

2.3.4 Operating Costs

Operating costs are estimated based on a cost per barrel of total fluid (BTF) produced. The forecast for future total fluid produced was obtained by plotting the water cut – obtained from historical Prudhoe Bay production data – versus percent recovery and extrapolating to 75% water cut at 100% of ultimate recovery, as shown in Fig. 3. The water cut is defined as the fraction of the total produced fluid that is water. The operating cost factor of $1.180/BTF used in this study was inflated to 1998$ from the oper-

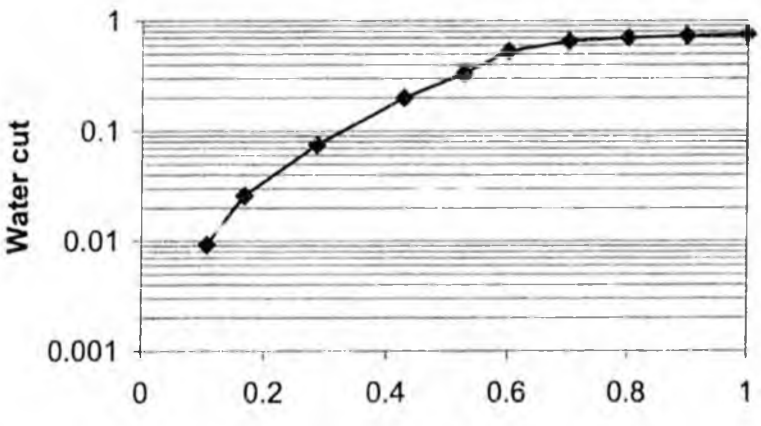

Figure 3 – Water-cut curve used to calculate operating costs for the Prudhoe Bay unit.

ating-cost factor used in the 1996 DOE report.

2.3.5 Transportation Costs

Transportation costs are the sum of costs associated with transporting the oil through TAPS and those associated with shipping the oil from Valdez to world markets. Both costs are calculated as tariffs: a TAPS tariff and a marine tariff.

2.3.5.1 TAPS Tariff. The TAPS tariff used in this report uses the same methodology as in the 1996 DOE report; however, the values of input variables have been updated to reflect 1998 values and forecasts of expenditures. Yearly tariffs used in the economic evaluations are based on total liquid throughput, pipeline operating expenses, and allowable margin. The calculated TAPS tariff for scenario 1 (no future major gas sales) is shown in Fig. 4. TAPS tariff forecasts for other scenarios and their importance in economic evaluations are discussed in section 6.3.2.

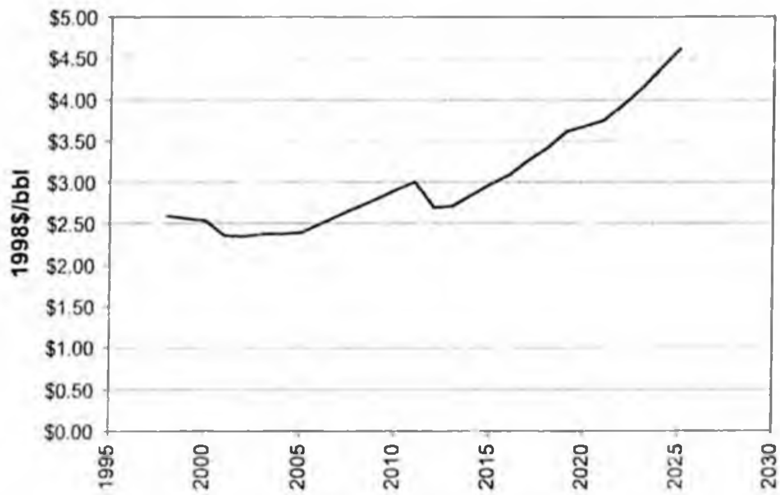

Figure 4 - TAPS tariff forecast for scenario with no major gas sales.

2.3.5.2 Marine Tariff. The marine tariff values used in transportation calculations are taken from the Alaska Department of Revenue, Fall 1997 Revenue Sources Book, Table 8, and average about $1.80/bbl (1998$) in the future. Forecasted values are shown in Fig. 5.

2.3.6 Lost Oil Recovery due to Major Gas Sales

Oil recovery can be affected by marketing the produced natural gas off the North Slope as opposed to using it to enhance oil production according to the 1996 DOE report. If major gas sales begin in 2005, 400 million bbl of oil is assumed lost. This would occur because of the unavailability of the gas for use in highly effective enhanced oil recovery programs such as pressure maintenance, miscible injectant flooding, and water-alternating-gas programs. Later major gas sales would have a lesser impact on oil recovery simply because there would be less oil available to recover. Major gas sales beginning in 2010 are assumed to cause a loss of 100 million bbl; and gas sales beginning in 2015 would have a negligible effect on oil recovery.

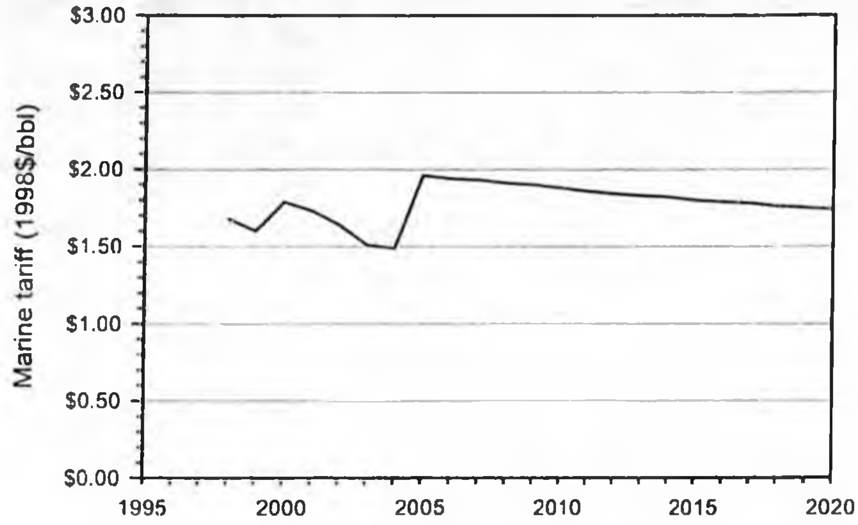

Figure 5 - Marine tariff forecast.

2.3.7 Gas Production from Prudhoe Bay

Of the 46 Tcf of natural gas originally in place in the Prudhoe Bay field, 30 Tcf resides in the gas cap and 16 Tcf lies within the oil rim.[1] Natural gas (containing 12% CO_2) is currently being produced at a rate of about 8 Bcf/D from PBU as part of oil production operations. The heavier components of the produced gas are removed and shipped to market as natural gas liquids (NGL) or used as miscible injectant to recover crude oil. Some of the lean gas is used as fuel and the remainder (about 7 Bcf/D) is reinjected into the gas cap. Of the original 46 Tcf in place, over 2.8 Tcf have been used as fuel for heating or sold as NGL to date.

A recovery factor of 80 percent is assumed to apply to the gas in the gas cap and a recovery factor of 60 percent to the gas in the oil rim. Recoverable gas in the gas cap is then 24 Tcf and oil rim gas is 9.6 Tcf for a total of 33.6 Tcf of recoverable gas. A total of 8.8 Tcf are expected to be unavailable for sale due to total lease use, local sales, NGL sales, and shrinkage, which leaves net gas (including CO_2) of 24.8 Tcf. Removing the CO_2 lowers the net gas available for sale from PBU to 21.8 Tcf.

3. CURRENT STATUS OF GAS COMMERCIALIZATION EFFORTS

Commercializing or marketing the natural gas residing on the North Slope has been a major goal of the field operators since the Prudhoe Bay field was first unitized. Recently, efforts to arrive at an economic marketing plan have intensified. Two scenarios receiving the most consideration are an LNG option and a GTL option. The LNG scenario involves constructing an 800-mile gas pipeline, an LNG facility in Valdez, AK, and shipping LNG to Asia via LNG tankers. The GTL scenario involves constructing a GTL plant on the North Slope and transporting the GTL product through TAPS and to market via regular oil tankers. However, neither scenario has been selected exclusively as the preferred method to market the large gas resource on the North Slope.

In January 1998, the Alaska Department of Natural Resources released a report entitled *Alaska North Slope Gas Commercialization Team – Report to the Governor.*[10] This report discussed ways the State of Alaska and the federal government could improve the economic feasibility and competitiveness of a North Slope gas project and focused almost exclusively on the LNG option. It addressed ways the state could lower taxes or change the tax structure to increase the economic viability of a North Slope gas project.

In letters attached to the *Report to the Governor*, ARCO, BP, and Exxon commented on the contents of the report and general gas-commercialization efforts. ARCO expressed concern that despite the State's efforts, an LNG project may still be undercut by higher rate-of-return projects from around the world to provide anticipated Far East markets. BP encouraged the state to address the fiscal and regulatory system with respect to the emerging GTL technology as well. Exxon urged the State to maintain adequate flexibility to address the special needs of any stranded gas project, whether it be LNG or GTL.

ARCO has constructed a GTL pilot plant at Cherry Point, its refinery in Washington State, where it is conducting research on catalysts and reactor design technology and employs a GTL approach that uses air instead of oxygen to generate syn-gas. Catalyst selection and process reactor design changes are being studied to help reduce the costs of GTL technology.[11]

In July 1998, Exxon Corporation formed a study group to look at the potential for a gas-to-liquids plant on Alaska's North Slope. Although Exxon considers liquefied natural gas as the first option for Alaska's Arctic gas reserves, the company believes there is enough gas on the North Slope for both an LNG and a GTL project.[12]

Yukon Pacific Corporation (CSX Corporation) reported in August 1998 that the cost to construct the 800-mile gas pipeline could be reduced by $1 to $2 billion if the latest pipeline engineering technology was incorporated in the line's construction cost estimates.[13]

Also in August 1998, it was announced that a group of five companies signed the Alaska North Slope (ANS) Gas Project Sponsor Agreement.[14] The agreement is meant to identify a viable project for transporting a portion of the vast ANS stranded gas reserves to markets in East Asia in the form of liquefied natural gas. The initial phase of the agreement will cover a four-year period costing approximately $100 million, will focus primarily on defining costs and minimizing economic uncertainty, and will address possible pipeline routes, engineering, permitting, and commercial work of all aspects of the project. Companies involved in the agreement included ARCO Alaska, Inc. 37%, Foothills Pipe Lines Ltd. 22%, Marubeni Corporation 17%, Phillips Petroleum Company 12%, and CSX Corporation 12%. However, in August 1999, CSX withdrew from the group, opting to focus solely on a preferred gas pipeline to Valdez route.

4. BRIEF REVIEW OF LNG STATUS

In 1997, total world LNG imports were 81.759 million tons, of which, 61.728 million tons went to East Asia, or 75% of world LNG imports. Japan imported 47.106 million tons, Korea imported 11.457 million tons, and Taiwan imported 3.165 million tons in 1997.[15] Japan imports LNG from the U.S.A. (Alaska), Brunei, Abu Dhabi, Indonesia, Malaysia, Australia, and Qatar.[16]

LNG demand in East Asia is expected to rise to 80 million tons in 2000, 100 million tons in 2005, and 130 million tons in 2010.[16] There are many new potential LNG supply sources competing to fill this growing market. These include Qatar, Oman, and Yemen in the Middle East; Malaysia and Indonesia in Asia; the north and northwest areas of Australia; and Sakhalin and Alaska in the north Pacific.[16] Indonesia's Tangguh Project boosted proved reserves, critical to the formation of an LNG project, dramatically from 6.3 Tcf reported in 1997 to 14.4 Tcf as of July 31, 1998.[17] Whether an ANS gas project can compete with these or other new sources of LNG remains to be seen.

The state of Alaska passed the Alaska Stranded Gas Development Act in early 1998 that authorized the state to negotiate payments from sponsors of the proposed gas line in lieu of taxes that otherwise would be imposed. These taxes include state and local property taxes, sales and use taxes, production or severance tax, and state corporate income tax. In addition, it provides municipalities the option of an equity interest in the project in lieu of taxes. The Act was written exclusively for the gas pipeline/LNG option, excluding the potential gas-to-liquids scenario for marketing ANS gas.[18]

According to a report by Pedro van Meurs, changes in the federal tax structure and reductions in capital costs are more important to the economics of a project than changes in state tax structure.[19] Nevertheless, the state tax restructuring accomplished by the State's Stranded Gas Act would help the economics of the project, especially if combined with federal tax changes and reductions in capital costs.[20]

5. STATUS OF GTL TECHNOLOGIES

The GTL process evaluated in the 1996 DOE report was based on the Shell middle-distillate synthesis technology as discussed in the J. Eilers et al. paper: "The Shell Middle Distillate Synthesis Process (SMDS)."[21] This paper was written before Shell's Bintulu, Malaysia plant began operation in 1992. Since that time, several competing technologies have been brought to light that could significantly improve the economics of GTL technology.

5.1 Advances in GTL Technology

The Alaska Department of Revenue compiled a brief comparison of six gas-to-liquid technologies:

1) A basic Fischer-Tropsch (F-T) technology,
2) Sasol's F-T technology,
3) Exxon's AGC-21,
4) BP's compact steam reformer,
5) Syntroleum's diluted nitrogen technology, and
6) An F-T process using DOE's Ceramic Membrane.

This comparison (shown in the Appendix) gives capital costs per barrel of liquid product and O&M costs per barrel of liquid product. The values given have been generated from publicly available data, but not necessarily from existing plants. The Appendix compares not only costs, but explains each process and notes differences in technology and approach.

Syntroleum has been a vigorous promoter of GTL technology and has presented some details of their progress and technology. It has taken the approach of using air instead of pure oxygen in the syngas generation step of the GTL process. In February 1998, SLH Corp, Syntroleum's parent corporation announced plans to build an 8,000 B/D gas-to-liquids plant in Sweetwater County, Wyoming in conjunction with Enron Corp.[22] ARCO has a license agreement with Syntroleum and began operation of a pilot plant of the GTL technology in Washington State in 1999.

Exxon operated a pilot-scale plant in Baton Rouge, LA from 1990 to 1993 and is studying application of GTL on the North Slope with data from that plant. In October in 1996, the Wall Street Journal reported that Exxon was holding talks with Qatar to build a GTL plant utilizing that country's vast natural gas resources. Although the project apparently fell through, a feasibility study of applying Exxon's Advanced Gas Conversion for the 21st Century (AGC-21) technology was completed jointly by Exxon and Qatar General Petroleum Corp. The plant was to produce 50,000 B/D of middle distillates and other oil based products from 500 million cubic feet of gas per day. Capital costs for the projects were estimated to be $1.2 billion – or $24,000 per daily barrel (DBL) of capacity. Exxon published limited details on its technology at industry meetings in 1994 and again in 1995.[23,24]

The Alaska Department of Revenue's brief comparison of six gas-to-liquid technologies is the sole source of information located for this report that gives details on the GTL process being explored by BP Exploration (Alaska).

5.2 Pipeline Transport of the GTL Product

Discussions with the Alyeska Pipeline Company were held in March of 1998 on the subject of transporting the GTL product through the trans-Alaska pipeline system (TAPS). The GTL product could either be slugged down the pipeline or shipped concurrently with the crude oil (mixed). Alyeska has done some calculations on how best to batch the GTL product through the pipeline, if the intent was to slug the product to avoid mixing with crude oil. Alyeska indicated that at high pipeline flow rates (around 1000 Mbbl/D or above), the mixing zone between the GTL product and the crude oil would be sufficiently small to minimize contamination of the GTL product. However, at lower flow rates, a pigging system could be used to mechanically separate the two fluids to minimize mixing during pipeline transport. Alyeska indicated that they have not publicly released any supportive documentation, but if there were a high probability of a GTL project on the North Slope, a report or paper would be issued.

5.3 Value of the GTL Product

The price of gasoline has averaged $8/bbl over the price of crude oil and diesel has averaged $6/bbl over crude oil over the past 10 years.[1] The product from Exxon's AGC-21 process produces a refinery feedstock free of most of the impurities found in conventional crude oil; being totally free of sulfur, nitrogen, nickel, vanadium, asphaltenes, multi-ring aromatics, and salt.[23] The product-upgrading step offers a flexible petroleum-product slate. When operated at relatively low severity, it maximizes feed to refinery catalytic cracking and lubricant production. At higher severity, all catalytic cracker feed boiling material can be eliminated, yielding up to 70% of the liquid product as jet and diesel fuel, with the remainder being naphtha. The process is not suitable for the direct production of gasoline; the major impact of this process is on the distillate (heating oil, jet fuel, and diesel) manufacturing industry, the petrochemical industry, and the lube industry.[25]

Because the GTL product is a high-quality refinery feedstock, it must pass through a refinery before becoming an end-use product such as diesel fuel or gasoline.[23] To arrive at an upper bound for the product value, we assume the GTL product is batched through the pipeline and is input into a refinery as a clean feedstock that produces equal amounts of gasoline and diesel. The prices for diesel and gasoline have historically been about $6.00/bbl and $8.00/bbl over world crude oil price respectively; therefore, the average premium of the refinery output would be $7.00/bbl over the world oil price. By subtracting an assumed gross refinery margin of $2.00/bbl[26] from the output price, the GTL product premium becomes $5.00/bbl over the world crude oil price.

The above methodology for obtaining an upper bound for the value of the GTL product ignores possible added value based on future sulfur regulations. Because the GTL product is totally free of sulfur, nitrogen, nickel, vanadium, asphaltenes, multi-ring aromatics, and salt, the gasoline and diesel produced from the GTL feedstock could be of greater value than gasoline and diesel produced from conventional crude oil. Therefore, the premium could conceivably be higher than $5/bbl.

To obtain a lower bound of the product value, it was assumed that the product is of lesser quality and is shipped together with the crude oil through TAPS and then refined. In this case, diesel or gasoline may not be the primary product and additional refining may be necessary. A lower bound for the GTL product premium could be as low as $1.50/bbl over the average price of world crude oil.

The GTL product's actual value most likely lies somewhere between $1.50 and $5.00 over the world crude oil price. For this analysis, $3.50/bbl is the assumed GTL product premium over world crude oil prices.

5.4 Capital Costs

In November of 1996, Salomon Brothers published a report on recent gas-to-liquids advances.[27] The majority of their report focussed on Exxon's process and Syntroleum's process. The report states that the capital cost of a GTL plant is roughly estimated at between $25,000 per daily barrel (DBL) capacity and $35,000/DBL, but suggest capital costs as low as $13,000/DBL are possible. Capital costs for Exxon's 50,000-B/D Qatar project were estimated to be $24,000 per daily barrel (DBL) of capacity.

The East-West Center in Honolulu, HI issued a bulletin, in early 1997 dealing with GTL technology.[28] The bulletin reported that Syntroleum did a study in 1995 of a 5,000-B/D plant on the U.S. Gulf Coast and calculated capital costs to be $27,000/DBL. It also stated that a more recent study for a second-generation design of 5,600-B/D capacity yielded an installed cost of $17,300/DBL. The bulletin further claimed that economies of scale associated with larger plants (30,000-B/D) could drive capital costs even lower, to the range of $12,000/DBL to $14,000/DBL on the Gulf Coast.

Capital costs for a generic GTL plant used in this evaluation are not taken from an operating GTL plant. There have been numerous reports of technological improvements and many studies indicating that GTL-plant capital costs have decreased to the mid-$20,000/DBL range and future reductions to the mid-teens are anticipated. Given these circumstances, capital costs for a generic GTL plant are assigned a value of $24,000/DBL, equal to the capital costs calculated in the Exxon/Qatar feasibility study mentioned above.

5.4.1 Capital Costs – Alaska North Slope

This section discusses differences in capital costs for projects constructed on the North Slope compared to projects constructed in the U.S. Gulf Coast area. Capital costs are higher on the North Slope because of a number of things. Large process plants are normally fabricated in the lower-48 and shipped to Alaska in sections on specialized barges. More steel is required in the modules for greater stability to be able to withstand the shipping process. Depending on the weather, delays of up to 30 days have occurred because of ice on the water. After the barges arrive and are unloaded, the sections must be assembled. Because of the severe weather, all equipment must be enclosed in insulated buildings with freezer-type doors. Everything must be designed for temperature extremes not seen in the Gulf Coast region. Labor costs are higher on the North Slope, as well, because living quarters have to be provided, labor rates are higher, and all food must be transported long distances.

When considering an installation on the North Slope, applying a capital cost factor of between 1.3 and 2.0 is reasonable for installations originally cost-estimated for the U.S. Gulf Coast area. A North Slope capital cost factor of 1.5 is used to calculate capital costs. Applying the 1.5 North Slope capital cost factor to the base value of $24,000/DBL for the generic GTL plant yields capital costs for a North Slope location of $36,000/DBL.

5.4.1.1 *Taking Advantage of the Learning Curve.* In 1989, E. W. Merrow of the Rand Corporation published a report for the U.S. DOE discussing cost improvements in chemical process technologies.[29] The indented paragraphs in this section are taken directly from that report.

> Cost improvement – sometimes called the *learning curve* or *progress curve* – plays a crucial role in the competitiveness of the U.S. chemical industry. More rapid cost improvement for a product, results in expanding market share and larger profits. Expectations of rapid cost improvement motivate companies to invest heavily in the development and introduction of new chemical products and processes, even if production from the first pioneer facility is economically marginal. The slope of the learning curve can also indicate whether government support of new chemical processes such as synthetic fuels can be expected to have large social benefits or to simply represent a net loss to the public treasury.
>
> After a successful development effort has produced the first commercial plant and product, the cost of the product from that plant may not be representative of the long-run costs.

The gas-to-liquids industry is essentially still in the R&D stages of development. The technology has been available since the 1930's; nevertheless, although there has been some production, it has been from subsidized or uneconomical plants. There has yet to be a "first commercial plant" upon which to base future cost improvements.

> A number of factors, all of which tend to occur over time, act in combination to decrease the costs of successive plants and product. These include:
>
> - Learning by plant operators and designers.
> - Technical improvement.
> - Economies associated th larger units.
> - Decreases in raw mater (feedstock) costs.
>
> The first factor is traditionally cited as the source of the 'learning curve.' It is important to note that we are not following strictly the learning curve concept that is common in the literature. Rather, we are making a distinction between the 'learning curve' – which is presumably caused by the learning process among workers, managers, and plant designers – and 'cost improvement' – an empirically observed phenomenon that may have many sources, including those of the traditional learning curve. We do not want to limit our attention to the learning phenomenon, so this analysis is concerned with the broad subject of cost improvement, defined as the reduction in a product's unit cost that occurs as the cumulative industry production increases.
>
> The rate of cost improvement can be described mathematically by the following equation.
>
> $$C_n = C_1 n^b, \quad (1)$$
>
> C_n = cost of the nth unit,

C_1 = cost of the first unit,
n = number of the unit being estimated, and
b = exponent equal to the log of the improvement-curve rate divided by the log of 2.

The cost improvement rate for organic chemical production was found to be 73.8 percent on the average, which means that for each doubling of cumulative organic chemical production, costs decline to 73.8 percent of what they were prior to that doubling.

Gas-to-liquids processes are included in the organic chemical production industry. The exponent "b" in Eq. (1) for the organic chemicals production industry is therefore:

$$b = \frac{\ln 0.738}{\ln 2.0} = -0.4383. \quad (2)$$

The 'cost of the nth unit' as given in the Rand report applies to the end-product cost. This cost is a function of capital costs, operating cost, feedstock cost, tax cost, etc. However, in this report, cost improvement is applied to capital costs instead of end-product cost. Our rationale for doing this is as follows: The two main costs that give rise to end-product cost improvements are capital costs and operating and maintenance costs. By applying the total cost improvement devised in the Rand report to the capital cost variable, we account for all the end-product cost improvement in one input variable – capital costs. While the resulting capital cost improvements might be too large using this methodology when looked at individually, they will be offset in the overall project economics by the non-improvements in other costs such as operating and maintenance costs.

In this report, we assume that there will be no other GTL production anywhere else in the world during the 30-year life of the GTL project except from this plant in Alaska, which is probably an unreasonable assumption. If the initial plant proves to be successful, other plants around the world would most likely be built, and cumulative GTL production would be accelerated, which, in turn, would accelerate the cost improvements for additional expansions in Alaska. This is not accounted for in the analyses in this report, which implies that the cost savings used in this report would be conservative and that actual cost savings could be greater than those used. However, by using this approach, we feel confident that the cost improvement defined in the Rand report is fully and adequately incorporated into this study.

The variable "n" in Eq. (1) refers to cumulative production. Each time the production capacity doubles, "n" is increased by one unit. Assuming the capital costs of the first GTL plant on the North Slope are \$36,000/DBL as discussed in Section 5.4.1, the capital costs for a second plant of equal size would be reduced to \$26,568/DBL according to Eq. (1) because the capacity is doubled. A third plant of equal size would increase the capacity by an additional 50 percent; thus, the variable "n" in Eq. (1) for the third plant would be 2.5, and the cost of the plant would be \$24,093/DBL. The addition of the fourth plant would achieve the next doubling of capacity and "n" equals 3 for the fourth addition; and the cost would be \$22,292/DBL. The cost of the fifth addition of 60,000 bbl/D of capacity would be \$21,475/DBL.

6. ECONOMIC EVALUATIONS

6.1 Economic Input Variables

The LNG project evaluated here was described in detail in the 1996 DOE report and was not revised for this study except for two exceptions: values were updated from 1995 dollars to 1998 dollars and the oil price forecast was changed. The GTL project was changed to include capital cost improvements;

data learned from the Rand report cited earlier; as well as updating costs from 1995 dollars to 1998 dollars. The Prudhoe Bay field model was revised and updated to include changes in costs, future investments, and production forecasts

6.1.1 Oil Prices

Several oil price forecasts are available for use. The world oil price forecast that is used as the "base" case in this study is an $18/bbl flat price (in 1998 real dollars). The Energy Information Administration (EIA) publishes an Annual Energy Outlook (AEO) every year in which they publish a set (high, low, and reference) of oil price forecasts. The EIA projects the AEO98 reference price forecast to the year 2020. Historical world crude price as well as the projected AEO98 oil price forecast are shown in Fig. 6. This forecast increases slightly throughout the forecast period in terms of real dollars. For economic evaluations beyond the forecast period, a linear extrapolation was used.

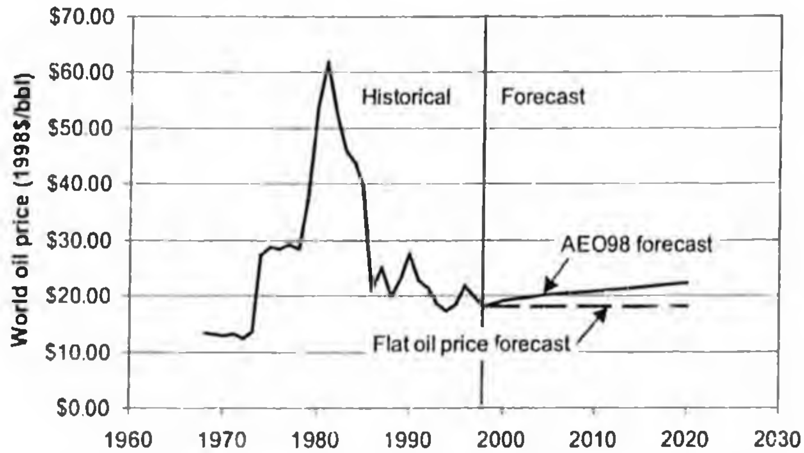

Figure 6 - Historical and forecast world oil prices. Data from Energy Information Administration.

Oil prices, since 1986, on the average have remained relatively flat at around $20/bbl or slightly declined. The projects being evaluated in this study are long-term projects – ending between 2036 and 2042. Oil prices will certainly vary somewhat during this period with normal vicissitudes. Although a flat oil price of $18/bbl may seem high or low depending on when this report is read, an $18/bbl oil price appears reasonable over the length of these evaluations. In addition, a flat oil price allows comparisons with other projects without the added variable of time-dependent oil prices.

6.1.2 Inflation

Inflation is the persistent rise in the prices of a Consumer Price Index type basket of goods, services, and commodities. In the USA and many other countries, this 'basket' is called the Consumer Price Index (CPI), which is made up of about 400 goods and services and commodities purchased by typical consumers.[30] The U.S. Department of Labor, Bureau of Labor Statistics prepares the CPI on a monthly basis. The seasonally adjusted CPI for all urban consumers is plotted in Fig. 7. Historically, although the annual inflation rate has fluctuated dramatically at times, it has remained below 15% since 1940. Since the early 1980's, it has varied between 1% and 7%. In Fig. 7, the average annual inflation rate over the last ten years of 3.0%/yr has been extrapolated over the approximate length of the projects evaluated. The future annual inflation rate used in the economic evaluations in this report was 3.0%/yr.

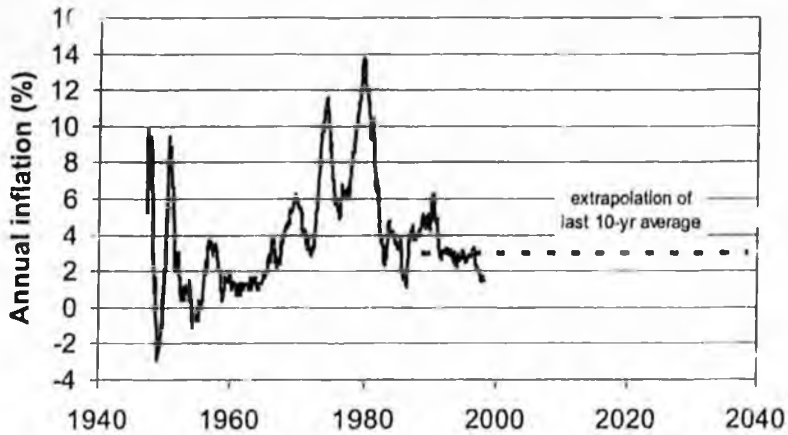

Figure 7 - Historical and projected annual inflation rate.

6.1.3 Discount Rate

The discount rate used in discounted cash flow analyses can be defined as the expected rate of return (ROR) that could be realized on similar alternative investments with equivalent risk. The minimum acceptable discount rate for new projects will vary for different projects and for different companies depending on the risk associated with the project, the economic climate of the nation, and the alternative investment opportunities for a given company. The major developments on the North Slope including the Prudhoe Bay field and TAPS have multiple owners with varying ownership levels and competing interests, which makes it impossible to select a discount rate representative for each company. However, an average or representative value of 10% is selected for the analyses of this study.

6.1.4 Taxes

The evaluations are performed on an after-tax basis. Alaska's corporate income tax, like that of most other states, is based on apportioning either domestic or worldwide income to establish the "deemed" Alaska income subject to the state nominal tax rate of 9.4%. The apportionment fraction is the average amount of the taxpayer's property, hydrocarbon extraction, and sales in Alaska relative to that in the rest of the world. To precisely assess the state's income tax, it is necessary to anticipate what the investor's worldwide income, worldwide property, worldwide extraction, and worldwide sales with be throughout the life of the project; this is obviously impossible. To approximate the state income tax paid on project earnings, the nominal tax rate is halved to 4.7% and applied to all taxable income.

The federal income tax rate used in the analysis is 35%.

6.2 Method of Economic Evaluation

After-tax discounted cash flow analysis was used to evaluate the gas sales options. The net present value of a project resulting from this analysis is used to compare the options. The term *cash flow* refers to the net inflow (revenues, savings) and outflow (operating costs, taxes, capital expenditures) of money that occurs during a given year. If costs exceed revenues, then the cash flow is negative for that year and, of course, if revenues exceed costs, then the cash flow will be positive for that year. The cash flows for each year the projects are evaluated are *discounted* to year zero to account for the time value of money. Hence, the term *discounted cash flow.* The rate at which future cash flows are discounted is known as the discount rate and is discussed in section 6.1.3.

The projects are quantified in terms of the net present value. The net present value (NPV) of a project is the sum of all the yearly discounted cash flows. It includes all investments, revenues, and costs of a project. The real utility of the NPV analysis is that it rolls the entire project into a dollar value that can be compared to other projects regardless of project length or timing. It enables investors to fairly and to properly compare projects and to determine which project has the greatest worth in today's dollars.

The term NPV_{10} is used to signify a net present value evaluated at a 10 percent discount rate. By definition, a project that produces a NPV_{10} equal to $0 has a rate of return equal to 10 percent. Therefore, a project with a positive NPV_{10} produces a rate of return greater than 10 percent, while a project with a negative NPV_{10} produces a rate of return less than 10 percent.

An economic model that incorporates the effect of gas sales, as well as oil sales, was developed to evaluate the Prudhoe Bay field. The Prudhoe Bay field is by far the largest current natural gas source on the North Slope with 21.8 Tcf of natural gas estimated to be available for a future major-gas sale (see section 2.3.7). Point Thomson may have as much as 5 Tcf available for sale according to recent estimates, with other fields offering much smaller amounts. Because Point Thomson is not a producing field and there are major concerns about its economic viability,[1] an economic model for the Point Thomson unit was not constructed in this study. However, gas from the potential production of Point Thomson, or other fields, can be included in the total amount of gas sold to a gas project.

IFPS/Plus™ ver. 5.1[b] was the commercial software used to perform the economic evaluations. This software allows a basic economic model to be constructed and run with a number of data files representing different cases or projects. To evaluate gas sales from the North Slope, two different models were constructed: the Prudhoe Bay field model and the gas project model (the GTL plant, for example).

The Prudhoe Bay field model was run with three different data files along with a transportation module.

1) The base case data file supplies data to the Prudhoe Bay field model to evaluate the economics of the field with no major gas sales in the future. Current field practices are continued in this case with the produced gas processed and used for miscible injectant and pressure maintenance to continue the highly effective oil-recovery processes in the field, but not sold.

2) The PBU-GTL data file supplies data to the Prudhoe Bay field model to evaluate the economics of the field with major gas sales to a GTL plant.

3) The PBU-LNG data file supplies data to the Prudhoe Bay field model to evaluate the economics of the field with major gas sales to an LNG project.

4) The transportation module calculates the transportation costs associated with transporting liquids through TAPS.

The gas project model was developed to evaluate the economic viability of a gas commercialization project, either an LNG project or a GTL project. The model can be run with either the LNG data file or the GTL data file. The LNG data file supplies data to the gas project model on the LNG project and accepts gas from Prudhoe Bay, Point Thomson, or another field(s). The GTL data file provides data to

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[b] A Comshare, Inc. product.

the gas project model on the GTL plant and also accepts gas from Prudhoe Bay, Point Thomson, or another field. The transportation module is used with the GTL data file to calculate transportation costs of the GTL product; however, the transportation module is not used when evaluating the LNG project because no liquids are being shipped through TAPS.

Fig. 8 illustrates the relationships between the two economic models and the data files used in conjunction with those models.

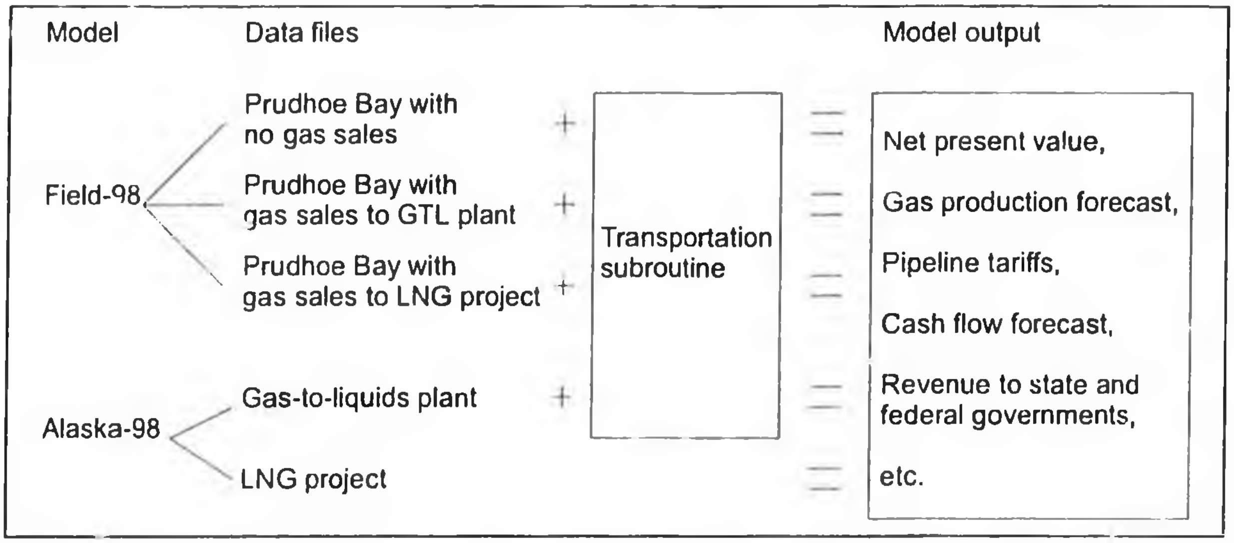


Figure 8 - Flow chart describing economic evaluations and relationships between data files and models.

6.2.1 Relationship between Prudhoe Bay and Gas Project

Both the field model and the gas project model are necessary to effectively evaluate the scenarios being considered and are tied together by the price of natural gas. The "natural gas sale price" for the field operators' model is equal to the "natural gas feed price" in the gas project model and is termed the gas transfer price. The gas transfer price is calculated with the use of the "net back" term. The "net back" refers to the 'net' fraction of the gas price sold by the gas project (GTL plant or LNG project) that is returned 'back' to the Prudhoe Bay unit operators as payment for the gas. For the LNG project, the North Slope gas transfer price in \$/MCF is calculated by the following equation.

$$\textit{Gas transfer price} = \textit{LNG price in Asia} \times \textit{net back}. \tag{3}$$

If the East Asia LNG sale price were \$3.50/Mcf, a net back of 0.20 means that the Prudhoe Bay operators would receive 20% of \$3.50 or \$0.70/Mcf for the gas they sell to the project.

For the GTL plant, the North Slope gas price in \$/Mcf is calculated by

$$\textit{Gas transfer price} = \textit{GTL product price on North Slope} \times \frac{\textit{BTU of natural gas}}{\textit{BTU of GTL product}} \times \textit{net back}. \tag{4}$$

If the North Slope GTL product price were $16/bbl, the natural gas BTU content were 1.150 MMBTU/Mcf, the GTL product BTU content were 5.75 MMBTU/bbl, and the net back were 0.20, then the North Slope gas transfer price would be $0.64/Mcf.

6.3 Results of Economic Evaluations

6.3.1 Scenarios Evaluated

6.3.1.1 Prudhoe Bay Unit Scenarios. No major gas sales. Continue with current operations utilizing the natural gas to maximize oil production. Under this scenario, oil production continues until 2025, when the economic limit of the field is reached.

Major gas sales to a gas-pipeline/LNG project beginni.. in 2005. Maximum gas production from Prudhoe Bay of 2.0 Bcf/D is reached in 2009 after increasing the gas production rate by 20% of the maximum per year. Ultimate oil recovery is 400 million bbl less in this scenario than in the "no major gas sales" scenario.

Major gas sales to a fast-paced GTL plant located on the North Slope beginning in 2005. This scenario follows the same gas sales rate schedule as the "sales to LNG" scenario. Ultimate oil recovery is 400 million bbl less in this scenario than in the "no major gas sales" scenario.

Major gas sales to a fast-paced GTL plant located in southern Alaska beginning in 2005. This scenario is identical to the previous scenario except an extra cost is added to natural gas sold to account for transporting it from the North Slope to southern Alaska through an 800-mile pipeline.

Majoi ;as sales to a slow-paced GTL plant located on the North Slope beginning in 2005. The gas production rate from Prudhoe Bay begins at 0.5 Bcf/D for 5 years and then increases to 1.0 Bcf/D for another 5 years, and so on until a maximum of 2.0 Bcf/D is reached in 2020. Under this assumption, ultimate oil recovery will be equal to the "no major gas sales" scenario.

6.3.1.2 Natural Gas Pipeline/LNG Scenario. A potential natural gas pipeline/LNG project was evaluated to accept 2.0 Bcf/D of natural gas sales from the Prudhoe Bay unit as well as 0.5 Bcf/D from the Point Thomson unit, which lies 50 miles east of Prudhoe Bay.

6.3.1.3 Three Scenarios Evaluated for Potential GTL Plant. A fast-paced GTL scenario where a 300,000-ʀ/D GTL plant is constructed on the North Slope to match the timing and volumes proposed by in the LNG scenario.

A slower-paced GTL construction schedule is as. umed to take advantage of the learning curve associated with implementation of newer technologies. : acement is on the Alaska North Slope and this scenario is paired with the fourth scenario for the Prudhoe Bay unit – "major gas sales to slow-paced GTL plant." The GTL plant purchases natural gas from Prudhoe Bay at a maximum rate of 2.0 Bcf/D and from Point Thomson, as well, at a rate of 0.5 Bcf/D.

A 300,000-B/D GTL plant (fast-paced) is located in Valdez, AK. This scenario assumes that the natural gas pipeline is built and a tariff is charged to the gas passing through the line. The assumed gas purchase rate is equal to the LNG scenario. A lower capital-cost factor (1.2) is applied at the Valdez location as opposed to a North Slope location (1.5).

The pipeline tariff of $0.80/Mcf was calculated for the third GTL scenario using two independent methods. The first method used the following simple formula developed by the Alaska Department of Revenue to estimate field pipeline tariffs.[31]

$$\text{Pipeline tariff} = \frac{\text{Cost of pipeline (\$)}}{\text{total volume to be transported (Mcf)}} \times 3.35 \qquad (5)$$

The cost of a natural gas pipeline has been estimated to be $6 billion. The total volume of gas transported through the pipeline from PBU and PTU to Valdez is 25 Tcf. A pipeline tariff of $0.80 is calculated using Eq. (5).

The other method used to calculate the gas pipeline tariff at Valdez was through amortizing the capital costs of the pipeline to get an approximate yearly cost and then dividing by the yearly rate. This method yields a natural gas pipeline tariff of $0.77/Mcf, which is comparatively close to the tariff calculated from Eq. (5). A tariff of $0.80/Mcf is used in the economic evaluations of this scenario.

6.3.2 TAPS Tariff Discussion

The tariff that is charged for transporting liquid through the Trans-Alaska Pipeline System (TAPS) is an important economic parameter. The tariff calculation is based on costs to operate the pipeline, future investments, pipeline profit, and liquid flowrate through the pipeline. TAPS tariffs are a very important part of an analysis of projects affecting liquid production from the North Slope of Alaska. The same tariff is applied to all liquids passing through the pipeline; whether it be crude oil, natural gas liquids, or product from a GTL plant. The tariff is deducted from value of the crude oil or GTL product at downstream refineries. A higher transportation tariff reduces the value of the wellhead product.

Fig. 9 shows the differences in TAPS tariff forecasts for four scenarios described in section 6.3. All of the four scenarios share the same TAPS tariff from 1998 through 2004 because no gas is sold and no extra liquids are produced during that time.

The LNG option tracks the no-gas-sales option until 2009 when the Pt. Thomson unit begins oil and gas production. At this point until 2016, the TAPS tariff is slightly lower for the LNG option than the no-gas-sales option. After 2016, the oil production rate from PBU declines because of the unavailability of gas for EOR and offsets the additional production from PTU, which causes the tariff for the LNG option to rise above the no-gas-sales option. After 2021, the TAPS tariff for the LNG option rises dramatically when oil production from PBU is expected to cease.

In 2005, both GTL options begin to produce GTL liquids from the converted natural gas, reducing the TAPS tariff relative to the no-gas-sales option. The fast-paced GTL development produces more liquids initially than the slow-paced development and Pt. Thomson is developed sooner, which combine to reduce the tariff more rapidly because of the higher volume of liquid flowing through the pipeline. However, after 2022, the slow-paced development enjoys a lower TAPS tariff because of changes in oil production from PBU. In the fast-paced development, PBU stops producing crude oil in 2021, while the unit continues to produce oil until 2025 in the slow-paced scenario. Also, Pt. Thomson begins production of the GTL product and natural liquids beginning in 2025, which helps keep the tariff lower for the slow-paced GTL development.

Besides improving the economics of the Prudhoe Bay and the Point Thomson units, lower TAPS tariffs positively impact the economics of all other oil producing fields that transport liquids through the trans-Alaska pipeline system. The benefit of lowering TAPS tariffs because of the addition of GTL products to these other fields is not quantified in this report, but is expected to be significant as a whole.

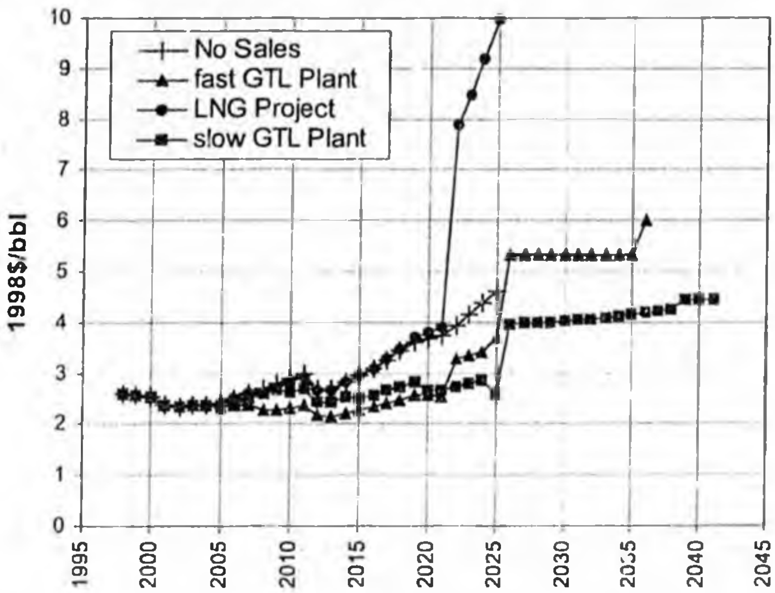


Figure 9 - TAPS tariff forecasts in 1998$ for four scenarios.

6.3.3 Results

Results of the economic evaluations are best represented by the net present value of the project. The term NPV_{10} represents the net present value evaluated at a discount rate of 10%. Table 1 shows the results of the evaluations described above. Project economics (meaning the sum of the field and gas marketing scheme) of all the scenarios are linked together by way of the natural gas price or gas transfer price. The gas transfer price for each scenario was optimized between the gas seller (PBU) and the gas buyer (gas marketing scheme) by varying the net back fraction until the combined NPV_{10} was maximized.

Table 1. Economic evaluations of major gas sales from the North Slope of Alaska.

Scenario	Entity	NPV_{10} ($, millions)
Major gas sales to gas-pipeline/LNG-plant	Incremental Prudhoe Bay unit	589
	Gas-pipeline/LNG-plant	-2,991
	Total	-2,402
Major gas sales to GTL plant on North Slope (fast-paced)	Incremental Prudhoe Bay unit	914
	GTL plant	-1,297
	Total	-383
Major gas sales to a GTL plant in southern Alaska (fast-paced)	Incremental Prudhoe Bay unit	542
	GTL plant	-1,908
	Total	-1,366
Major gas sales to GTL plant on North Slope (slow-paced)	Incremental Prudhoe Bay unit	-113
	GTL plant	945
	Total	832

In the evaluation of scenarios involving the Prudhoe Bay unit, low net back fractions can cause cash flows to become negative after oil operations cease. In cases such as these, only net back fractions that were high enough to keep Prudhoe Bay yearly cash flows positive were evaluated. Table 1 shows the results of the economic evaluations. The net present value of the incremental Prudhoe Bay unit given in Table 1 is simply the difference between the NPV_{10} of the Prudhoe Bay unit without any gas sales and the NPV_{10} of the Prudhoe Bay unit with major gas sales. A negative incremental NPV_{10} indicates that the Prudhoe Bay unit is worth more if the gas is not sold.

6.3.4 Discussion of Results

Evaluation of the Prudhoe Bay unit economics for the gas sales scenarios required the comparison of the economics of the each gas sales scenario with the economics of the base scenario (no major gas sales). If the NPV_{10} of PBU with a gas sales option is positive, but still less than the base scenario, then, obviously, it would make economic sense from the PBU operator's point of view to not market the gas. The 'incremental Prudhoe Bay unit' in Table 1, represents the difference between the NPV_{10} of the Prudhoe Bay unit with major gas sales and the NPV_{10} of the Prudhoe Bay unit with no major gas sales.

The economic results shown in Table 1 were achieved by varying the net back until the combined NPV_{10}'s of the Prudhoe Bay unit and the gas marketing scheme (total scenario economics) reached a maximum. This approach assumes that the total scenario economics are maximized with the only constraint being that the Prudhoe Bay unit have a positive cash flow while production operations were ongoing.

The net back is a variable that sets the transfer price for the natural gas between the producer and the buyer (LNG project or GTL project), and is explained in section 6.2.1. The gas transfer price is a key variable in the economic evaluation of both the Prudhoe Bay field and the gas-marketing scheme. In this analysis, the transfer price is consistent within each scenario; that is, the gas producer sells the gas at the same price that the LNG or GTL project buys it.

Because the transfer price is a *negotiated* percentage of the product sale price it will be different for each scenario. A higher net back or transfer price increases the gas sales price on the North Slope and means higher profits for the Prudhoe Bay unit and lower profits for the gas-marketing project. A lower net back means lower profits for the Prudhoe Bay unit and higher profits for the gas-marketing project because North Slope gas price is lower. Figures 10, 11, 12, and 13 show how the project economics varied with respect to the net back.

Of the four gas sales scenarios (see Table 1), the slow-paced North Slope GTL development scenario is the only one with a positive incremental combined net present value using a discount rate of 10%. A negative NPV_{10} does not necessarily mean that a project loses money; it simply means that the rate of return for that scenario is less than 10% (the discount rate). A lower discount rate may show positive net present values for some or all the scenarios; however, this dependence was not quantified.

The gas sales revenues of slow-paced North Slope GTL plant are realized later in the life of this scenario than in the fast-paced GTL scenarios and the LNG scenario, which tends to decrease the net present value of the project. However, the savings in capital costs associated with the "learning curve" that are incorporated into this option outweigh the added discount in revenue caused by delaying the gas sales.

The total scenario for the GTL plant at a southern Alaska location includes the Prudhoe Bay unit, a gas-pipeline/LNG project, and a GTL plant in southern Alaska. This placement for the GTL plant allows some *potential* advantages compared to a North Slope location. (In this case, the capital cost investment follows the same schedule as the fast-paced GTL plant development.) The capital cost factor

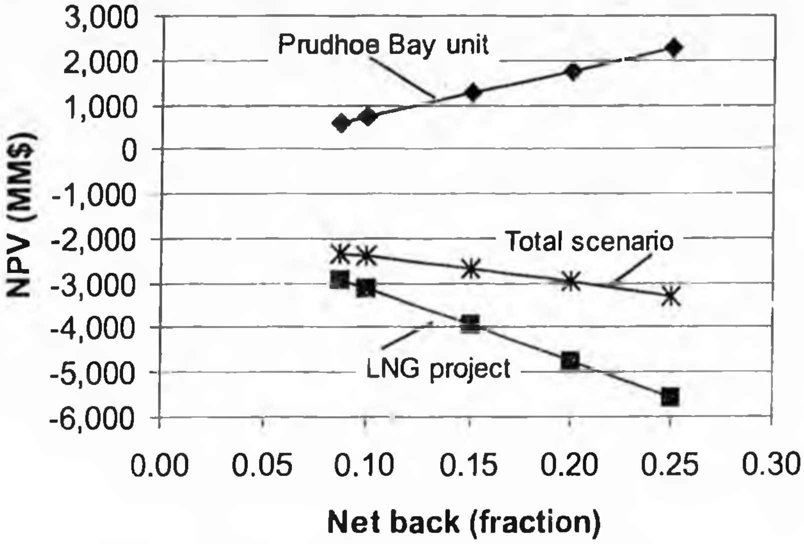


Figure 10 – NPV calculations for gas sales to LNG scenario.

would be less for a southern location than for the North Slope because of reduced shipping, labor, and materials costs. In the economic evaluation, the capital cost factor was lowered from 1.5 (for the North Slope location) to 1.2. The other major change in evaluations is the additional price of the natural gas at Valdez. The $6 billion gas pipeline transporting natural gas from the North Slope to Valdez would still be constructed; adding about $0.80/Mcf to the gas feed cost (see section 6.3.1.3 for more detail). However, the additional cost of the natural gas feed more than offsets the reduced capital costs associated with the Valdez location.

The LNG scenario evaluated here is the same as in the 1996 DOE report except that the costs were updated from 1996 dollars to 1998 dollars and the $18/bbl flat oil price forecast was used instead of the forecast used in the 1996 study. We did not include possible cost savings in pipeline construction nor

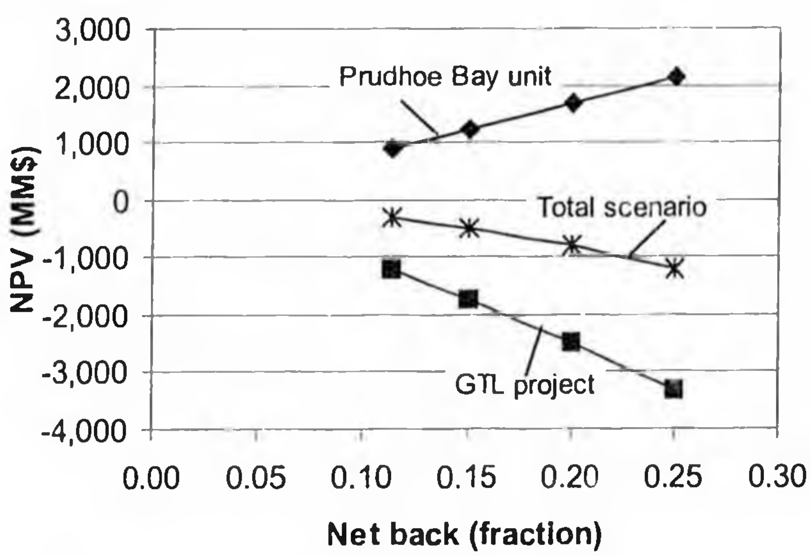


Figure 11 - NPV calculations for gas sales to a North Slope GTL plant (fast-paced) scenario.

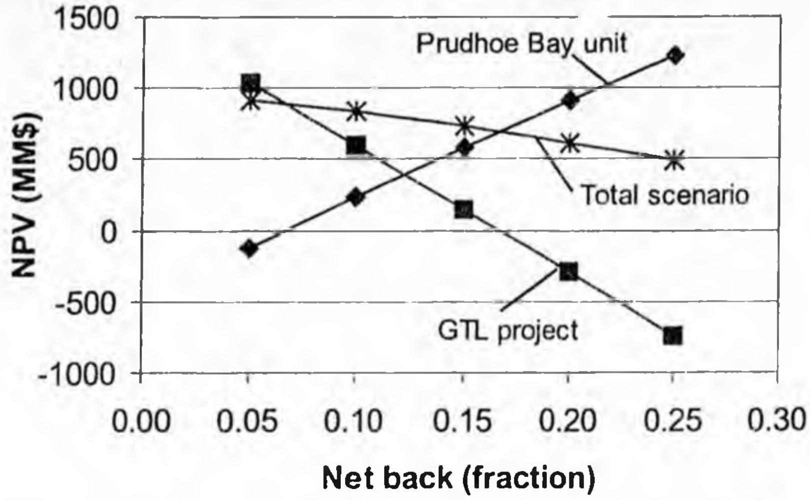


Figure 12 - NPV calculations for gas sales to a North Slope GTL plant (slow-paced) scenario.

did we include the possible effects of the Stranded Gas Act, which could reduce tax payments in the earlier portion of the project.

We left the LNG scenario unchanged from the 1996 DOE report with the exception of the oil price forecast and updating costs from 1996 dollars to 1998 dollars because it provided a base point to compare advances in GTL technology. In the 1996 DOE study, the evaluation of the LNG option and the fast-paced GTL option resulted in relatively equivalent economic scenarios. However, the fast-paced GTL development scenario that includes technological and cost improvements now has a decided advantage over the LNG scenario. When the added cost improvements associated with the learning curve are included, the slow-paced GTL development scenario is even more attractive. We should note, however, that potential cost savings in the LNG scenario (see section 3) were not included in the economic evaluation of this scenario. In addition, potential tax savings associated with the Alaska Stranded Gas Devel-

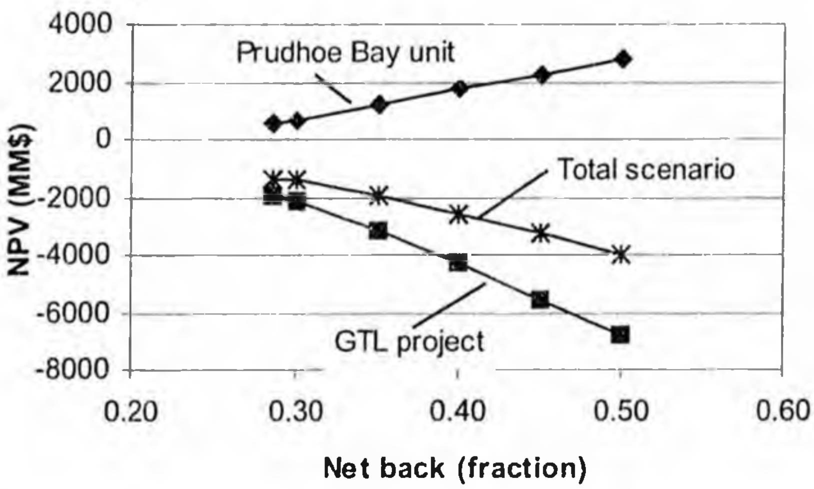


Figure 13 – NPV calculations for gas sales to a GTL plant (fast-paced) in southern Alaska.

opment Act (see section 4) were not included in the economic evaluation.

6.3.5 Sensitivity Analyses

There are many sensitivity analyses that could be run on these evaluations. Learning the ramifications of varying input parameters is important to understanding project economics. As this study was primarily concerned with economics of gas-to-liquids technology Alaska, sensitivities were performed only on the GTL plant portion of the total scenarios. The field portion of the scenarios was not further included in the sensitivity analyses. The object of the analysis was to determine which input parameters cause the greatest effect on project economics. This information is vital in determining those parameters that offer the greatest potential for increasing or decreasing economic viability. These parameters require the most attention and are natural targets for further study by increasing research efforts.

The parameters selected for the sensitivity analysis were:

- Capital costs for a GTL plant on the Gulf Coast
- World oil price
- North Slope cost factor applied to capital costs
- Premium of the GTL product over crude oil prices
- Operation and maintenance costs of GTL plant
- Rate of cost improvement on subsequent GTL plant capacity
- Federal income tax rate
- Total GTL plant efficiency
- Natural gas feed BTU content per cubic foot
- Alaska state income tax rate
- GTL product BTU content per barrel

Fig. 14 shows the result of a sensitivity analysis of the input data for the slow-paced GTL plant development. The input parameter that influences the economical output is that with the longest bar and is placed at the top of the plot; while the parameter with the least influence is placed at the bottom. The numbers on each end of the respective horizontal bars indicate the possible range of the variable in ques-

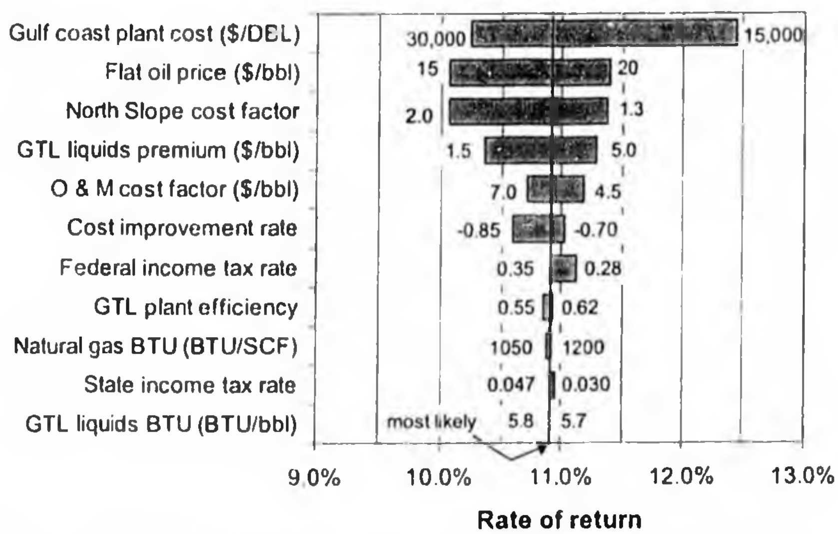


Figure 14 - Sensitivity of input parameters with respect to project economics for the slow paced, staged GTL development scenario.

tion. The vertical "most likely" line on the figure indicates the default value for each variable.

Each input parameter was varied separately and independently from the other parameters and, therefore, the horizontal bar represents the range in ROR caused by varying only that particular variable. For example, as the world crude-oil price rises from a flat $15/bbl to $20/bbl, the ROR of the Alaskan GTL project increases from 10.1 percent to 11.4 percent. The four most critical variables are the Gulf Coast GTL plant cost, the world oil price, the North Slope cost factor, and the GTL liquids per barrel premium. The ROR using the most likely values for each of the variables is 10.9 percent as shown in Fig. 14.

6.3.6 Monte Carlo Analysis

The Monte Carlo simulation technique permits a "probabilistic analysis" of project economics by applying probability distributions to the input parameters. Probabilistic sensitivity analyses do not compute a single result, but instead, the outcome is a range over which the results vary. In some investment situations, the shape of the computed curve is more important than the most expected value. For example, a project with an expected ROR of 20 percent with a very wide distribution might be considered less desirable than a project with an expected ROR of 15 percent and a very narrow distribution.

A basic tool of probability theory is the use of a range of values to describe input variables that cannot adequately be quantified by single value estimates. For example, the determination of the least, greatest, and most likely values of a variable will more accurately quantify a variable than will the average value.

Of the many possible distributions to describe input variables, the triangular distribution is perhaps the easiest distribution to employ. It requires an estimate of the minimum expected value, the maximum expected value, and the most likely value. Fig. 15 illustrates the form of this distribution.

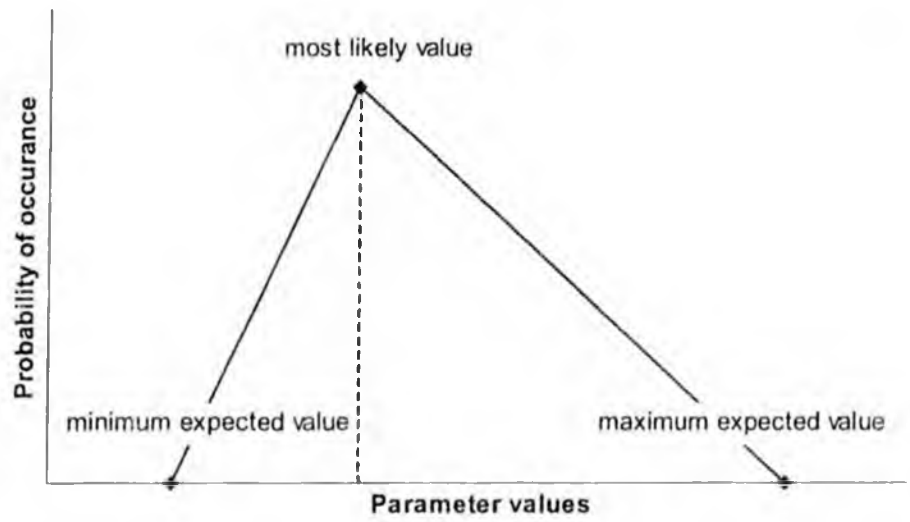


Figure 15 - Example of a triangular distribution of an input variable for Monte Carlo analysis.

In this Monte Carlo analysis, the probability distributions for all the input parameters are modeled using triangular distributions. The possible range of values for GTL plant located on the U.S. Gulf Coast was discussed in section 5.4. The world oil price forecasts and variations are discussed in section 6.1.1. The capital cost factor applied to projects for placement on the North Slope of Alaska is discussed in section 5.4.1. The premium over the price of crude oil applied to the GTL product is discussed in section 5.3. Operation and maintenance (O & M) costs for large plants such as a GTL plant can be effectively approximated on a cost-per-output-barrel basis. The most likely value for O & M costs used in this analysis is $6/bbl, with a minimum of $4/bbl and a maximum of $7/bbl. The rate of cost improvement for successive GTL plants is discussed in section 5.4.1.1. The maximum expected values for federal and state income taxes are equal to the most likely values of 0.35 and 0.047 respectively. The minimum expected values were taken to be 80% of the most likely values; or, 0.28 for federal and 0.03 for the state. The efficiency of a GTL plant is estimated to be 60% (most likely) with a minimum of 55% and a maximum of 62%. The BTU content of the natural gas feed and the GTL product were previously discussed by Thomas et al.[1] Table 2 tabulates the minimum, maximum, and most likely values for the input parameters varied as part of the Monte Carlo analysis.

Table 2. Minimum, maximum, and most likely values for triangular distributions used in Monte Carlo analysis.

	Minimum expected value	Most likely value	Maximum expected value
Gulf coast plant cost ($/DBL)	15,000	24,000	30,000
Flat oil price ($/bbl)	15	18	20
North Slope cost factor	1.3	1.5	2.0
GTL liquids premium ($/bbl)	1.5	3.5	5.0
O & M cost factor ($/bbl)	4.5	6.0	7.0
Cost improvement rate	-0.70	-0.74	-0.85
Federal income tax rate	0.28	0.35	0.35
GTL plant efficiency	0.55	0.60	0.62
Natural gas BTU (BTU/SCF)	1050	1150	1200
State income tax rate	0.030	0.047	0.047
GTL liquids BTU (BTU/bbl)	5.70	5.75	5.80

In a Monte Carlo analysis, a value is calculated for each distributed input variable from random numbers. Then, using the randomly selected parameter values, the ROR is calculated. This process is repeated, picking a new set of random numbers to determine the ROR of the project. For this analysis, the ROR was calculated repeatedly (10,000 iterations) to get a smooth rate-of-return distribution.

6.3.6.1 Results of Monte Carlo Analysis. Fig. 16 is a plot of the probability-of-occurrence versus rate-of-return for a slow-paced GTL plant development on the North Slope. Fig. 17 was obtained by plotting the cumulative probability of the ROR outcome. From Fig. 16, possible rates of return can range from 8.7 percent to 13.1 percent. However, from Fig. 17, a 90 percent confidence interval on the rate of return of between 9.8 percent and 11.9 percent can be obtained by picking the 5 percent and 95 percent cumulative probability with their corresponding rates of return. The median value of 10.8 percent indicates that half of the time, a rate of return calculation would return a value of 10.8 percent or greater.

The median ROR of 10.8 percent is slightly lower than the 10.9 percent ROR calculated when using the most likely values for the input parameters. This difference occurs because the triangular distributions of most of the input parameters are skewed. For example, the flat-oil-price input variable ranges from 15 to 20, with 18 being the most likely. However, the average value of the distribution is actually 17.67, which is slightly less than the most likely value of 18. The standard deviation is 0.7 percent, which demonstrates that the results are tightly centered on the average of 10.8 percent.

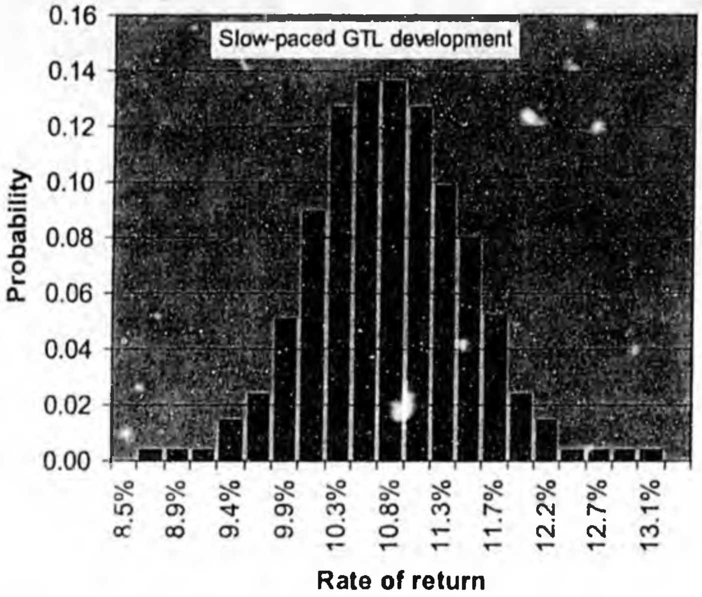


Figure 16 - Frequency plot of the rate of return for a slow-paced GTL plant development after 10000 iterations.

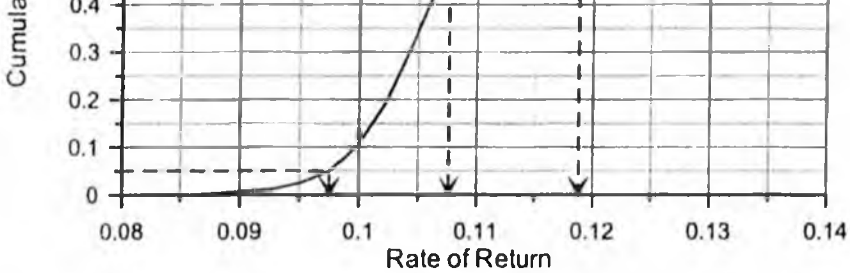


Figure 17 - Cumulative probability of occurrence for the rate of return of a slow-paced GTL plant development.

7. SUMMARY

The Alaska North Slope has a vast natural gas resource that is currently being used to enhance oil recovery. It is estimated that the Prudhoe Bay field alone will have 21.8 Tcf of natural gas available for sale after oil operations cease. Currently, there are two broad schemes proposed for commercializing the natural gas on the North Slope. One is the proposed gas-pipeline/LNG-plant scenario; the other converts the natural gas to syn-crude in a North Slope GTL plant, eliminating the need for an additional pipeline from the North Slope.

The purposes of this report were to investigate and explore the effect of applying new technology to the economics of a proposed GTL plant, to evaluate the potential of a slower-paced deployment of GTL technology, and to evaluate the effect of GTL plant placement on economics.

Of the gas marketing scenarios evaluated, results indicate that the slow-paced GTL scenario is the only one with a rate of return greater than 10 percent. The other scenarios did not show positive net present values under the economic conditions selected for the simulations. Their rank, in order of net present value, is as follows: slow-paced GTL development, no-major-gas-sales, fast-paced GTL development, fast-paced GTL development in southern Alaska, and finally a gas-pipeline/LNG project.

The slow-paced GTL development would allow cost savings on subsequent expansions. These assumed savings along with the lowering of the transportation tariff combine to distinguish this option for marketing the North Slope gas from the other scenarios. Critical variables that need further consideration include the GTL plant cost, the GTL product premium, and operating and maintenance costs. Reducing these costs or increasing the premium could dramatically increase the profitability of the GTL process. Understanding these variables better and reducing their uncertainty would allow a more accurate prediction of economic profitability. Further study of these variables (GTL plant cost, GTL product premium, and O & M costs) is recommended. In addition, a study to quantify the benefit of a tariff reduction caused by a North Slope GTL plant to the economics of other fields (besides Prudhoe Bay) is also recommended.

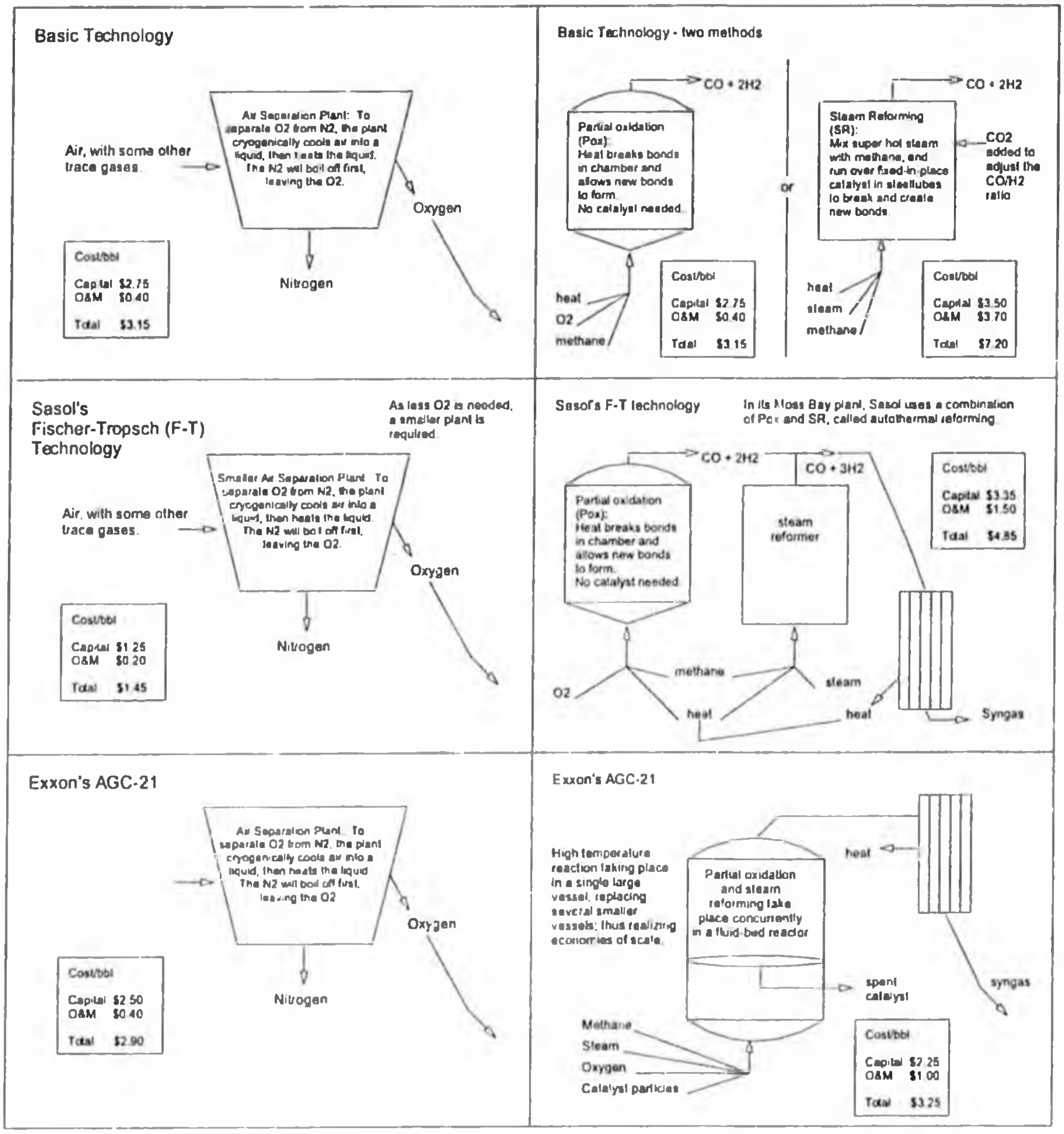
8. APPENDIX

Comparison of Six Gas-to-Liquids Technologies[c]

[c] Based on information provided by the Alaska Department of Revenue.

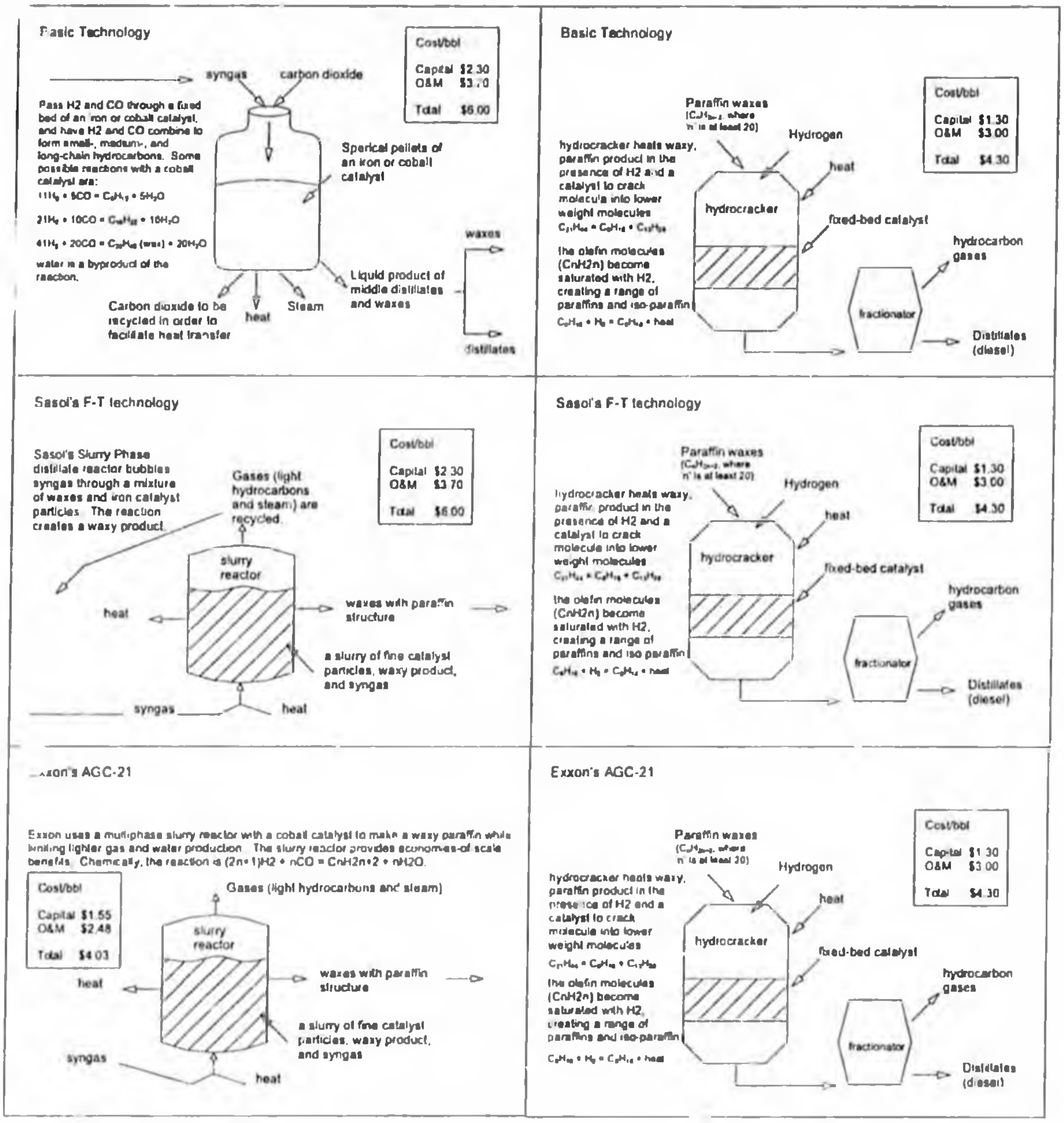
Step One: Oxygen getting

Step Two: Syngas generation



Step Three: Fischer Tropsch synthesis

Step 4: Product Upgrading



Step One: Oxygen getting

BP's compact steam reformer

BP does not need an air separation plant to make oxygen because it generates syngas using only steam methane reforming (SMR)

Cost/bbl	
Capital	$0.00
O&M	$0.00
Total	$0.00

Syntroleum's Nitrogen-diluted GTL technology

Syntroleum does not need an air separation plant because it uses air rather than oxygen to generate syngas.

Cost/bbl	
Capital	$0.00
O&M	$0.00
Total	$0.00

Department of Energy's Ceramic Membrane technology

DOE's technology does not requre an air separation plant since it separates oxygen from the other components of air at the same time as it generates syngas

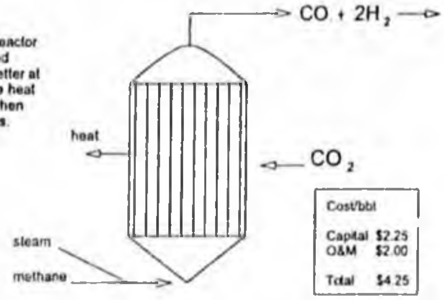
Cost/bbl	
Capital	$0.00
O&M	$0.00
Total	$0.00

Step Two: Syngas generation

BP's compact steam reformer

BP removes heat from within the reactor's steel tubes, thereby allowing for a more compact design

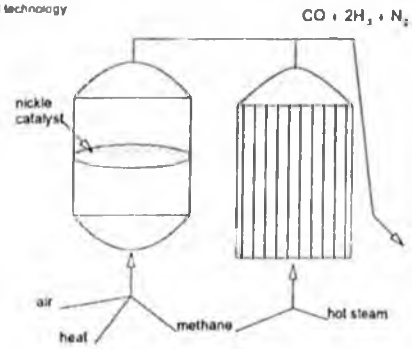
The steam reactor with fixed bed catalyst is better at removing the heat generated when syngas forms.



Cost/bbl	
Capital	$2.25
O&M	$2.00
Total	$4.25

Syntroleum's N_2-diluted technology

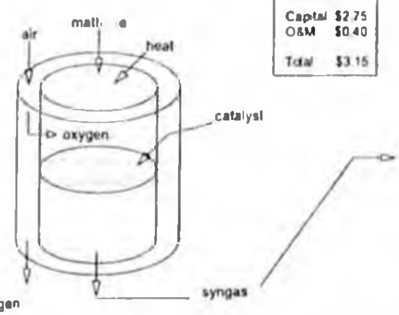
Syntroleum uses autothermal reforming with air instead of oxygen. The nitrogen by-product travels through the process.



Cost/bbl	
Capital	$2.00
O&M	$1.50
Total	$3.50

DOE's Ceramic Membrane technology

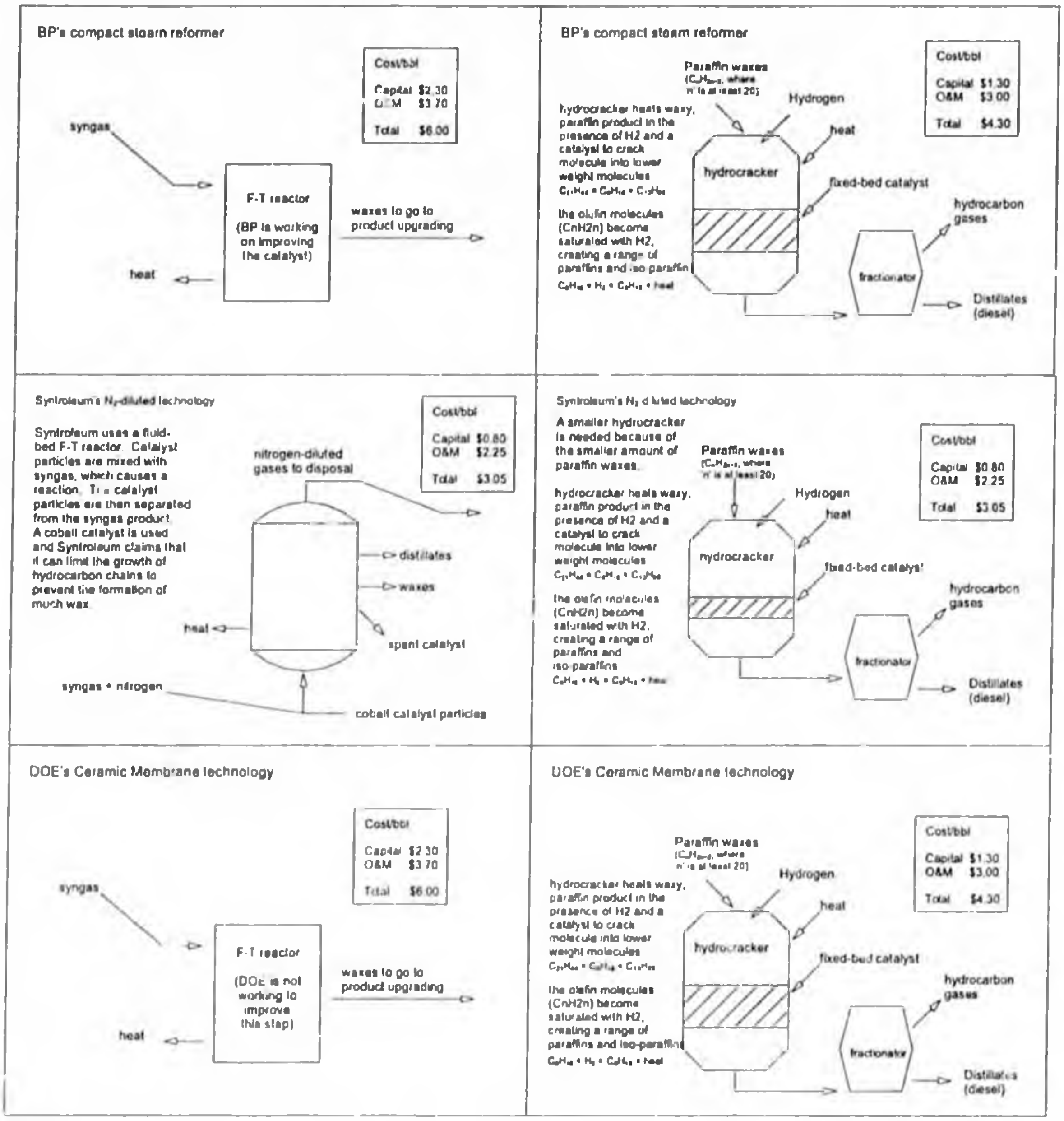
The oxygen in the air travels through the ceramic membrane to react with the methane to form syngas.



Cost/bbl	
Capital	$2.75
O&M	$0.40
Total	$3.15

Step Three: Fischer Tropsch synthesis

Step Four: Product upgrading



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