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Conversion Economics for Alaska North Slope Natural Gas

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2B.4 Conversion Economics for Alaska North Slope Natural Gas

CONTRACT INFORMATION

Contract Number	DE-AC07-94ID13223
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Period of Performance	January 01, 1995 to December 31, 1995

Schedule and Milestones

FY95/96 Program Schedule

	J	F	M	A	M	J	J	A	S	O	N	D	J
Summary/status - ANS oil and gas resources and fields	X	X	X										
Evaluate alternatives for moving ANS gas to market			X	X	X	X							
Economic requirements for ANS gas-to-liquids projects				X	X	X							
Effects of gas sales					X	X							
Interim report, industry/government review							X						
Revise study based on review								X					
Analysis of economic benefits and incentive effects									X	X			
Draft report/review/final report									X	X	X		

OBJECTIVES

The purpose of this project is to perform an economic and technical feasibility study of the alternatives for bringing Alaska North Slope (ANS) natural gas resources to market. The economic requirements for gas-to-liquids conversion processes to be viable on the North Slope and the effects such processes would have on the development and utilization of the natural gas resources will be determined and compared to scenarios involving natural gas pipelines, LNG plants, or both. The objectives of the study are as follows:

(a) Review and summarize the ANS oil and gas resources and the status of currently producing fields and known undeveloped fields.

(b) Evaluate alternatives for moving ANS natural gas to market; i.e.. gas pipeline/liquified natural gas (LNG) plant scenarios, and gas-to-liquids conversion technologies that result in hydrocarbon liquids for transport in the Trans-Alaska Pipeline System (TAPS).

(c) Determine the economic requirements for gas-to-liquids conversion processes to be viable on the North Slope.

(d) Evaluate the effects of major gas sales on current and future ANS oil and gas development and production, and on the life of TAPS.

(e) Estimate the effects of major ANS gas sales on industry, state of Alaska, and federal income.

(f) Evaluate the impact alternative taxation and production enhancement incentives could have on development of gas sales capabilities.

BACKGROUND INFORMATION

The natural gas resources in the developed and known undeveloped fields on the Alaskan North Slope total over 30 trillion cubic feet (Tcf).[1] Undiscovered gas resources on the ANS are estimated to be between 69 and 89 Tcf.[2] **Figure 1** is a map showing the location of the producing and nonproducing units and illustrates the significance of the infrastructure that has developed because of the Prudhoe Bay field. Most, if not all, of the smaller fields would not have been developed without facility cost-sharing made possible by this existing infrastructure, including TAPS. **Table 1** gives the remaining oil reserves and gas resources on the North Slope from the Alaska Department of Natural Resources, Division of Oil and Gas.

Currently, North Slope gas is not marketed off the North Slope except for natural gas liquids (NGLs), which are blended with crude oil for transport in TAPS. Historically and currently, the only market for North Slope gas is as a fuel for oil production facilities and related oil field activities. North Slope gas that is produced is injected back into the reservoirs and will be available for sale when a gas market is developed that will support construction of a gas pipeline system, or technology is developed that can economically convert the natural gas to hydrocarbon liquids that can be transported in TAPS.

Table 1. Estimated Remaining Reserves[a]

	Oil[b]	Gas[c]
North Slope Developed		
East Barrow	-	6
Endicott	226	894
Kuparuk River	1,318	682
Kuparuk Other	173	-
Lisburne	81	277
Milne Point	188	13
Niakuk/Alapah	61	33
Point McIntyre	405	300
Prudhoe Bay	3,432	26,000
Prudhoe Bay Other	7	7
South Barrow	-	4
Walakpa	-	28
Undeveloped		
North Star/Seal Island	180	-
Pt. Thomson/Flaxman Island	200	3,000
Total	6,271	31,244

a. From the Alaska Department of Natural Resources (Ref. 1)
b. Millions of barrels
c. Billions of cubic feet

North Slope fields had produced 10.3 billion barrels of oil by the end of 1994, 84% from Prudhoe Bay, 11% from Kuparuk, and 4% from the combined other pools (Reference 1). The ANS historical and projected production for currently producing fields is shown in **Figure 2**. ANS production has accounted for almost 25% of the nations domestically produced oil since production was initiated from the Prudhoe Bay field in 1977. The projected production in **Figure 2** is a composite of individual forecasts developed based on publicly available information obtained from North Slope producers, the Alaska Department of Natural Resources (Oil and Gas Conservation Commission and Division of Oil and Gas), and previous studies performed for the U.S. Department of Energy by the Idaho National Engineering Laboratory (INEL).[3,4] The arrows in **Figure 2** illustrate the potential impact a shutdown of TAPS, resulting from reaching a minimum throughput rate, would have on

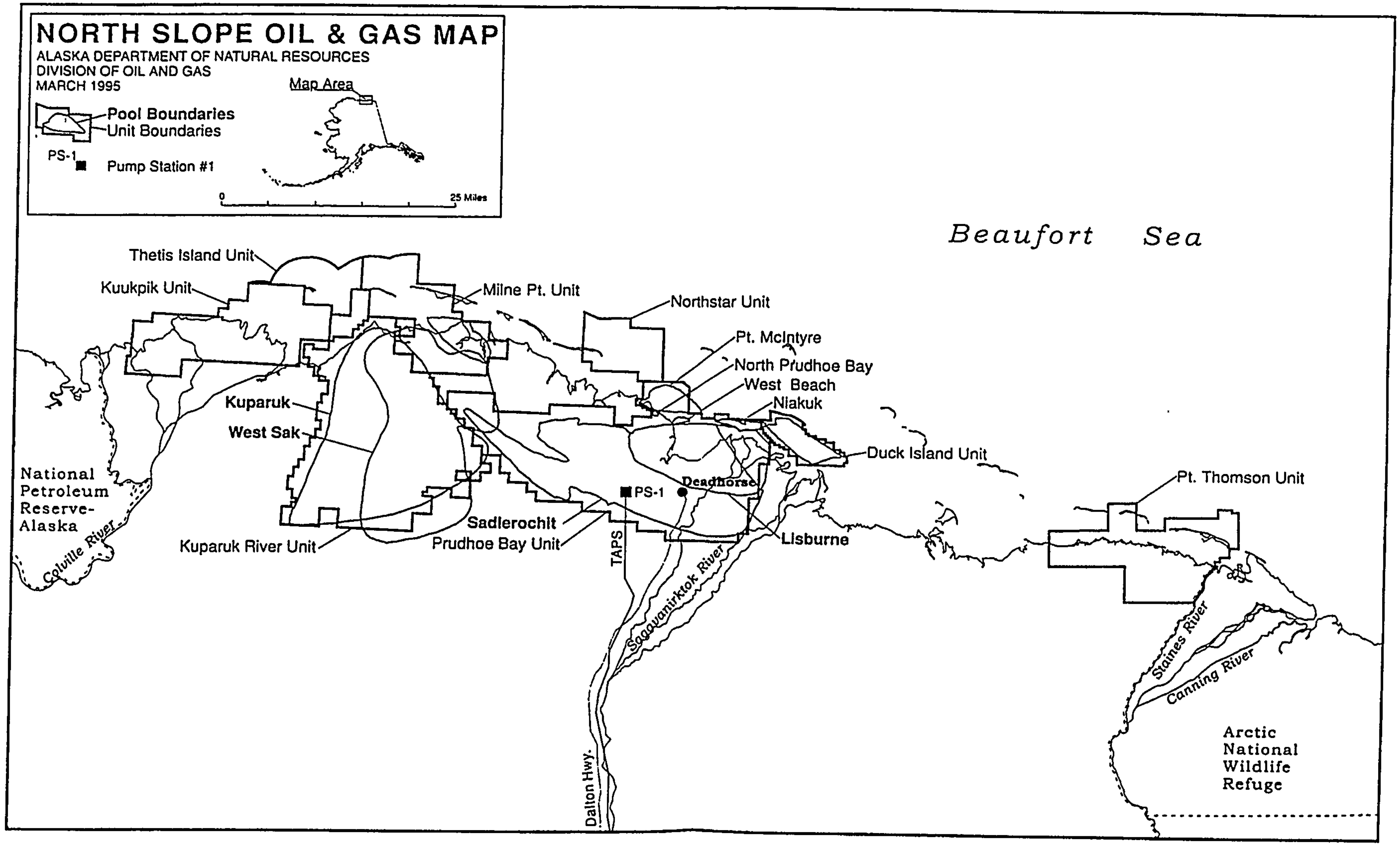

Figure 1. North Slope Alaska Oil and Gas Map

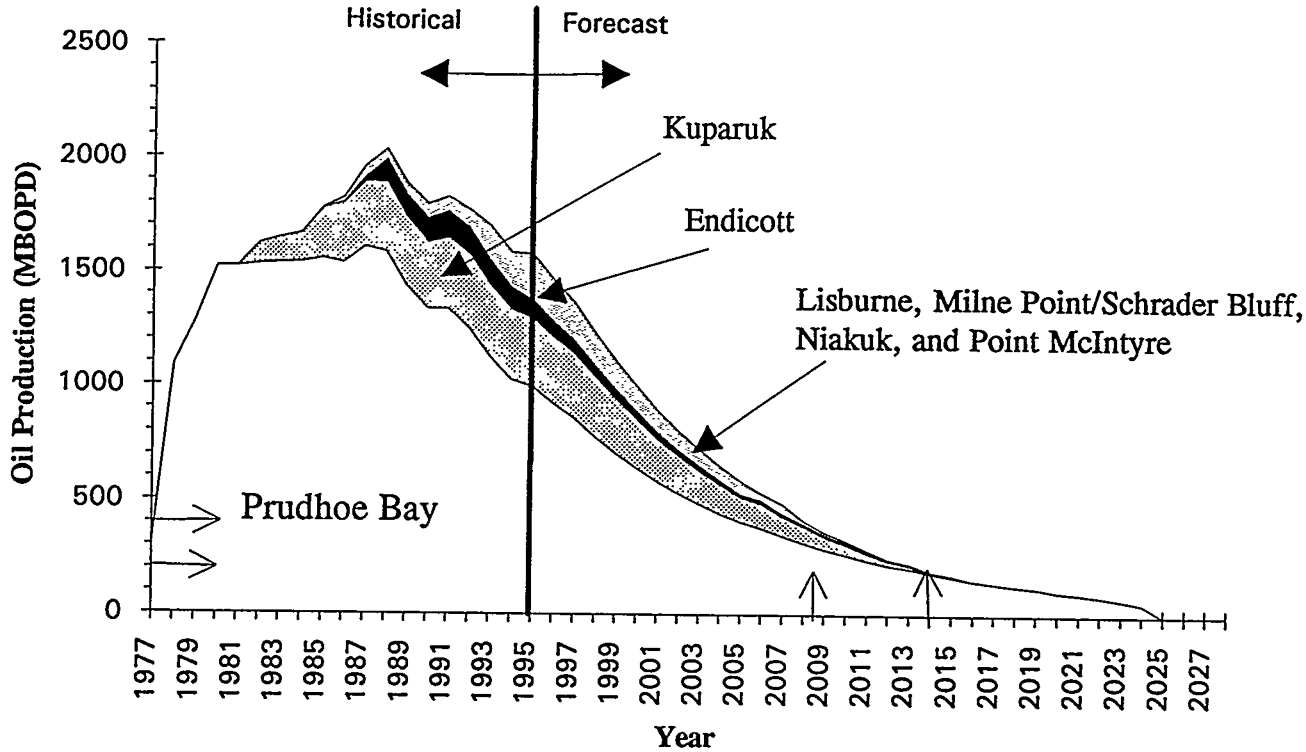

Figure 2. Historical and projected production for Alaska North Slope

the production of oil reserves from the North Slope. The actual lower limit for sustained operation has not been determined but would result from technical and economic considerations. A reasonable lower limit has been estimated to range from 400 to 200 thousand barrels per day (MBPD), which corresponds to a time range of 2009 to 2014 unless significant additional production becomes available. A shutdown at 2009 would result in a loss of reserves of about 1 billion barrels (BBO) and a shutdown in 2014 would result in a loss of about 400 million barrels (MMBO).

Since the discovery of the Prudhoe Bay field in 1968, numerous plans and ideas have been proposed for developing markets and a transportation system for North Slope gas. Prudhoe Bay contained 46 Tcf of gas and 23 billion barrels of oil at discovery. The most talked about proposal is the Trans-Alaska Gas System (TAGS), a $14 billion system consisting of a gas-conditioning plant on the North Slope; a 800-mile, 42-inch pipeline; an LNG plant/marine terminal at Valdez; and a LNG tanker fleet. LNG will be transported to Japan and other Pacific Rim countries. Yukon Pacific Corporation (YPC) has secured or satisfied all necessary legal approvals, requirements, and permits for construction of TAGS and export of ANS natural gas to Asia.[5] Construction of the project depends on obtaining long-term sales and purchase contracts with the North Slope owners of the gas supply and the LNG buyers in Asia. YPC believes the large scale of the project, 14 million metric tons of LNG annually, creates economies of scale that will allow this gas to be competitive with LNG projects closer to the Asian markets (Reference 5).

Another project that has been considered is the Alaskan Natural Gas Transportation System (ANGTS), which would involve a 4,783-mile pipeline through

Alaska and Canada to markets in the Lower 48 states. It appears unlikely that this project will be pursued any time in the near future.

Although large LNG markets exist in Pacific Rim countries (a) potential competition from overseas projects (e.g., Qatar, Natuna, and Sakhalin), (b) the large investments required for the TAGS pipeline, and (c) technical and economic factors relating to the best timing for initiation of major gas sales from the Prudhoe Bay Unit (PBU) have kept TAGS from being developed to date.

Except for the gas used for fuel for oil production, the gas that has been produced from the PBU has been reinjected into the reservoir to maintaining reservoir pressure, recycled into the gas cap to strip liquids, and used in a water-alternating-gas enhanced oil recovery project. Major gas sales from the Prudhoe Bay field will have an influence on the oil recovery from the field and could result in a reduction in the total oil recovery achieved depending on the timing and rate of gas sales. The reduction in oil recovery could vary from about 900 MMBO for major gas sales starting as early as 2000, to 400 MMBO for a 2005 start, to no effect for 2015 start.[6] The PBU owners are currently studying the issues and options involved with major gas sales and reviewing the options for reducing the influence on oil recovery.

The other known major gas field on the ANS is the Point Thomson field (see **Figure 1**). The Point Thomson Unit (PTU) covers a gas condensate field about 50 miles east of TAPS Pump Station No. 1. The PTU is listed in the most recent estimates by the Alaska Department of Natural Resources, Division of Oil and Gas (Reference 1) as containing 200 MMB of condensate and 3 Tcf of gas (earlier estimates were 300 MMB condensate and 5 Tcf gas). The PTU currently covers about 83,800 acres and is a deep overpressured reservoir that is located mostly offshore (see **Figure 1** and Reference 4). Development of the Point Thomson field is hindered by the lack of existing infrastructure and facilities that benefit fields in the vicinity of the Prudhoe Bay field. A Point Thomson development must support the construction of field delivery lines to the Prudhoe Bay field area that will encounter five major river crossings and cross the Arctic Coastal plain. The impact of these conditions will not be determined until environmental assessments are conducted.

In addition to the benefits in terms of profits for the industry, and taxes and royalties for the state of Alaska and the federal government from the sale of the gas on the ANS, the future of North Slope oil production beyond the 2009 to 2014 time frame depends on maintaining the viability of TAPS to support future development of known and undiscovered fields. The continued viability of the existing ANS oil and gas production infrastructure and operation of TAPS through discovery and development of new and known undeveloped oil fields will have a very important impact on the U.S. domestic oil supply. Economically viable processes to convert gas to hydrocarbon liquids that can be transported in TAPS could also have a significant impact on the future of the ANS.

Additionally, the ANS has an estimated 40 billion barrels of heavy oil and bitumen in the shallow formations of the West Sak and Ugnu fields (**Figure 1**).[7] The exploitation of these resources depends on maintaining the viability of TAPS until these resources can be economically developed. In addition to the impact of gas-to-liquids processes on the future of the ANS, economic processes for upgrading of heavy oils and tars in remote locations could also have a significant impact.

PROJECT DESCRIPTION

The economic model developed for the previous North Slope studies performed by the INEL will be updated as needed and used to evaluate the economics of the alternatives for ANS gas sales and the effects of the alternatives on future development and production. The model has been described in detail in References 3 and 4.

The project approach will include the following steps:

(a) The current status of oil and gas resource development will be evaluated. Production, investment, and operating cost forecasts will be developed for the producing and undeveloped fields that have significance for this study; e.g., the Point Thomson gas condensate field.

(b) Economic evaluations for each field will provide a baseline for current oil reserves using several oil price scenarios and allow a determination of the impact of gas sales scenarios on future oil production.

(c) The Prudhoe Bay field will be evaluated first. Prudhoe Bay without major gas sales, will provide the basis for evaluation of the effects of major gas sales through development of TAGS, or a similar project. A range of producer's gas price net-back values will be used to evaluate the project. The gas net back will be based on Pacific Rim LNG prices tied to the price of crude oil on the world market. Sensitivities of the economics of continued operations and new developments to the net back values for the gas sales will be determined.

(d) Requirements for capital costs, operating costs, and process efficiency for gas-to-liquids conversion processes to be economically viable for Prudhoe Bay, Point Thomson, and other gas resources will be determined for specific field development scenarios. The relative influence of capital costs for power and conversion plants, conversion efficiencies, operating costs, and product value will be determined using estimated costs for existing and emerging gas-to-liquids processes.

(f) The results of the gas-to-liquids conversion requirements will be compared to gas pipeline/LNG sales scenarios.

(g) The feasibility evaluation of gas conversion processes will include the overall impact such processes could have on North Slope production from extended life of the developed fields and development of additional fields.

(h) The impact that alternative taxation and production enhancement incentives could have on economic feasibility will be evaluated. For example, the severance tax calculation for gas could be based on total gas delivered to the conversion plant or an alternative method based on the produced liquid.

RESULTS

The results presented in this paper are preliminary; the data gathering phase of the project was initiated on March 6, 1995. The production forecasts and the economic evaluations are subject to change and should not be quoted or used without consultation with the authors.

The production forecasts, investment forecasts, and operating costs have been updated for Prudhoe Bay, Kuparuk River, Endicott (Duck Island Unit), Lisburne, Milne Point (includes Schrader Bluff), Niakuk, and Point McIntyre. The historical and projected production from these fields is shown in **Figure 2**.

The economic model and the methodology used for the evaluations has been previously described in References 3 and 4. A discount rate of 10%, an inflation rate of 2.2%, and the World Oil Price cases shown in **Figure 3** have been used for the preliminary analyses presented in this paper. The discount rate that industry would use as a hurdle rate to make investment decisions could be much higher than the 10% we have used in this analysis. The inflation rate and the World Oil Price cases are taken from the Energy Information Administration's (EIA) *Annual Energy Outlook 1995*.[8] The World Oil Price cases consist of the reference case and low and high price cases to reflect the uncertainty in world oil markets. The curves in **Figure 3** are in 1995 dollars.

Preliminary results have been obtained for major gas sales from the Prudhoe Bay field for a gas pipeline/LNG plant project, such as TAGS, where the producers receive a gas price at the wellhead based on a gas net-back fraction, and gas-to-liquids conversion plants with assumed input parameters for capital and operating costs and efficiencies.

An evaluation of the economic viability of the TAGS system is not within the scope of this project. It is assumed for the purposes of this work that, if the project is built, it will be able to pay the producers for the gas at the rates assumed. Sensitivities to the producers' gas net-back fraction will be included in the analyses. This case is compared to a hypothetical gas-

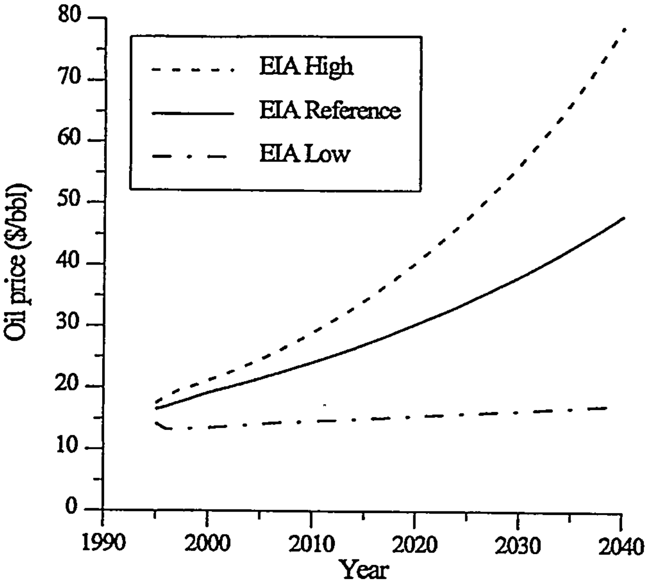

Figure 3. World Crude Oil Prices (1995 dollars)[8]

to-liquids conversion plant located in the Prudhoe Bay field and operated by the PBU Owners. Present Worth using a 10% discount rate (PW_{10}) is used to compare projects, (present worth is the cumulative after tax cash flow discounted to current year dollars; i.e., 1/1/95 for this study).

Prudhoe Bay - No Major Gas Sales

The base case for the Prudhoe Bay field uses the production forecast shown in **Figure 2**, the EIA Reference crude oil price case (**Figure 3**), a TAPS tariff schedule developed for the projected production from the ANS, transportation costs from Valdez to Lower 48 ports (California or Gulf Coast), a quality differential for North Slope crude of -$1.00 (applied to account for the estimated lower value of ANS crude relative to the world oil price), estimated future investments and operating costs, state taxes and royalties, and federal taxes. The wellhead oil price is obtained by subtracting the TAPS tariff, transportation costs, and quality differential from the world oil price. The EIA Reference oil price case with these input parameters results in total economic production from the Prudhoe Bay field of 12.75 BBO or 55.5% of the Original Oil in Place (OOIP). With these input parameters, the field would become uneconomic in 2022. The PW_{10} is $6.5 billion for this case. The present worth at the 10% discount rate (PW_{10}) is $11.3 billion for the state of Alaska (severance tax, conservation tax, conservation surtax, ad valorem, income tax, and royalty) and $2.4 billion for the federal government. Early shutdown of TAPS resulting from total ANS production reaching a shutdown limit would reduce this recovery by as much a 400 to 800 MMBO from Prudhoe Bay alone.

Prudhoe Bay - Major Gas Sales

The natural gas available from the Prudhoe Bay field is estimated as follows (starting with the original gas in place (OGIP) in the gas cap and oil rim):

Gas Cap = 30 Tcf (OGIP) x 0.80	=	24.0 Tcf
Oil Rim = 16 Tcf (OGIP) x 0.60	=	9.6 Tcf
Total Recoverable Gas	=	33.6 Tcf
Less CO_2 @ 12% = 33.6 Tcf x 0.88	=	29.6 Tcf
Less Fuel:		
Fuel used through 1994	=	1.9 Tcf
Estimated Future use	=	5.4 Tcf
Total Fuel Use	=	7.3 Tcf
Estimated Net After Fuel	=	22.3 Tcf
Less Estimated Liquids Shrinkage	=	1.5 Tcf
Net For Delivery to Pipeline	=	**20.8 Tcf**

Three scenarios have been evaluated to illustrate the relative impact and potential of major gas sales, (a) a pipeline/LNG plant scenario, and (b) two gas-to-liquids projects producing pipeline compatible hydrocarbon liquids.

Gas Pipeline/LNG Plant. The economic impact of a gas pipeline/LNG system for major gas sales from the Prudhoe Bay field has been evaluated through the use of a producers gas net-back fraction based on estimated LNG prices in the Asian market (e.g., Japan, Taiwan, S. Korea).

The producer's gas net-back price at the wellhead is the LNG price times a producer's gas net-back fraction; e.g., 15%.

$$\text{LNG Price} = \frac{\text{World Oil Price x LNG Parity}}{\text{BTU Conversion}}$$

where,

World Oil Price = Ref. Oil Price (**Figure 3**)

LNG Parity = 1.1

$$\text{BTU Conversion} = \frac{\text{Million (MM) BTU/BBL Oil}}{\text{MM BTU/Mcf gas}}$$

$$= \frac{\text{6.25 MM BTU/BBL oil}}{\text{1.059 MM BTU/Mcf gas}}$$

BTU Conversion = 5.9 Mcf/BBL.

The resulting producer's gas net-back price is \$0.47/Mcf in 1995 for a gas net-back fraction of 15% for the EIA Reference oil price of \$15.67/BBL (1995 dollars). Gas sales are ramped up over a 5-year period to a maximum of 2.4 Bcf/day (i.e., 0.5, 1.0, 1.5, 2.0, 2.4 Bcf/day). The gas available for delivery as LNG to the Asian market, after transportation fuel and losses, is 2.0 Bcf/day, or 14 million metric tons per year for 20 years.

The effect on total oil recovery resulting from less gas being available for pressure maintenance, recycling, and miscible injectant for enhanced oil recovery caused by major gas sales starting in 2005 is estimated to be 400 million barrels of oil. The production forecasts with this reduction in oil reserves and major gas sales are shown in **Figure 4**. The resulting PW_{10} for this case at a 15% gas net back is \$8.1 billion. The PW_{10} for the state is \$11.5 billion and \$3.3 billion for the federal government.

Gas-To-Liquids Conversion. For the gas-to-liquids cases, nominal values and costs have been assumed without reference to a particular technology for illustrative purposes. These assumptions will be verified for specific processes in the future work on this project and are presented here as an example of the potential and impact of such processes for application at Prudhoe Bay.

Two cases, a 300,000 barrel per day (BPD) plant and a 200,000 BPD plant, with start up in 2005, and a ramp up of 5 years, have been considered. The lost oil reserves are assumed to be 400 MMBO, the same as for the gas pipeline/LNG plant case. A capital cost of \$40,000 per barrel per day (BPD) of hydrocarbon liquid produced is used for both cases. On the North Slope, a power plant and a conversion plant would have to be constructed and both are included in the \$40,000/BPD value used for the calculations. One-third of the input gas is used for power plant fuel, and the gas to hydrocarbon liquid conversion efficiency is assumed to be 75%. The value of the product is expected to be of higher value than North Slope crude and is given a \$5 per barrel premium; e.g., gasoline or aviation fuel grade. The TAPS tariff varies with the throughput rate; i.e., increased flow reduces the tariff rates. Therefore, a different tariff schedule is required for each case. Severance taxes have been calculated on the gross gas produced rather than on the product sold and valued based on the product sale value.

For the 300,000 BPD plant, the production forecast is shown in **Figure 5**. The plant cost at \$40,000/BPD is \$12 billion. A gas production rate of 3.6 Bcf/day, removal of 12% CO_2, use of 1.2 Bcf/day for fuel, a conversion efficiency of 75%, and a BTU conversion of 5.3 Mcf/BBL results in 300,000 BPD of hydrocarbon liquids. The PW_{10} for this case is \$8.2 billion. The PW_{10} for the state of Alaska is \$13.8 billion and \$3.8 billion for the federal government. The resulting benefit to continued operation of TAPS, assuming a 200 MBOPD lower limit, is 8 years, 2022 versus 2014, and would result in production of almost 2 billion barrels of additional petroleum liquids from the gas conversion. Impact on total ANS production will be determined later in the project.

For the 200,000 BPD gas-to-liquids case (see **Figure 5**), the plant cost at \$40,000/BPD is \$8 billion. The required gas rate is 2.4 Bcf/day for this case with the same fuel requirements and conversion efficiency. The PW_{10} for this case is \$8.7 billion. The PW_{10} for the state of Alaska is \$13.2 billion and \$3.9 billion for the federal government. The project is extended until

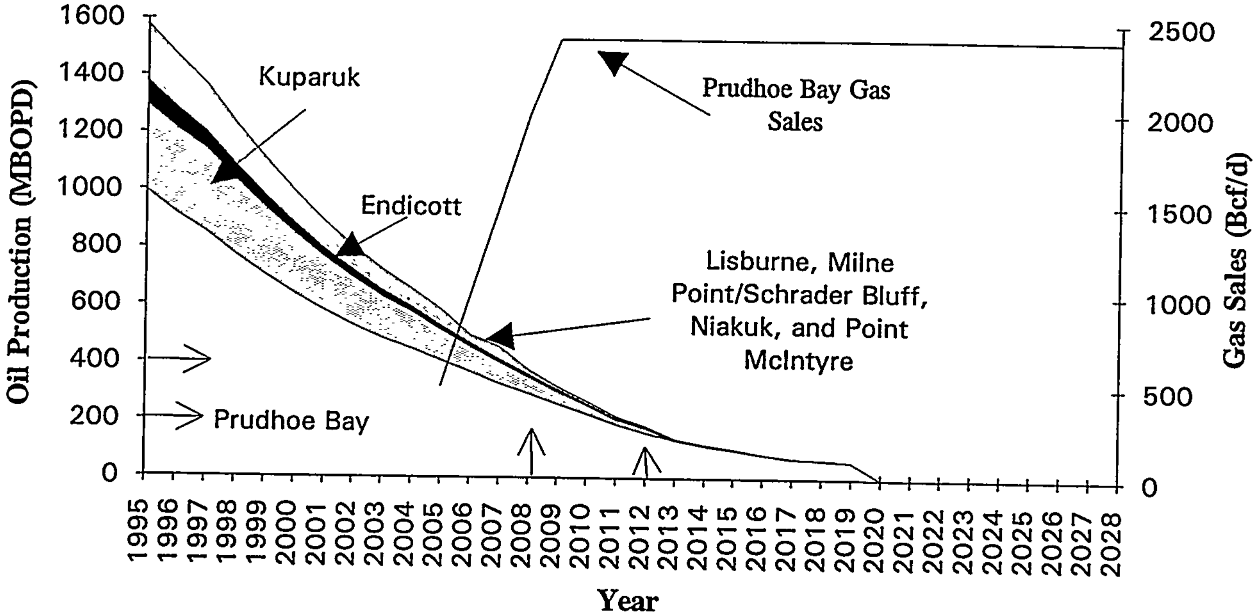

Figure 4. Prudhoe Bay field production forecast w/major gas sales

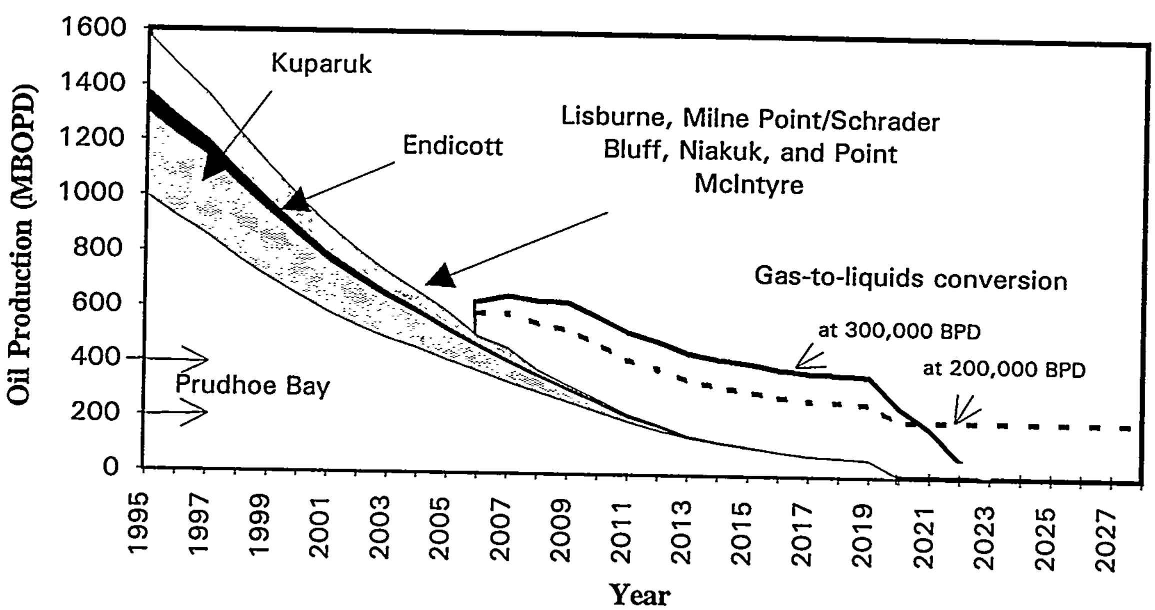

Figure 5. Prudhoe Bay field w/gas-to-liquid conversion

2028 using the lower limit for TAPS of 200 MBOPD for an additional 14 years of production compared to the base case. The total oil and hydrocarbon liquid increase is the same as above considering only the Prudhoe Bay field.

Summary

For the Prudhoe Bay field, this preliminary analysis provides an indication that major gas sales using a gas pipeline/LNG plant scenario, such as TAGS, or a gas-to-liquids process with the cost parameters assumed, are essentially equivalent and would be viable and profitable to industry and beneficial to the state of Alaska and the federal government. The cases are compared in **Table 2** ($1995 dollars, billions) for the Reference oil price case. The reserves would be 12.7 BBO for the base case without major gas sales, 12.3 BBO and 20 Tcf gas for the major gas sales case, and 14.3 BBO for the gas-to-liquids conversion cases.

Table 2. Preliminary Economics for Natural Gas Sales and Conversion for the Prudhoe Bay Field

Project	Life	PW_{10}	State	Federal
No Major Gas Sales	2022	$6.5	$11.3	$2.4
Major Gas Sales	2028	$8.1	$11.5	$3.3
300 MBPD	2022	$8.2	$13.8	$3.8
200 MBPD	2028	$8.7	$13.2	$3.9

Use of different parameters such will significantly alter these results; e.g., the low oil price case would result in the base case for Prudhoe Bay field becoming uneconomic in 2002 with the operating costs and investments as currently estimated.

FUTURE WORK

Work was initiated for this project on March 6, 1995 and all the results presented are preliminary and will be reviewed for errors in the input data and assumptions before reaching conclusions about any of the projects.

Future work will include checking the data used, obtaining confirmation of values for the costs and conversion efficiencies associated with specific gas-to-liquids conversion technologies (to the extent such information is known and available); extending the analysis to other fields on the North Slope, particularly the Point Thomson gas field; and reviewing the impact of the alternatives on the future of North Slope development and production.

Sensitivity analysis will be used to determine the effect of the variables such as low and high oil price forecasts, gas net-back fraction, capital costs for power plant and conversion plant construction, gas required to operate the power plant for different gas-to-liquids technologies, timing of project start up, taxation rates and methodologies, value of hydrocarbon product and effect of product type on operation of TAPS.

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