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ASSESSMENT OF COSTS AND BENEFITS OF FLEXIBLE AND ALTERNATIVE FUEL USE IN THE U.S. TRANSPORTATION SECTOR

TECHNICAL REPORT TWELVE:

ECONOMIC ANALYSIS OF ALTERNATIVE USES FOR ALASKAN NORTH SLOPE NATURAL GAS

December 1993

United States Department of Energy
Office of Policy, Planning, and Program Evaluation

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EXECUTIVE SUMMARY

As part of the Alternative Fuels Assessment, the Department of Energy (DOE) is studying the use of derivatives of natural gas, including compressed natural gas and methanol, as alternative transportation fuels. A critical part of this effort is determining potential sources of natural gas and the economics of those sources.

Previous studies in this series characterized the economics of unutilized gas within the lower 48 United States, comparing its value for methanol production against its value as a pipelined fuel (U.S. Department of Energy 1991), and analyzed the costs of developing undeveloped nonassociated gas reserves in several countries (U.S. Department of Energy 1992c). This report extends those analyses to include Alaskan North Slope natural gas that either is not being produced or is being reinjected. The report includes the following:

- A description of discovered and potential (undiscovered) quantities of natural gas on the Alaskan North Slope.
- A discussion of proposed alternative uses for Alaskan North Slope natural gas.
- A comparison of the economics of the proposed alternative uses for Alaskan North Slope natural gas.

The purpose of this report is to illustrate the costs of transporting Alaskan North Slope gas to markets in the lower 48 States as pipeline gas, liquefied natural gas (LNG), or methanol. It is not intended to recommend one alternative over another or to evaluate the relative economics or timing of using North Slope gas in new tertiary oil recovery projects. The information is supplied in sufficient detail to allow incorporation of relevant economic relationships (for example, wellhead gas prices and transportation costs) into the Alternative Fuels Trade Model, the analytical framework DOE is using to evaluate various policy options.

Available Resources

As of January 1, 1990, about 33 trillion cubic feet (tcf) of geologically proved reserves had been identified in Alaskan North Slope fields, most of which are associated with the Prudhoe Bay oil reservoirs.The only major discovered nonassociated gas field is Point Thompson, with reserves estimated at 5 tcf.

Although estimates of reserves for known discoveries in Alaska are fairly reliable, especially for the Prudhoe Bay field, most of the gas reserves are not booked as economically recoverable because of the lack of a way to transport the gas to the marketplace and the high cost of constructing such a system. At the beginning of 1990, only 9 tcf of Alaskan natural gas were classified as proved reserves. Booked wet gas reserves for the lower 48 States were 166 tcf at the beginning of 1992 (U.S. Department of Energy 1992a).

Estimates of undiscovered gas resources beneath the Alaskan North Slope and the Beaufort and Chukchi Seas range from about 69 tcf to 89 tcf.

Nonconventional gas resources in northern Alaska may eventually be produced from coalbed methane and gas hydrate formations. Coalbed methane resource estimates range from 14 tcf to 95 tcf. Gas hydrate resource estimates range from 8 tcf to hundreds of tcf. The geological characteristics and economics of these nonconventional gas resources are highly uncertain; neither is expected to play a role in the foreseeable future.

Economic Factors

The vast majority of the discovered gas on the Alaskan North Slope is associated-dissolved gas that is being reinjected for pressure maintenance and miscible flooding (a form of tertiary oil recovery). It is expected that these uses will continue until approximately 2010. Thus, this report examines the economics of the following alternatives for using Alaskan North Slope gas in 2010 or the years beyond:

- Pipeline gas sales to the lower 48 States.
- Conversion to LNG for sale in Japan or California.
- Conversion to fuel-grade methanol for sale in Japan or California.

Determining the economics of a fourth alternative, using the gas in other enhanced oil recovery (EOR) projects, was beyond the scope of this study.

To arrive at a common value for comparison of the alternatives examined, production and transportation costs were subtracted from the end-use value of the gas product to arrive at a wellhead value for the gas on the North Slope.

The economics of the following specific options were considered in this study:

- Pipeline sale of gas to the lower 48 States via the proposed Alaska Natural Gas Transportation System (ANGTS).
- Pipeline sale of gas to the lower 48 States via a northern Alaska connection with the proposed Mackenzie Valley pipeline.
- Transport of gas to Valdez via pipeline, liquefaction at Valdez, and shipment to Japan as LNG.
- Transport of gas to Valdez via pipeline, liquefaction at Valdez, and shipment to California (Los Angeles) as LNG.
- Transport of gas to Valdez via pipeline, conversion to methanol at Valdez, and shipment to Japan as methanol.
- Transport of gas to Valdez via pipeline, conversion to methanol at Valdez, and shipment to California (Los Angeles) as methanol.

To achieve a wellhead value of $0.50 per thousand cubic feet (Mcf), gas produced on the North Slope and transported to the lower 48 States via ANGTS would only be competitive with a lower 48 U.S. wellhead price of about $4.29 per Mcf.[1] This is based on the estimated levelized cost of service for ANGTS during its first 10 years of operation. The before-tax real target rate of return for the pipeline is assumed to be 10.5 percent.

Similar evaluations have been made for pipeline sales via a northern link with the Mackenzie Valley pipeline. Because of its lower estimated costs, this alternate route yields a theoretical competitive price of $3.48 per Mcf in the lower 48 States if the gas is valued at $0.50 per Mcf on the North Slope.

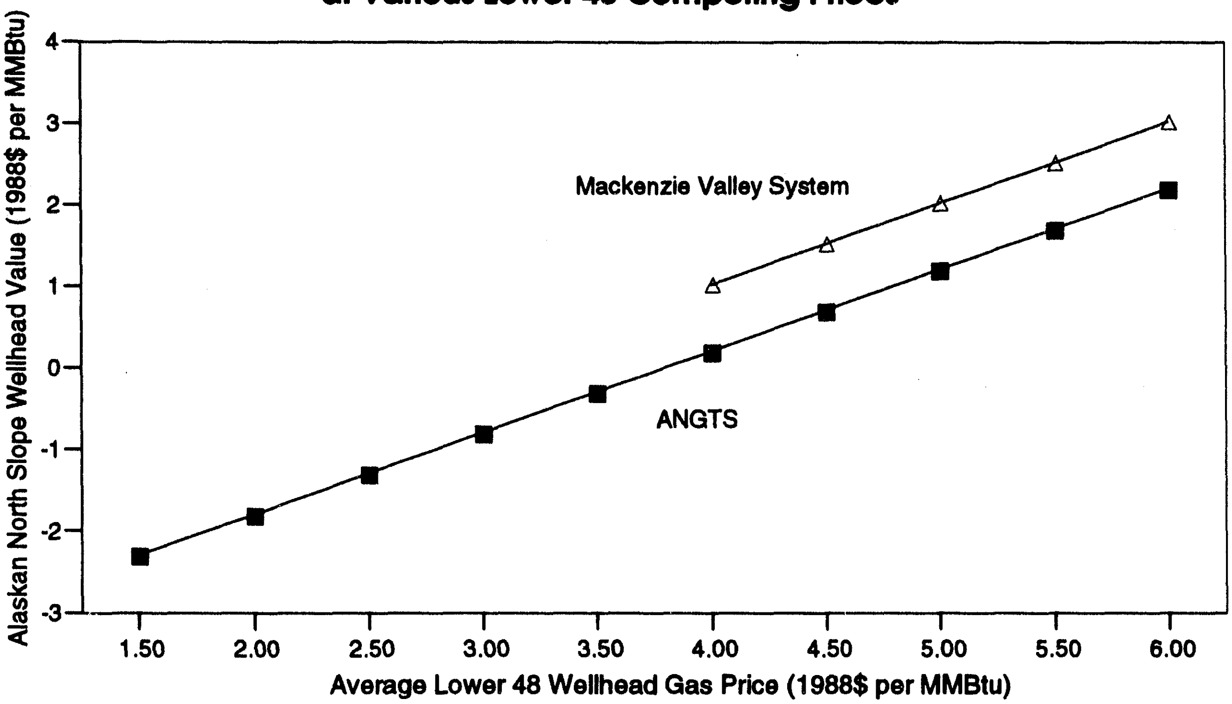
The Mackenzie Valley route requires construction of a pipeline to carry Canadian gas from the Mackenzie River Delta area to Caroline, Alberta. Applications to the National Energy Board of Canada (NEB) for construction of a pipeline from the Mackenzie Delta indicate that transportation costs to the U.S. border will be approximately $3.00 per Mcf. Applications to the NEB by the producers for gas export licenses indicate that gas production costs will average approximately $1.00 per Mcf. Thus, construction of the Mackenzie Valley pipeline will not be economic until the average U.S. wellhead price exceeds $4.00 per Mcf. The true threshold price for the Mackenzie Valley route for Alaskan North Slope gas is not much different from that of ANGTS (National Energy Board of Canada 1989a; National Energy Board of Canada 1989c).

Figure S–1 depicts the North Slope wellhead value for the pipeline options at various lower 48 competing prices. Note that the Mackenzie Valley option begins at a lower 43 average wellhead price of $4.00 per Mcf.

LNG sales were brought back to a wellhead value in a similar manner; that is, the costs of pipeline transport to Valdez, liquefaction, LNG tanker transport, and regasification were subtracted from potential revenue. The pipeline, liquefaction plant, and regasification plant components of an LNG project were translated to a unit cost based on a real rate of return of 10 percent over 15 years. LNG shipping expenses were costed in a similar manner, but with a real rate of return of 4.8 percent because of an assumed greater debt portion of tanker financing. To achieve a netback wellhead revenue of $0.50 per Mcf, North Slope gas sold as LNG in Japan needs to receive about $4.75 per Mcf (1988 dollars) after regasification. LNG sold in California needs to

[1] All cost estimates in this report are stated in 1988 U.S. dollars unless otherwise specified.

Figure S–1 — North Slope Wellhead Value for Pipeline Options at Various Lower 48 Competing Prices



receive about $4.40 per Mcf (1988 dollars) after regasification. Figure S–2 depicts the North Slope wellhead value for the LNG options at various prices.

Methanol must compete with gasoline at an equivalent retail price on a British thermal unit (Btu) basis. Given that a gallon of methanol has approximately half the thermal energy of a gallon of gasoline and also has higher per-gallon storage and transportation costs, equal retail pricing per Btu translates into a wholesale plantgate value of methanol that is 22 to 28 percent of the retail price of gasoline. For example, a retail price of gasoline of $1.46 per gallon means that methanol blended for M85 (85 percent methanol, 15 percent gasoline) would have a plantgate wholesale value of 38.4 cents per gallon. The costs of pipeline transport to Valdez, conversion to methanol, and tanker transport were subtracted from potential revenue to arrive at the wellhead value. The pipeline and conversion plant components of a methanol project were translated to a unit cost based on a real rate of return of 10 percent over 15 years. Methanol shipping expenses are based on typical petroleum-product carrier rates. To achieve a wellhead value of $0.50 per Mcf, North Slope gas sold as methanol in Japan needs to receive about $0.395 per gallon. Methanol sold in California needs to receive about $0.385 per gallon. Figure S–3 depicts the North Slope wellhead value for the methanol options at various prices.

Economics in 2010 Under Energy Information Administration Scenarios

Table S–1 compares the approximate wellhead value in 2010 for gas or gas product sales for the options summarized in the previous section using product prices consistent with three oil price scenarios in the Energy Information Administration's (EIA) *Annual Energy Outlook 1992* (U.S. Department of Energy 1992a). Wellhead values are expressed as dollars per million Btu (MMBtu) of gas produced and take into account gas lost as fuel during conversion and transport. The column in Table S–1 labeled "Competing Fuel Price" is the forecast price of the most likely competition for Alaskan gas sold as pipeline gas, LNG, and methanol fuel. The "Total Processing and Delivery Cost" column represents the total cost of transportation, conversion to LNG or to methanol, and all fuel use associated with transportation and conversion.

Figure S-2 — North Slope Wellhead Value for Liquefied Natural Gas Options at Various Lower 48 Competing Prices

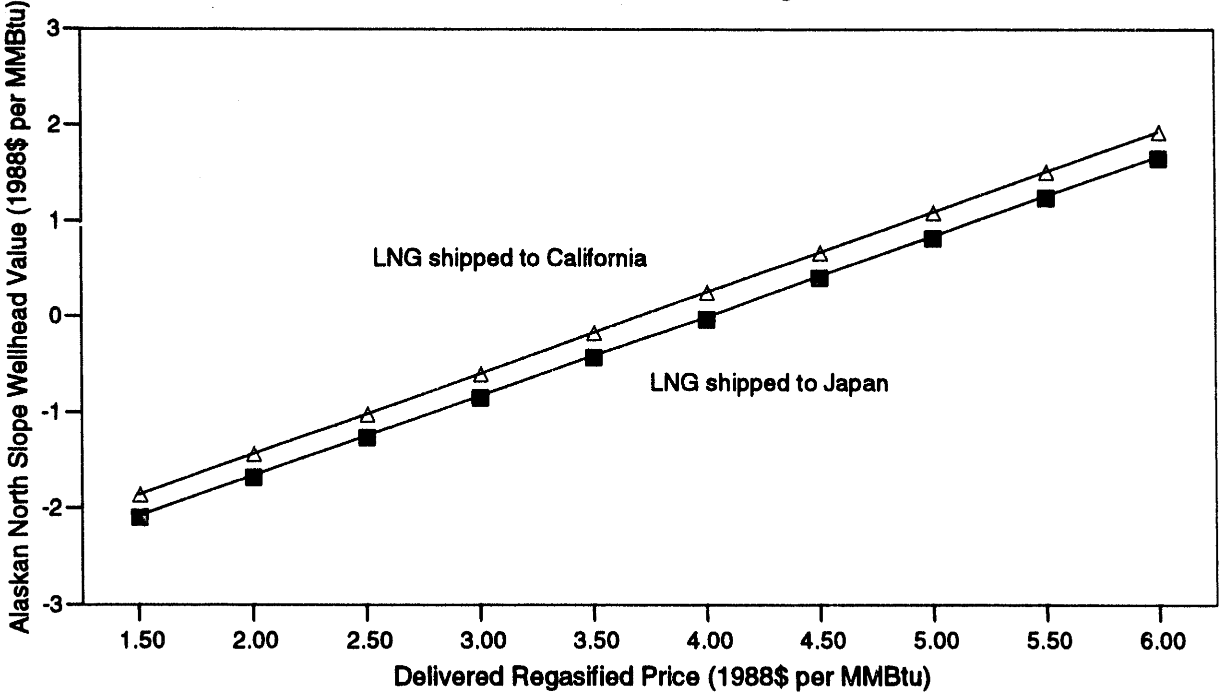


Figure S-3 — North Slope Wellhead Value for Methanol Options at Various Lower 48 Competing Prices

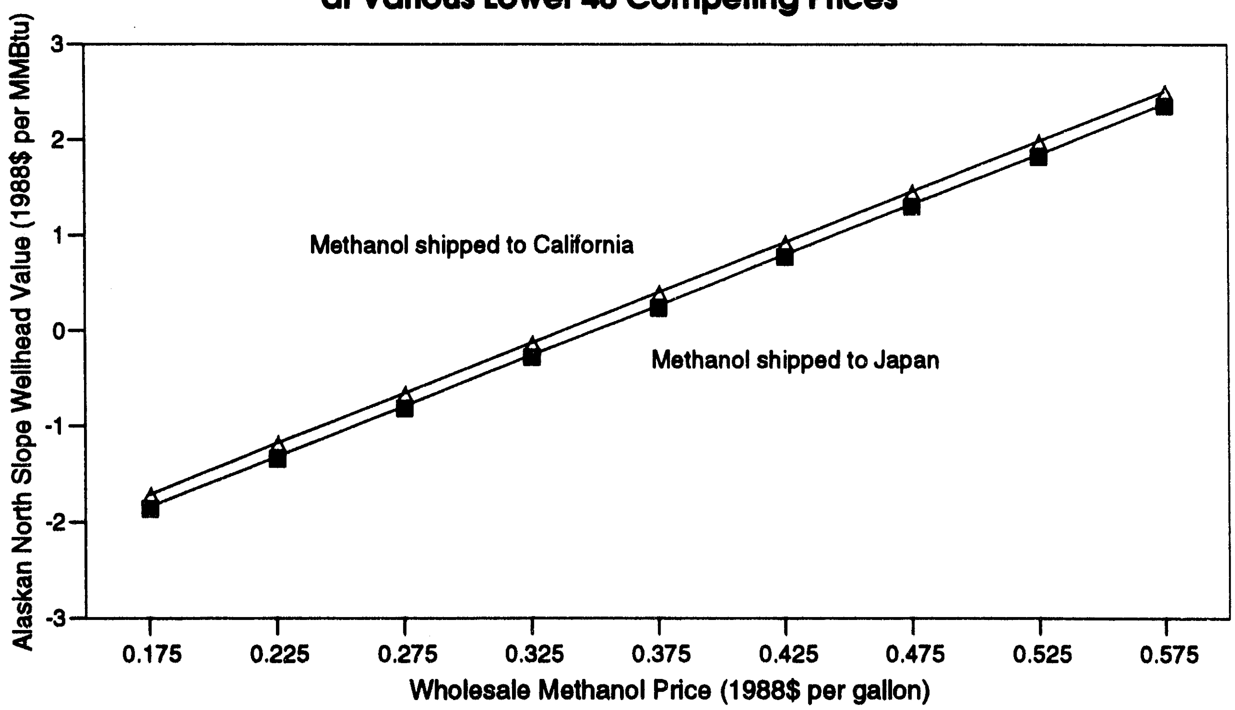


Table S-1 — Wellhead Value of Alaskan North Slope Gas in 2010

Option	Competing Fuel Price: EIA Low Oil Price Case	Competing Fuel Price: EIA Reference Case	Competing Fuel Price: EIA High Oil Price Case	Total Processing and Delivery Cost[a] (Low/Ref/High)	Alaskan North Slope Wellhead Netback Value: EIA Low Oil Price Case	Alaskan North Slope Wellhead Netback Value: EIA Reference Case	Alaskan North Slope Wellhead Netback Value: EIA High Oil Price Case
	(1988$/MMBtu)			(1988$/MMBtu)	(1988$/MMBtu)		
ANGTS Pipeline	3.58	4.16	4.00	3.79/3.79/3.79	(0.21)	0.37	0.21
Mackenzie Valley Pipeline[b]	3.58	4.16	4.00	2.98/2.98/2.98	NA	1.18	1.02
LNG to Japan[c]	3.66	5.05	5.75	3.94/4.17/4.28	(0.28)	0.88	1.47
LNG to California[d]	4.08	4.66	4.50	3.77/3.86/3.83	0.31	0.80	0.67
	(1988$/gallon)			(1988$/gallon gas equiv.)	(1988$/MMBtu)		
Methanol to Japan	0.261	0.384	0.454	3.76/3.78/3.80	(0.94)	0.36	1.10
Methanol to California	0.261	0.384	0.454	3.62/3.65/3.67	(0.80)	0.49	1.23

Note: All forecast prices adapted from EIA, *Annual Energy Outlook 1992*, June 1992, which includes the following scenarios:

	EIA Low Oil Price Case	EIA Reference Case	EIA High Oil Price Case
World Oil Price (1988$/bbl)	21.22	30.81	37.08
U.S. Average Wellhead Gas Price (1988$/MMBtu)	3.58	4.16	4.00
Estimated Methanol Value (1988$/gallon)	0.261	0.384	0.454

Conversion from 1988 dollars to 1990 dollars: 1.084

[a] Delivery costs will vary with price in the LNG and methanol options because of the large amount of gas consumed during conversion and transport.
[b] The Mackenzie Valley route for Alaskan gas requires that a pipeline for Canadian gas be built first. This is unlikely to happen until U.S. average wellhead prices exceed $4.00.
[c] The landed LNG price is assumed to be 100 percent to 90 percent of the crude price on a Btu basis.
[d] California citygate price is estimated as the lower 48 wellhead gas price plus $0.50/MMBtu.

The difference between the competing fuel price and delivery costs is in the "Alaskan North Slope Wellhead Value in 2010" column.

Only the option for LNG shipment to California yields a positive North Slope wellhead value for the EIA Low Oil Price Case, which has a world oil price of $21.22 per barrel and an average U.S. wellhead gas price of $3.58 per MMBtu in 2010. The EIA Reference Case has a 2010 world oil price of $30.81 and a U.S. average wellhead gas price of $4.16. All options have positive wellhead values at the North Slope in the Reference Case; the Mackenzie Valley pipeline is the most attractive. All options also have positive wellhead values in the EIA High Oil Price Case, which has a 2010 world oil price of $37.08 and an average U.S. wellhead gas price of $4.00 per Mcf.[2] Note that the ranking of estimated netback wellhead values is different in the High Oil Price Case. Methanol sales to Japan and California and LNG sales to Japan are estimated to be more attractive than the Mackenzie Valley pipeline option.

The relative attractiveness of each option is highly dependent on price forecasts for oil products and natural gas at various locations. The pipeline options are expected to compete with U.S. and Canadian gas production; therefore, the projected average wellhead price is used as the benchmark competitive fuel price.[3] The price of gas at Caroline, Alberta, the terminus of both pipeline options, is assumed to be $0.80 per Mcf below the U.S. average; therefore, the full delivery charge for each pipeline option is the cost of transporting the gas to Caroline plus the $0.80 per Mcf differential between Caroline and an average U.S. wellhead price.

The LNG options can be expected to compete with other sources of LNG in Japan and with pipeline gas in California. The attractiveness of exporting LNG to Japan is driven by the alternative sources of LNG available to Japan and Japan's policies regarding diversification and security of supplies. In recent years, Japan has paid between $5.80 (1981) and about $4.25 (1990) for landed LNG (International Energy Agency 1991). This study assumes that incremental LNG is sold at a Btu parity with crude oil in the EIA Low Oil Price Case, yielding a year-2010 price of $3.94 per MMBtu. In the other cases, the study assumes that competition with other LNG sources, as well as pipeline sales from the former Soviet Union, keeps prices down. The Reference Case is evaluated as having LNG prices at 95 percent of crude and the High Oil Price Case is evaluated at 90 percent.

The methanol fuel options can be expected to compete with gasoline. The study assumes that methanol is marketed primarily in a blend with gasoline that sells at a discount to traditional motor-vehicle fuel (100 percent gasoline) because of the reduced heat content and that also receives some fuel-tax concessions. Table S–2 summarizes estimates of the wholesale value of methanol sold as a blending agent for M85. In this example, if gasoline sells at $1.19 per gallon at the pump, competing fuel-grade methanol will have a wholesale value of about $0.25 per gallon at the plantgate compared with an estimated wholesale value of $0.71 per gallon for gasoline (Energy and Environmental Analysis, Inc. 1988b). For the range of gasoline prices expected in the three EIA oil price scenarios, the wholesale plantgate methanol value in 2010 could range from $0.26 to $0.45 per gallon.

Further Considerations

The disposition of the Alaskan North Slope gas will depend on the basic economics of each option and the relative risk perceived by the entities making the necessary investment. All of the options involve the expenditure of billions of dollars and require several years of lead time; thus, it is possible that projects will not begin until several years after the necessary threshold prices are actually experienced in the market. Because of the complexity of the issue and budget constraints, this study did not attempt to address the economics of using the North Slope gas for EOR after 2010. The price of oil, new oil discoveries in the area, and technological advances in EOR may prove that continued use of the gas for EOR is the most economic option.

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[2] The gas price is lower in this case compared with the Reference Case because a higher production level of associated-dissolved gas depresses gas prices in a limited gas market.

[3] EIA projects only one average price for each case. There are no regional EIA wellhead gas price projections.

Table S-2 — U.S. Plantgate Methanol Value Given Competing Gasoline Price
(1988 dollars per gallon)

	Gasoline		M85
Gasoline Pump Price	1.185	Required M85 Pump Price (@ 1.74:1)	0.681
Federal Fuel Tax	0.141	Federal Fuel Tax	0.070
State Fuel Tax	0.179	State Fuel Tax	0.090
Sales Tax @ 5%	0.041	Sales Tax @ 5%	0.025
Total Taxes	0.361	Total Taxes	0.185
Pump Price Less Taxes	0.824	Pump Price Less Taxes	0.496
Outlet Markup	0.089	Outlet Markup	0.115
Trucking to Station	0.013	Trucking to Station	0.013
Terminal	0.016	Terminal	0.021
Total Distribution	0.118	Total Distribution	0.149
Wholesale Gasoline Price	0.706	Wholesale M85 Price	0.347
		Wholesale Gasoline Price	0.706
		Wholesale Methanol Price	0.284
		Trucking to Blender (100 Miles)	0.030
		Plantgate Methanol Price	0.254

Alternative Scenarios	2010 Gasoline Price	Plantgate Methanol Price
EIA Reference Case	1.46	0.384
EIA High Oil Price Case	1.61	0.454
EIA Low Oil Price Case	1.20	0.261

Source: Adapted from Energy and Environmental Analysis, Inc. 1988b.

I. NATURAL GAS RESOURCES OF THE ALASKAN NORTH SLOPE

INTRODUCTION

The natural gas resources on the North Slope of Alaska represent a potential source of fuel for highway vehicles in the United States. This gas could be used in the form of compressed natural gas (CNG), or it could be converted to methanol. Although the North Slope's oil resources currently provide about 10 percent of the petroleum consumed in the United States, the North Slope's gas resources remain mostly unused. This chapter summarizes estimates of the size of this gas resource base.

Figure I–1 is a map of Alaska showing the location of the North Slope region and the Trans-Alaska Pipeline System (TAPS). The Prudhoe Bay oil field is roughly halfway between Point Barrow on the west and the border with Canada on the east. The western portion of the North Slope is in the National Petroleum Reserve in Alaska (NPRA) while the eastern portion is in the Arctic National Wildlife Refuge (ANWR).

The oil and gas resources of the Alaskan North Slope can be classified as proved developed reserves, discovered undeveloped reserves, and undiscovered resources. The State of Alaska publishes estimates of proved developed reserves and discovered undeveloped reserves by field (Alaska Department of Natural Resources 1990). The Energy Information Administration (EIA) publishes annual estimates of statewide oil and gas proved reserves (U.S. Department of Energy 1989a). Undiscovered resources are assessed by the U.S. Geological Survey and the Minerals Management Service of the U.S. Department of the Interior (USGS/MMS) and the Potential Gas Committee (PGC) of the Colorado School of Mines (U.S. Geological Survey 1988; Colorado School of Mines 1988).

PROVED DEVELOPED GAS RESERVES

Table I–1 lists by field the proved developed oil and gas reserves on the Alaskan North Slope as of January 1, 1990. Almost all of the 28,042 billion cubic feet (bcf) of proved developed gas reserves are associated-dissolved gas, and the

Figure I–1 — Oil and Gas Accumulations on Alaskan North Slope

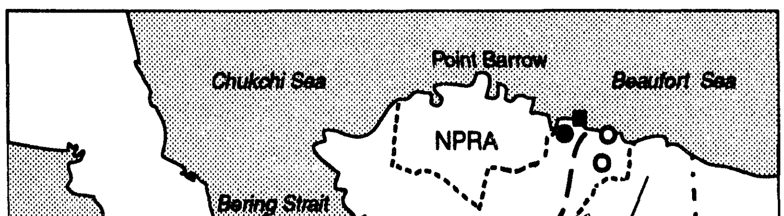


Table I–1 — North Slope Proved Developed Reserves as of January 1, 1990

Field	Discovery Year	Oil (MMB)	Oil (%)	Gas (bcf)	Gas (%[a])
Prudhoe (Sadlerochit)	1967	4,700	77.5	25,840	92.1
Prudhoe (Lisburne)	1967	150	2.5	888	3.2
Kuparuk River	1969	885	14.6	520	1.9
Endicott	1978	280	4.6	782	2.8
Milne Point	1969	50	0.8	0	0.0
East Barrow	1974	0	0.0	7	0.0
South Barrow	1949	0	0.0	5	0.0
Total		6,065	100.0	28,042	100.0

[a] Gas contains 10 to 12 percent carbon dioxide (approximately 3,000 bcf).
MMB = million barrels.

Source: Alaska Department of Natural Resources 1990.

great majority of these are associated with the Prudhoe Bay reservoirs. Figure I–2 shows the location of the developed and undeveloped oil and gas fields on the North Slope. Proved developed fields include South Barrow, East Barrow, Kuparuk, Milne Point, Prudhoe, and Endicott.

Because there is no pipeline outlet for produced gas, current production is either used in field production facilities, reinjected, or sold locally to TAPS. As a result, there is disagreement about how the gas should be classified. The State of Alaska carries the gas as proved reserves. However, EIA recently dropped most of the North Slope gas from the proved reserves category, providing the following rationale for doing so (U.S. Department of Energy 1989a):

> There has been an ongoing reassessment of North Slope gas resources for several years, with operators reporting major negative revisions in 1985 and 1987. There is a consensus among major Alaskan operating companies that, given the current economic conditions and outlook, only gas that is marketable on the North Slope should be classified as proved reserves. This is because large uncertainties exist about the availability of a gas transportation system or other marketing alternatives for the bulk of North Slope gas. The 24.6 trillion cubic feet of downward revisions to proved reserves on the Alaskan North Slope reported by the operating companies in 1987 and prior years now have been adopted by EIA.

Table I–2 shows 1989 North Slope associated-dissolved gas disposition by field. Production that year was 1,668 bcf. Of that amount, all but 211 bcf was reinjected. The 211 bcf represents gas that was either used in production facilities or sold locally.

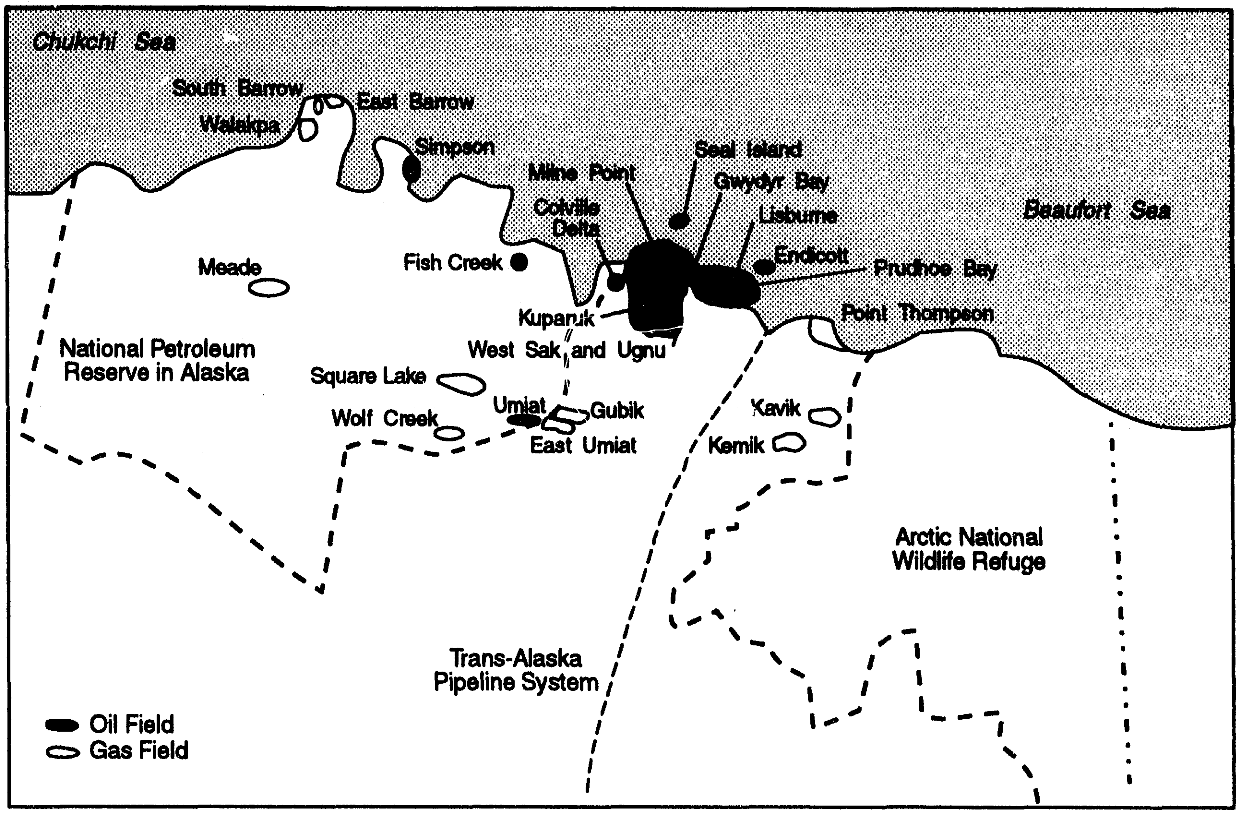
DISCOVERED UNDEVELOPED GAS RESERVES

Table I–3 shows estimated volumes of discovered undeveloped North Slope oil and gas. The Point Thompson field about 40 miles east of Prudhoe (Figure I–2) is the only field that has been assigned undeveloped gas reserves by the State of Alaska. The recoverable gas at Point Thompson is currently estimated to be 5,000 bcf.

Note that no gas reserves are listed for several large undeveloped oil fields, even though some of these fields contain associated-dissolved gas.

Several widely scattered nonassociated gas deposits have been found on the North Slope but have not been developed. These include Walapka, Meade, Square Lake, Wolf Creek, East Umiat, Gubik, Kemik, and Kavik

Figure I-2 — Oil and Gas Fields on Alaskan North Slope (Including Undeveloped Discoveries)



Source: U.S. Geological Survey Map I–1873, 1988.

(Figure I–2). Although these deposits have been informally named, they generally represent subeconomic wildcat discoveries. Undeveloped gas reserves in these fields total 373 bcf (Table I–3). When combined with the Point Thompson and Flaxman Island reserves, North Slope undeveloped nonassociated gas reserves total 5,373 bcf.

UNDISCOVERED CONVENTIONAL GAS RESOURCES

Tables I–4 and I–5 summarize 1988 PGC and USGS/MMS estimates of undiscovered conventional resources on the North Slope. PGC publishes estimates for three categories of gas: probable (reserve growth in existing fields), possible (new fields in current plays), and speculative (new fields in new plays). USGS/MMS publishes estimates of undiscovered fields for both oil and gas.

The 7,700 bcf listed as probable in the PGC estimate appear to include the undeveloped reserves of the Point Thompson field, mentioned above. The PGC estimate of conventional resources from new fields (possible and speculative) is 89,000 bcf. Of that, 38,000 bcf are expected from onshore areas, and 51,000 bcf are expected from offshore areas.

The USGS/MMS total for new fields is 68,680 bcf of gas, 16.08 billion barrels (Bbbl) of oil, and 1.06 billion barrels of natural gas liquids (NGL's). USGS/MMS (which contributed the offshore assessment) estimated that only 14,590 bcf of new field potential exists in the offshore areas of Northern Alaska. This is in contrast to the PGC estimate of 51,000 bcf. The USGS estimate of onshore potential is 54,090 bcf. Of this total, 22,110 bcf are expected to be found on the Arctic Coastal Plain. The remainder of the new field potential is in the foothills area to the south.

Table I-2 — Disposition of 1989 Alaskan North Slope Gas Production

	Prudhoe Bay		Endicott		Kuparuk		Milne Point		North Slope Total[a]	
Disposition	bcf/yr	MMcfd	bcf/yr	MMcfd	bcf/yr	MMcfd	bcf/yr	MMcfd	bcf/yr	MMcfd
Vented	6.46	17.7	0.07	0.2	0.19	0.5	0.07	0.2	6.79	18.6
Used	105.10	287.9	7.25	19.9	23.61	64.7	0.58	1.6	136.54	374.1
Sold	37.56	102.9	0.09	0.2	0.71	1.9	0.00	0.0	38.36	105.1
Shrinkage	8.69	23.8	0.99	2.7	0.00	0.0	0.00	0.0	9.68	26.5
Injected	1,340.00	3,671.2	33.03	90.5	83.32	228.3	0.32	0.9	1,456.67	3,990.9
Other	19.58	53.6	0.00	0.0	0.00	0.0	0.00	0.0	19.58	53.6
Gross Production	1,517.4	4,157.2	41.4	113.5	107.8	295.4	1.0	2.7	1,667.6	4,568.8
Noninjected	177.4	486.0	8.4	23.0	24.5	67.2	0.7	1.8	211.0	577.9
Percent of North Slope Gross	91.0		2.5		6.5		0		100.0	

[a]The gas production on this table represents almost all of the North Slope production. Two small, nonassociated fields produced a combined total of about 1 bcf in 1989. The gas from these fields is sold locally on the North Slope.
MMcfd = million cubic feet per day.

Source: Alaska Department of Natural Resources 1990.

ANWR contains a large portion of the region's oil and gas potential. The presence of large, untested structures and regional trapping conditions in this area provides excellent potential for new field discoveries. However, because of environmental considerations, future exploration and development activity in this area may be either restricted or prohibited. In 1987, USGS published an assessment of the oil and gas potential of the northern portion of ANWR (U.S. Geological Survey 1987). Seven plays were assessed for both in-place and economically recoverable resources. The mean estimates were 13.8 billion barrels of oil-in-place and 31,300 bcf of gas-in-place. Of the total gas-in-place, 16,700 bcf were expected to be nonassociated. Economically recoverable oil was estimated to be 2.21 billion barrels, with an uncertainty range of 0.59 to 9.24 billion barrels (95th to 5th percentiles). No scenarios were developed for economic exploitation of ANWR gas.

Presumably, the 1987 assessment of the northern portion of ANWR was incorporated into the 1988 USGS national assessment. However, in the 1988 report, USGS did not publish a separate estimate on ANWR.

UNCONVENTIONAL GAS RESOURCES

Extensive gas hydrate resources are present on the Alaskan North Slope and have been consistently observed in both exploratory and development wells. Gas hydrates are solid, crystalline compounds composed of natural gas and water molecules. They are stable only under specific pressure and temperature conditions. On the North Slope and in other arctic areas, they occur near the base of the permafrost layer at depths of several thousand feet. While considered an unconventional gas resource, gas hydrates have been produced in at least one large field in Siberia (U.S. Geological Survey 1990).

Preliminary resource appraisals in the Kuparuk River-Prudhoe Bay area indicate that 8 trillion cubic feet (tcf) to 10 tcf of gas hydrate is recoverable (U.S. Geological Survey 1990). Other published estimates indicate that up to

Table I–3 — North Slope Discovered Undeveloped Oil and Gas Reserves as of January 1, 1990

Field	Discovery Year	Oil (MMB)			Gas (bcf)		
		Low	Mid	High	Low	Mid	High
Beaufort Sea (Seal Island)	1984	0	150	300	0	0	0
Point Thompson / Flaxman Island	1977	0	0	300	0	5,000[a]	5,000
West Sak Heavy Oil	1971	0	500	3,000	0	0	0
Niakuk	1984	0	50	80	0	0	0
Point MacIntire	1989	150	200	300	0	0	0
Umiat[b]	1946	—	70	—	—	—	—
Ugnu Tar Sands[b]	1969	—	750	—	—	—	—
Meade[c]	1950	—	0	—	—	20	—
Square Lake[c]	1952	—	0	—	—	58	—
Gubik[c]	1951	—	0	—	—	295	—
Gwydyr Bay[c]	1969	—	60	—	—	—	—
North Prudhoe[c]	1970	—	75	—	—	—	—
Simpson[c]	1950	—	12	—	—	—	—
Total		150	1,867	3,980	0	5,373	5,000

[a] The State of Alaska reported 5,000 bcf for a high estimate and 0 for a middle estimate. The middle estimate is assumed to be 5,000 bcf on this table.
[b] As published in U.S. Geological Survey, 1989 Annual Report on Alaska's Mineral Resources.
[c] As published in U.S. Geological Survey, Open File Report 88–04504, 1991.

Source: Alaska Department of Natural Resources 1990.

Table I–4 — 1988 PGC "Most Likely" Estimates of Undiscovered Recoverable Gas on Alaskan North Slope
(billion cubic feet)

Area	Probable	Possible	Speculative	Total
North Slope Onshore	5,700	15,000	23,000	43,700
Beaufort Sea Shelf (0–200M)	2,000	12,000	19,500	33,500
Beaufort Sea Slope (200–1,000M)[a]				
Chukchi Sea Shelf (0–200M)			19,500	19,500
Total	7,700	27,000	62,000	96,700
New Field Total				89,000

[a] Not included in estimates.

Source: Colorado School of Mines 1988.

Table I–5 — 1988 USGS/MMS Estimates of Undiscovered Recoverable Oil and Gas on Alaskan North Slope

Area	Oil (Bbbl)	Gas (bcf)	NGL (Bbbl)
Arctic Coastal Plain	6.00	22,110	0.56
Northern Foothills	2.24	11,490	0.21
Southern Foothills	4.35	20,490	0.29
Beaufort Shelf	1.27	8,260	—
Chukchi Sea	2.22	6,330	—
Total	16.08	68,680	1.06

Source: U.S. Geological Survey 1988.

several hundred tcf of methane may be recoverable on the North Slope. Recovery of this resource will require development of new technologies that avoid melting the permafrost and associated subsidence.

In its 1990 report (Colorado School of Mines 1990), PGC published an estimate of the recoverable coalbed methane potential of Alaska. The most likely estimate of undeveloped potential was 57,000 bcf, with a range of 14,250 bcf to 95,000 bcf. The 57,000 bcf figure represents the potential from five areas, including the North Slope. PGC has not published a separate estimate for the North Slope, but it is known that this region contains the majority of Alaskan in-place coal with gas potential. According to USGS, the Cretaceous coals of the North Slope contain 3.2 trillion tons out of a total of 4.0 trillion tons of coal in Alaska (U.S. Geological Survey 1990).

II. PROPOSED OPTIONS FOR NORTH SLOPE GAS

INTRODUCTION

This section describes the following eight options for utilizing Alaskan North Slope natural gas after its current use for reinjection for pressure maintenance and enhanced oil recovery (EOR) ends, in approximately 2010:

- Pipeline to the lower 48 States via the Alaska Natural Gas Transportation System (ANGTS).
- Pipeline to the lower 48 States via the Mackenzie Valley pipeline.
- Liquefied natural gas (LNG) exports, LNG plant at Valdez.
- LNG exports, LNG plant on North Slope.
- Methanol conversion, plant at Valdez.
- Methanol conversion, plant on North Slope.
- Conversion to synthetic gasoline.
- Utilization for enhanced recovery of heavy oil.

Most of the gas produced on the North Slope is now reinjected. In 1989, the Prudhoe Bay injection rate was 3,670 million cubic feet per day (MMcfd) out of a gross production of 4,160 MMcfd, or 88 percent. The gas is reinjected to maintain reservoir pressure, to enhance oil recovery through miscible flooding; and to recover NGL's for transport through TAPS. Gas reinjection is also taking place at the Endicott and Kuparuk fields at a 1989 average rate of 320 MMcfd.

The Prudhoe Bay gas-processing facility is the largest such plant in the world, with an initial design throughput capacity of 3,300 MMcfd, producing up to 50,400 barrels per day of NGL's and up to 336 MMcfd of miscible injectant for tertiary oil recovery (*Oil and Gas Journal* 1988). Current plant capacity is 5,300 MMcfd following the GHX–1 gas-handling expansion completed in 1990 (*Alaska Oil and Gas Conservation Commission* 1991; *Oil and Gas Journal* 1990).

Separator offgas produces the inlet stream for the gas plant. There are three outlet streams:

- A salable stream of NGL's that is blended into the oil stream for delivery to TAPS.
- A miscible injectant stream that is delivered to EOR areas for injection.
- A residue gas stream that is delivered to the compression plant for reinjection into the reservoir. The field fuel requirement is also met with the residue gas.

In 1989, an average of 49,000 barrels per day of NGL's were recovered from the gas stream and about 200 MMcfd of light hydrocarbon miscible injectant were produced. Injected residue gas totaled about 3,500 MMcfd, while 300 MMcfd of residue gas were used as plant fuel.

The State of Alaska ruled in 1977 that up to 2 billion cubic feet per day (bcfd) (on an average annual basis) could be marketed from Prudhoe Bay without adversely affecting ultimate recovery (Alaska Oil and Gas Conservation Commission 1977). The marketing of 2 bcfd would involve gross production of 2.7 bcfd, taking into account processing losses and fuel consumption at the field.

Starting in 1988, oil production at Prudhoe Bay began to decline, despite the large-scale pressure-maintenance operation. Declining oil production and gas cap expansion caused the gas-to-oil ratios (GOR) of certain wells to increase, requiring either construction of additional gas-handling capacity or shutting in some wells. A second increase in gas-handling capacity (GHX–2) is expected to be completed by the mid-1990's, increasing capacity to 7,500 MMcfd (Alaska Oil and Gas Conservation Commission 1991).

Plans recently submitted to the State of Alaska show that the operators of Prudhoe Bay intend to use the produced gas for pressure maintenance, EOR, and recovery of NGL's until about 2010. The application requests approval to expand the existing Prudhoe Bay miscible gas project and to allow reservoir pressure to drop below 3,600 pounds per square inch (psi), the currently mandated lower limit for the project (Alaska Oil and Gas Conservation Commission 1991). The operators note that all known North Slope gas reserves would be insufficient to maintain the reservoir at that pressure.

After 20 years, oil production presumably will be nearly ended and the remaining gas could be produced for sale or used for EOR in other fields. The oil production projections published by the State of Alaska are carried out to 2016, when estimated daily production rates will have declined from the current rate of about 1.7 million barrels per day of crude oil and condensate to about 68,000 barrels per day (Alaska Department of Natural Resources 1992).

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

ANGTS, an all-pipeline route that would be used to market North Slope gas to the lower 48 States, would involve construction of new pipelines in Alaska and western Canada, originating at Prudhoe Bay on the North Slope (Figure II–1). After paralleling TAPS, the ANGTS pipeline would head southeast into Canada at Beaver Creek in the Yukon Territory, across British Columbia to the Boundary Lake area, and through Alberta to a link with the existing ANGTS "prebuild" at Caroline. The ANGTS "prebuild" sections to U.S. border crossings at Kingsgate, British Columbia, and Monchy, Saskatchewan, which have been in operation since 1981 and were recently expanded, deliver gas from Alberta to pipeline systems operated by Pacific Gas Transmission and Northern Border Pipeline Company. Through these systems, gas would flow to U.S. Midwest and west coast markets.

In 1977, Congress passed the Alaska Natural Gas Transportation Act [15 U.S.C. 719e(a)(5)], which approved the project and established it as the preferred option for marketing Alaskan gas. Under the act, any gas destined for sale in the lower 48 States must be transported through ANGTS. However, because of high costs and dramatic changes in market conditions, the line has never been built.

Project sponsors believe that ANGTS is the best option for marketing Alaskan gas because much of the system is already built, the project is supported by the Canadian and U.S. Governments, and reduced construction costs will make the project more competitive. As originally proposed, the project would take 5 years to construct and would have an operating life of 25 years.

A modified version of ANGTS could include the so-called Dempster Lateral to transport Mackenzie Delta reserves southward to the ANGTS main line near Whitehorse in the Yukon Territory (Figure II–1). In this configuration, the lower portion of ANGTS would carry both U.S. and Canadian gas.

MACKENZIE VALLEY PIPELINE

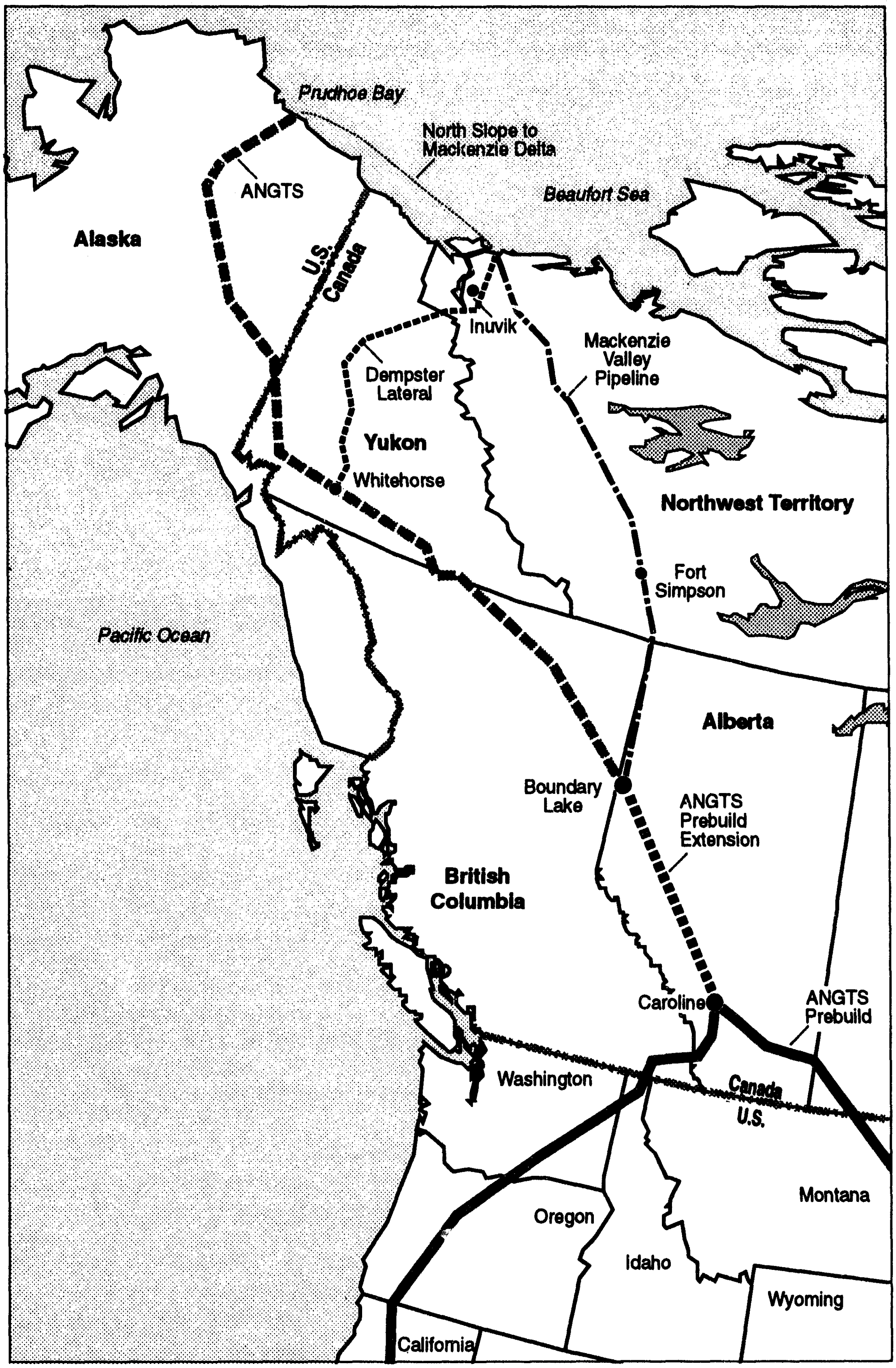
Another pipeline option for North Slope gas involves a tie-in to the proposed Canadian Mackenzie Valley pipeline, which would transport gas from discovered reserves in the Mackenzie Delta area of the Beaufort Sea.[1] Three systems have been proposed: the Polar Gas Project sponsored by Canada Pipeline, the Mackenzie Valley Pipeline sponsored by Foothills Pipe Lines Ltd. (the sponsor of ANGTS), and a third pipeline sponsored by the gas producers. In 1991, the three groups consolidated their proposals into one called the Mackenzie Delta Gas Pipeline.

If this pipeline is built, it might be possible to move Alaskan North Slope gas eastward to a connection point. From that point, the gas would flow southward to connect with the existing portion of ANGTS. An important issue will be the potential reluctance of the U.S. Congress to allow construction of a gas pipeline across ANWR. An alternative to an overland route would be an offshore pipeline laid in the shallow waters of the Beaufort Sea.

Three segments would have to be constructed for the Mackenzie Valley option: the North Slope segment, the Mackenzie Valley line, and an extension of the existing portion of ANGTS. In one possible option, the

[1] In 1989, the National Energy Board of Canada granted permits to export 9.2 tcf of Canadian reserves in the Mackenzie Delta area beginning in the late 1990's.

Figure II-1 — Alaska Natural Gas Pipeline Routes



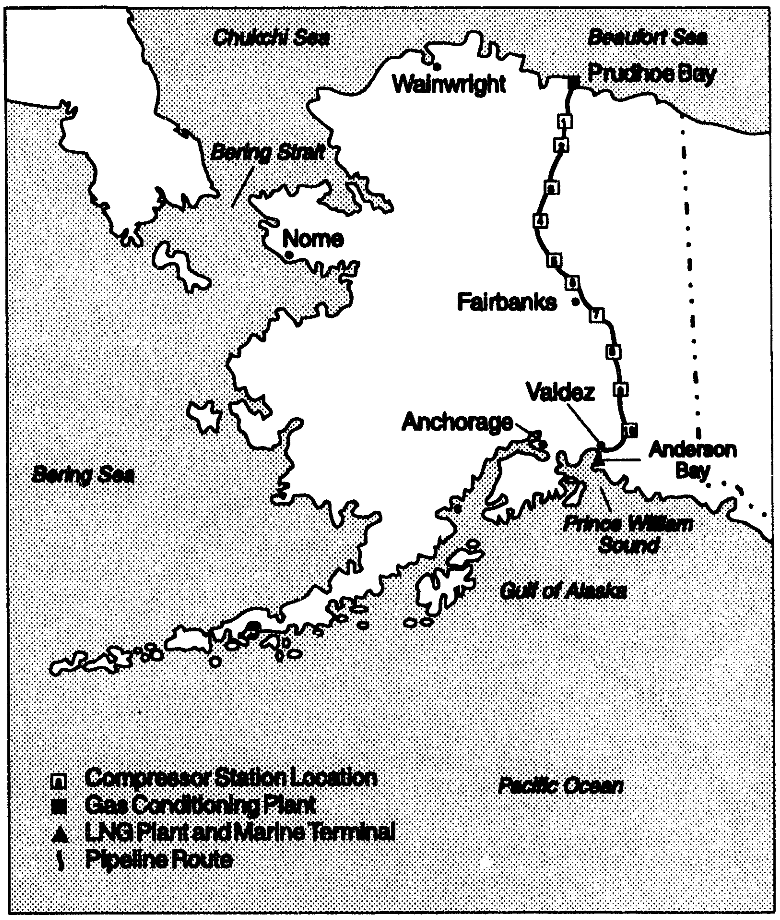
Mackenzie Valley line, extending from the Mackenzie Delta to Boundary Lake, Alberta, would consist of a 1,023-mile 34-inch pipeline with a capacity of 1.2 bcfd and a 407-mile 48-inch "prebuild" extension from Caroline to Boundary Lake (Figure II–1). This southern segment would initially have a capacity of 1.2 bcfd but could be upgraded to 2.4 bcfd to accommodate Alaskan gas when the segment between the North Slope and the Mackenzie Delta is warranted.

LIQUEFIED NATURAL GAS EXPORTS, PLANT AT VALDEZ

The Trans-Alaska Gas System (TAGS) was initially proposed in 1983. It consists of a gas pipeline paralleling the TAPS oil line and an LNG plant and port facility at Valdez (Figure II–2). The gas would be exported as LNG to the Pacific Rim countries of Korea, Japan, and Taiwan. Costs for the 800-mile buried line, the North Slope conditioning plant, the LNG plant, port facilities, and LNG tankers are estimated at $11 billion. The project sponsor is Yukon Pacific Corporation.

In November 1989, the Department of Energy approved a license allowing Yukon Pacific to export an average of 14 million metric tons per year of LNG, concluding that the project would not adversely affect gas prices, the industry's ability to meet U.S. demand, or the viability of ANGTS. The decision has been challenged by the sponsors of ANGTS, who believe that Alaskan gas will be in demand in the lower 48 States by the mid- to late 1990's.

Figure II–2 — Trans-Alaska Gas System



LIQUEFIED NATURAL GAS EXPORTS, PLANT ON NORTH SLOPE

Building an LNG facility on the North Slope would allow the gas to be transported to world markets in specialized tankers. Climate and accessibility would be major problems. A deepwater port facility would be required, necessitating construction of an extensive causeway into the Beaufort Sea. The port would be hampered with sea ice most of the year, and specially designed tankers would be needed to operate under these conditions.

Both icebreaking tankers and submarine tankers have been considered for this option (U.S. Department of Energy 1987). Submarine tankers could be used to transport LNG to the U.S. Northeast via an arctic route. The icebreaking tanker would be used to move gas to Pacific Rim markets.

METHANOL CONVERSION, PLANT AT VALDEZ

In this option, the gas would be transported to Valdez along a pipeline system similar to that proposed for TAGS. At Valdez, a plant would convert the gas to methanol, which would be shipped by tanker to U.S. and other markets.

METHANOL CONVERSION, PLANT ON NORTH SLOPE

In this option, natural gas would be converted to methanol on the North Slope. To reduce the costs of plant construction, methanol conversion facilities would be mounted on barges that could be beached or moored at Prudhoe Bay. The methanol could be transported to Valdez through a new pipeline built for that purpose.

As an alternative, the methanol could be transported through TAPS at the same time that oil is being transported. This would be achieved by shipping methanol either in a batch mode (that is, oil alternated with methanol) or as a mixture of oil dispersed in methanol. Special storage and handling facilities would be required at both ends of the line, and potential line and pump station operating problems would need to be addressed.

CONVERSION TO SYNTHETIC GASOLINE

Natural gas can be used as a feedstock to manufacture synthetic gasoline, which can then be blended into the crude oil pipeline and separated out at the refinery or sent through the pipeline in batches (U.S. Department of Energy 1987). This can be done in a two-step conversion process that is a fully developed, operational technology. In this process, natural gas is first converted to methanol and then to synthetic gasoline.

If an economic one-step conversion process is developed, North Slope gas could be converted in this manner and sent through TAPS. Research on several different direct conversion processes is being conducted by oil companies and by government research groups. At least two straight methane-to-gasoline conversion processes (one-step processes) are technically feasible and may soon advance to the stage of economic utilization (U.S. Department of Energy 1987). A less complex one-step process should have significantly lower capital and operating costs than current two-step processes.

Facilities for conversion of natural gas to liquids would be located on the North Slope. These facilities would include steam reformer and water-gas shift sections, a methanol conversion plant, and gasoline and distillate conversion units. Also included would be steam and power generation units. Prefabricated modules would be employed to allow phased production levels. As in the North Slope methanol conversion option, potential operating problems resulting from addition of gasoline to TAPS would have to be addressed.

ENHANCED RECOVERY OF HEAVY OIL

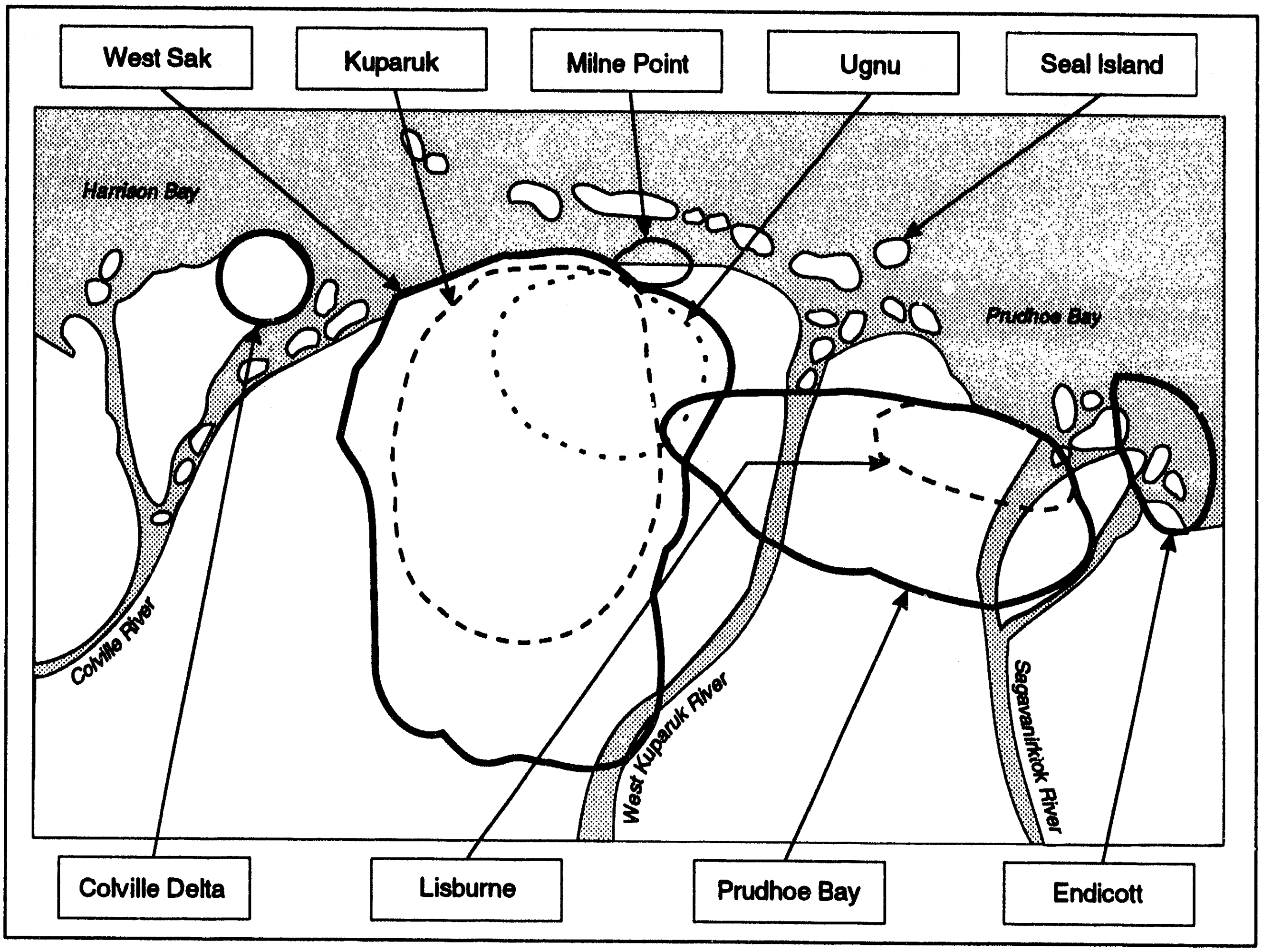
Vast deposits of heavy oil and tar-sand deposits have been identified on the Alaskan North Slope. This oil occurs in shallow sands west of Prudhoe Bay in the Kuparuk River field area. Using available gas for thermal and miscible EOR operations would essentially "convert" the gas to oil; the heavy oil could then be transported through TAPS.

Thermal EOR operations consist of hot-water flooding, steam cycling, or steam injection into the oil reservoir. Heavy, viscous oil deposits are particularly suited to this type of recovery. The injected water or steam reduces the viscosity of the oil and allows it to flow to the wellbore.

Two major North Slope heavy oil deposits have been identified: the West Sak heavy oil and the Ugnu tar sands. These deposits overlap each other and the deeper Kuparuk River reservoirs. The area encompassed is extensive—roughly twice the area of the Prudhoe Bay field (Figure II–3). Because both deposits occur in the same general area as the producing Kuparuk River field, existing infrastructure could be used for any eventual production.

The West Sak field is estimated to contain 15 billion to 25 billion barrels-in-place. A 1990 report from the State of Alaska indicates proved undeveloped reserves of 500 million barrels at West Sak, with a high estimate of 3 billion barrels (Alaska Department of Natural Resources 1990). The Ugnu tar sands field has been estimated to contain 15 billion barrels-in-place. USGS has published a

Figure II-3 — Location of North Slope Oil Fields



reserve estimate of 750 million barrels at Ugnu (U.S. Geological Survey 1990).

To recover the oil, it will be necessary to apply thermal EOR methods. A pilot hot-water flooding project is under way at the West Sak field. This project uses natural gas for boiler fuel and steam from cogeneration plants. The major impediment to the recovery of these oil deposits is the presence of permafrost and gas hydrates. It is unclear whether large-scale surface-based thermal EOR processes can be applied in this environment. Use of downhole steam generation facilities is under study and appears to be an attractive option.

It has been estimated that a full-scale thermal EOR operation could eventually utilize all of the Prudhoe Bay gas reserves (U.S. Department of Energy 1987).

III. ECONOMIC COMPARISON OF SELECTED OPTIONS FOR NORTH SLOPE GAS

INTRODUCTION

This section presents economic analyses of some of the options for using Alaskan North Slope gas. Because of the complexity of the issue and budget constraints, this study did not attempt to address the economics of using North Slope gas for EOR after 2010. Depending on the price of oil, new oil discoveries (if any) in the area, and technological advances in EOR, continued use of the gas for EOR may prove to be an economic option.

Comparisons of the economics of the options were made by computing wellhead values for the gas, assuming various selling prices for the products made from the gas. The wellhead value represents the North Slope price for the gas that would enable the product made from the gas to be sold in a specific market at the prevailing price (accounting for all production and transportation costs). For example, if the wholesale price of methanol is *x* cents per gallon in Los Angeles, the wellhead value of natural gas on the North Slope for that use would be *y* dollars per thousand cubic feet (Mcf).

Three options were reviewed in some detail:

- Transport to the lower 48 States by pipeline.
- Export of liquefied natural gas.
- Export of methanol.

Each of these options would require initial capital investments in the range of $10 billion to $15 billion. Construction, excluding any delays in obtaining permits, would take at least 4 years, depending on the location of facilities.

By presenting the wellhead value of the North Slope gas under various prices for the ultimate products, it is possible to compare the economic attractiveness of alternative uses for the gas.

TRANSPORT TO THE LOWER 48 STATES BY PIPELINE

The two options considered for transporting North Slope gas to the lower 48 States are ANGTS and a tie-in to a potential Mackenzie Valley pipeline system.

Alaska Natural Gas Transportation System

Original cost estimates for the 2.3-bfcd ANGTS project were $40 billion. In 1988, Foothills Pipe Lines Ltd., the principal sponsor of ANGTS, reestimated total ANGTS costs as $14.6 billion, which includes some $1.8 billion for expansion of existing lines in the lower 48 States. Including the existing segments, the overall cost would be $22.5 billion. The lower estimate was attributed to lower interest and inflation rates and advances in pipeline construction technology.

Physical parameters of the line are based on a 42- and 48-inch pipeline (between 2,160 and 1,680 pounds per square inch gauge) with a total length of approximately 1,700 miles.

Table III–1 shows a cost-of-service calculation for ANGTS based on total capital costs of $12.8 billion (1988 dollars). The costs are for the system cited above, excluding the lower 48 expansions. The calculation is based on the following important financial assumptions:

- Debt-to-equity ratio of 70:30.
- Nominal return on equity of 15 percent.
- Nominal cost of debt of 11 percent.
- Life of 20 years for rate purposes.
- Accelerated depreciation over 15 years for tax purposes.
- Inflation rate of 4 percent per year.

Table III-1 — Cost-of-Service Estimate for Alaska Natural Gas Transportation System
(millions of 1988 dollars)

Cost and Financial Assumptions

Total Capital Costs ($)	= 12,800[a]
Ratio of Equity to Total Capital	= 0.30
After-Tax Nominal Return on Equity (%)	= 15.0
Before-Tax Nominal Cost of Debt (%)	= 11.0
Useful Life for Ratemaking (years)	= 20
Inflation Rate (%)	= 4.0
Federal and State Income Tax Rate (%)	= 37.0
Annual O&M, Insurance, and Property Tax ($)	= 375[b]
Annual Throughput at 90% Capacity (bcf)	= 756
Calculated Average Before-Tax Nominal Return (%)	= 14.84
Calculated Average Before-Tax Real Return (%)	= 10.43

Annual Revenue Requirements

Year of Operation	Annual Deprec.	Net Plant	Cum. Deferred Taxes	Rate Base	Interest on Debt	Return on Equity	Tax on Equity Return	O&M Costs	Total Revenue Req'd.	Revenue Req'd. ($/Mcf)	Inflation Index	Real Revenue Req'd. ($/Mcf)
1	640	12,800	0	12,800	986	576	338	375	2,915	3.86	1.00	3.86
2	640	12,160	0	12,160	936	547	321	390	2,835	3.75	1.04	3.61
3	640	11,520	213	11,307	871	509	299	406	2,724	3.61	1.08	3.33
4	640	10,880	381	10,499	808	472	277	422	2,620	3.47	1.12	3.08
5	640	10,240	509	9,731	749	438	257	439	2,523	3.34	1.17	2.85
6	640	9,600	601	8,999	693	405	238	456	2,432	3.22	1.22	2.65
7	640	8,960	659	8,301	639	374	219	474	2,347	3.11	1.27	2.45
8	640	8,320	701	7,619	587	343	201	493	2,264	3.00	1.32	2.28
9	640	7,680	744	6,936	534	312	183	513	2,183	2.89	1.37	2.11
10	640	7,040	787	6,253	481	281	165	534	2,102	2.78	1.42	1.95
11	640	6,400	830	5,570	429	251	147	555	2,022	2.68	1.48	1.81
12	640	5,760	873	4,887	376	220	129	577	1,943	2.57	1.54	1.67
13	640	5,120	915	4,205	324	189	111	600	1,864	2.47	1.60	1.54
14	640	4,480	959	3,521	271	158	93	624	1,787	2.37	1.67	1.42
15	640	3,840	1,001	2,839	219	128	75	649	1,711	2.26	1.73	1.31

16	640	3,200	1,044	2,156	166	97	57	675	1,635	2.16	1.80	1.20
17	640	2,560	947	1,613	124	73	43	702	1,582	2.09	1.87	1.12
18	640	1,920	710	1,210	93	54	32	730	1,550	2.05	1.95	1.05
19	640	1,280	474	806	62	36	21	760	1,519	2.01	2.03	0.99
20	640	640	237	403	31	18	11	790	1,490	1.97	2.11	0.94
21	0	0	0	(0)	(0)	(0)	(0)	822	822	1.09	2.19	0.50
22	0	0	0	(0)	(0)	(0)	(0)	855	855	1.13	2.28	0.50
23	0	0	0	(0)	(0)	(0)	(0)	889	889	1.18	2.37	0.50
24	0	0	0	(0)	(0)	(0)	(0)	924	924	1.22	2.46	0.50
25	0	0	0	(0)	(0)	(0)	(0)	961	961	1.27	2.56	0.50
26	0	0	0	(0)	(0)	(0)	(0)	1,000	1,000	1.32	2.67	0.50
27	0	0	0	(0)	(0)	(0)	(0)	1,040	1,040	1.38	2.77	0.50
28	0	0	0	(0)	(0)	(0)	(0)	1,081	1,081	1.43	2.88	0.50
29	0	0	0	(0)	(0)	(0)	(0)	1,125	1,125	1.49	3.00	0.50
30	0	0	0	(0)	(0)	(0)	(0)	1,169	1,169	1.55	3.12	0.50
								5-Year Levelized Cost	2,751	3.64		3.40
								10-Year Levelized Cost	2,596	3.44		2.99
								20-Year Levelized Cost	2,433	3.22		2.56
								30-Year Levelized Cost	2,362	3.13		2.37

[a] Excludes approximately $1.8 billion in costs for expansion of pipelines in the United States. Includes $1.6 billion for gas conditioning plant.
[b] Excludes value of gas used as fuel.
O&M = operations and maintenance.

- Income tax rate of 37 percent.
- Throughput at 90 percent of capacity.

The cost-of-service calculation in Table III–1 follows conventional ratesetting practices in which the cost of service declines as the rate base is depreciated. The required return of equity used in this example and other examples of stand-alone pipelines on the Mackenzie Valley route is based on a reasonable allowable target return set by regulatory agencies. The nominal cost of service (total revenue required) is $3.86 per Mcf in the first year of service and declines to $3.75 per Mcf in the second year. By the last (20th) year, the cost of service in nominal dollars falls to $1.97 per Mcf. The last column of Table III–1 shows the cost of service in real dollars per Mcf. This value is $3.86 per Mcf in the first year and falls to $0.94 per Mcf in the 20th year.

It is also possible to express the cost of service in levelized terms—a constant value over *x* years that yields the same present value as the declining conventional rates. Various versions of levelized costs are shown at the bottom of Table III–1. For example, the nominal levelized value over the first 5 years is $3.64 per Mcf. This means that if the owners of ANGTS charge a constant nominal rate of $3.64 per Mcf over the first 5 years, they would receive the same discounted revenues as charging $3.86 in the first year, $3.75 in the second year, $3.61 in the third, $3.47 in the fourth, and $3.34 in the fifth.

A levelized cost of service can also be computed in real dollars. Over the first 5 years, the levelized real cost of service for ANGTS would be $3.40 per Mcf (1988 dollars). Over the first 10 years it would be $2.99 per Mcf, and over the 20-year useful life, $2.56 per Mcf.

The method used to charge pipeline users would depend on how the pipeline rates are set by the governmental authority with jurisdiction over the pipeline and the contract between the pipeline and the shipper. It has been suggested that high-cost pipeline projects such as ANGTS might need to charge levelized costs for at least the first several years of service to avoid high initial rates. This has the advantage of making the pipeline viable sooner in that the economic threshold price for the delivered gas can be lower. For example, if the minimum acceptable wellhead price to producers and the State of Alaska is $0.50 per Mcf, the price of gas at Caroline would have to be at least $4.36 per Mcf for the first-year transport rate of $3.86 per Mcf to be absorbed. On the other hand, if a real levelized transport rate of $2.99 per Mcf is charged over the first 10 years of service, the price at Caroline would need to reach only $3.49 per Mcf for ANGTS to be economically viable. The downside to levelized rates is that the project sponsors (and debt holders) get their money out of the project more slowly and thus sustain greater financial risk.

Theoretically, for purposes of economic comparison, the 20-year levelized rate should be used to compare pipeline projects because it represents the actual cost of a pipeline over its planned life. However, a value this low may be misleading in that project sponsors probably would not build the pipeline if that levelized rate were all that could be counted on when the project started. For purposes of economic comparison in this report, levelized rates over this first 10 years are used for pipelines.

Mackenzie Valley Gas Pipeline

The system for transporting Mackenzie Delta and Beaufort Sea gas would require about 1,430 miles of pipeline to Caroline, Alberta, with a capacity of about 1.2 bcfd. This might consist of a 407-mile segment from Caroline to Boundary Lake and a 1,023-mile segment from Boundary Lake to the Mackenzie Delta (see Figure II–1). The cost of such a system, shown in Table III–2 under "Phase 1," is $4.4 billion (1988 U.S. dollars).[1] As shown in Table III–3, the 10-year real levelized cost of service for such a system would be $1.87 per Mcf. The cost of expanding the Mackenzie Valley system to accommodate Alaskan gas is shown in Table III–2 under "Phase 2." The expanded system would include looping the 34-inch line between the Mackenzie Delta and Boundary Lake and adding compression to the

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[1]Pipeline cost estimates presented in this section are based on the Foothills Pipe Lines Ltd. application to the National Energy Board of Canada. Line pipe, charges for construction, right-of-way, the compression station, overhead, and additional funds used during construction are included. Phase 2 expansion costs have been reduced by the amount attributable to right-of-way and construction road costs, approximately 10 percent of the total.

Table III-2 — Mackenzie Valley Gas Pipeline Costs
(millions of 1988 U.S. dollars)

Pipeline Segment	Phase 1	Phase 2	Total
Boundary Lake to Caroline			
1.2-bcfd, 407-mile, 48-inch pipeline, no compression	1,300		1,300
1.2-bcfd, compression only		400	400
Mackenzie Delta to Boundary Lake			
1.2-bcfd, 1,023-mile, 34-inch pipeline with compression	3,100	2,790	5,890
Total	4,400	3,190	7,590

48-inch line between Boundary Lake and Caroline to accommodate an additional 1.2 bcfd from Alaska. The incremental costs are approximately $3.19 billion, which brings total costs to $7.59 billion. The cost of service, assuming that the entire system is built together, is shown in Table III–4. The 10-year levelized cost of service is $1.61 per Mcf.[2]

Additionally, a pipeline would have to be built over the approximately 350 miles from the North Slope to the Mackenzie Delta. This route would take the line through ANWR or use an offshore route in the Beaufort Sea. Such a system would have a cost of approximately $1.3 billion and a 10-year levelized cost of service of $0.57 (Table III–5). Combined with the $1.61 per Mcf for the segment from the Mackenzie Delta to Caroline, this brings total transport costs to $2.18 per Mcf, which is $0.81 per Mcf less than the ANGTS option.

However, the Mackenzie Valley route requires construction of a pipeline to carry Canadian gas from the delta area to Caroline. Such a project will not be economic until the average U.S. wellhead price reaches about $4.00 per Mcf. Costs of the first several Mackenzie Delta fields to be developed ranged from $0.48 to $1.28 per Mcf (National Energy Board of Canada 1988). Added to the $1.87 per Mcf pipeline costs to Caroline and the $0.80 per Mcf differential between Caroline and an average U.S. wellhead price, this yields a U.S. wellhead price of $3.95 per Mcf. Given this initial price obstacle, the true lower 48 threshold price for the Mackenzie Valley route for Alaskan gas is not much different from that of ANGTS.

Wellhead Value for Pipeline Sales to the Lower 48 States

Wellhead values for pipeline sales to the lower 48 States are shown in Table III–6. These values assume that the Alaskan North Slope gas is transported by pipeline to the lower 48 States to compete against a variety of possible lower 48 average wellhead gas prices. If the average lower 48 wellhead gas price is $4.00 per Mcf, the wellhead value of the North Slope gas would be $0.21 per Mcf if transported through ANGTS and $1.02 per Mcf if transported through a Mackenzie Valley system.

EXPORT OF LIQUEFIED NATURAL GAS

This subsection contains estimates of total costs beyond the wellhead for North Slope gas converted into LNG. Capital investments, operating expenses, and fuel consumption have been calculated as a dollar-per-Mcf cost that must be subtracted from the delivered price of the LNG to estimate wellhead revenue.

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[2]If the expansion for Alaskan gas is built after Phase 1 has substantially depreciated, transport costs for Alaskan gas could be lower. However, it is unlikely that the costs would fall below the incremental costs for the Alaskan expansion, which total $1.55 per Mcf on a 10-year real levelized basis.

Table III-3 — Cost-of-Service Estimate for Mackenzie Valley Gas Pipeline
(millions of 1988 dollars)

Cost and Financial Assumptions

Total Capital Costs ($)	= 4,400[a]
Ratio of Equity to Total Capital	= 0.30
After-Tax Nominal Return on Equity (%)	= 15.0
Before-Tax Nominal Cost of Debt (%)	= 11.0
Useful Life for Ratemaking (years)	= 20
Inflation Rate (%)	= 4.0
Federal and State Income Tax Rate (%)	= 37.0
Annual O&M, Insurance, and Property Tax ($)	= 90[b]
Annual Throughput at 90% Capacity (bcf)	= 394
Calculated Average Before-Tax Nominal Return (%)	= 14.84
Calcaulated Average Before-Tax Real Return (%)	= 10.43

Annual Revenue Requirements

Year of Operation	Annual Deprec.	Net Plant	Cum. Deferred Taxes	Rate Base	Interest on Debt	Return on Equity	Tax on Equity Return	O&M Costs	Total Revenue Req'd.	Revenue Req'd. ($/Mcf)	Inflation Index	Real Revenue Req'd. ($/Mcf)
1	220	4,400	0	4,400	339	198	116	90	963	2.44	1.00	2.44
2	220	4,180	0	4,180	322	188	110	94	934	2.37	1.04	2.28
3	220	3,960	73	3,887	299	175	103	97	894	2.27	1.08	2.10
4	220	3,740	131	3,609	278	162	95	101	857	2.17	1.12	1.93
5	220	3,520	175	3,345	258	151	88	105	822	2.08	1.17	1.78
6	220	3,300	206	3,094	238	139	82	109	789	2.00	1.22	1.64
7	220	3,080	226	2,854	220	128	75	114	757	1.92	1.27	1.52
8	220	2,860	241	2,619	202	118	69	118	727	1.84	1.32	1.40
9	220	2,640	256	2,384	184	107	63	123	697	1.77	1.37	1.29
10	220	2,420	271	2,149	166	97	57	128	667	1.69	1.42	1.19
11	220	2,200	285	1,915	147	86	51	133	637	1.62	1.48	1.09
12	220	1,980	300	1,680	129	76	44	139	608	1.54	1.54	1.00
13	220	1,760	315	1,445	111	65	38	144	579	1.47	1.60	0.92
14	220	1,540	330	1,210	93	54	32	150	550	1.39	1.67	0.84
15	220	1,320	344	976	75	44	26	156	521	1.32	1.73	0.76

16	220	1,100	359	741	57	33	20	162	492	1.25	1.80	0.69
17	220	880	326	554	43	25	15	169	471	1.19	1.87	0.64
18	220	660	244	416	32	19	11	175	457	1.16	1.95	0.60
19	220	440	163	277	21	12	7	182	443	1.12	2.03	0.56
20	220	220	81	139	11	6	4	190	430	1.09	2.11	0.52
21	0	0	0	(0)	(0)	(0)	(0)	197	197	0.50	2.19	0.23
22	0	0	0	(0)	(0)	(0)	(0)	205	205	0.52	2.28	0.23
23	0	0	0	(0)	(0)	(0)	(0)	213	213	0.54	2.37	0.23
24	0	0	0	(0)	(0)	(0)	(0)	222	222	0.56	2.46	0.23
25	0	0	0	(0)	(0)	(0)	(0)	231	231	0.59	2.56	0.23
26	0	0	0	(0)	(0)	(0)	(0)	240	240	0.61	2.67	0.23
27	0	0	0	(0)	(0)	(0)	(0)	250	250	0.63	2.77	0.23
28	0	0	0	(0)	(0)	(0)	(0)	260	260	0.66	2.88	0.23
29	0	0	0	(0)	(0)	(0)	(0)	270	270	0.68	3.00	0.23
30	0	0	0	(0)	(0)	(0)	(0)	281	281	0.71	3.12	0.23
								5-Year Levelized Cost	904	2.29		2.14
								10-Year Levelized Cost	848	2.15		1.87
								20-Year Levelized Cost	787	2.00		1.59
								30-Year Levelized Cost	760	1.93		1.46

[a] 1.2-bcfd pipeline from Mackenzie Delta to Caroline, Alberta.
[b] Excludes value of gas used as fuel.
O&M = operations and maintenance.

Table III–4 — Cost-of-Service Estimate for Mackenzie Valley Gas Pipeline With Expansion for Alaskan Gas
(millions of 1988 dollars)

Cost and Financial Assumptions

Total Capital Costs ($)	= 7,590[a]
Ratio of Equity to Total Capital	= 0.30
After-Tax Nominal Return on Equity (%)	= 15.0
Before-Tax Nominal Cost of Debt (%)	= 11.0
Useful Life for Ratemaking (years)	= 20
Inflation Rate (%)	= 4.0
Federal and State Income Tax Rate (%)	= 37.0
Annual O&M, Insurance, and Property Tax ($)	= 152[b]
Annual Throughput at 90% Capacity (bcf)	= 788
Calculated Average Before-Tax Nominal Return (%)	= 14.84
Calculated Average Before-Tax Real Return (%)	= 10.43

Annual Revenue Requirements

Year of Operation	Annual Deprec.	Net Plant	Cum. Deferred Taxes	Rate Base	Interest on Debt	Return on Equity	Tax on Equity Return	O&M Costs	Total Revenue Req'd.	Revenue Req'd. ($/Mcf)	Inflation Index	Real Revenue Req'd. ($/Mcf)
1	380	7,590	0	7,590	584	342	201	152	1,658	2.10	1.00	2.10
2	380	7,211	0	7,211	555	324	191	158	1,608	2.04	1.04	1.96
3	380	6,831	126	6,705	516	302	177	164	1,539	1.95	1.08	1.80
4	380	6,452	226	6,225	479	280	165	171	1,474	1.87	1.12	1.66
5	380	6,072	302	5,770	444	260	152	178	1,414	1.79	1.17	1.53
6	380	5,693	356	5,336	411	240	141	185	1,356	1.72	1.22	1.41
7	380	5,313	391	4,922	379	222	130	192	1,302	1.65	1.27	1.31
8	380	4,934	416	4,518	348	203	119	200	1,250	1.59	1.32	1.20
9	380	4,554	441	4,113	317	185	109	208	1,198	1.52	1.37	1.11
10	380	4,175	467	3,708	285	167	98	216	1,146	1.45	1.42	1.02
11	380	3,795	492	3,303	254	149	87	225	1,094	1.39	1.48	0.94
12	380	3,416	518	2,898	223	130	77	234	1,043	1.32	1.54	0.86
13	380	3,036	543	2,493	192	112	66	243	993	1.26	1.60	0.79
14	380	2,657	568	2,088	161	94	55	253	942	1.20	1.67	0.72

15	380	2,277	594	1,683	130	76	44	263	892	1.13	1.73	0.65
16	380	1,898	619	1,278	98	58	34	273	843	1.07	1.80	0.59
17	380	1,518	562	956	74	43	25	284	806	1.02	1.87	0.55
18	380	1,139	421	717	55	32	19	296	782	0.99	1.95	0.51
19	380	759	281	478	37	22	13	308	758	0.96	2.03	0.47
20	380	380	140	239	18	11	6	320	735	0.93	2.11	0.44
21	0	0	(0)	0	0	0	0	333	333	0.42	2.19	0.19
22	0	0	(0)	0	0	0	0	346	346	0.44	2.28	0.19
23	0	0	(0)	0	0	0	0	360	360	0.46	2.37	0.19
24	0	0	(0)	0	0	0	0	374	374	0.47	2.46	0.19
25	0	0	(0)	0	0	0	0	389	389	0.49	2.56	0.19
26	0	0	(0)	0	0	0	0	405	405	0.51	2.67	0.19
27	0	0	(0)	0	0	0	0	421	421	0.53	2.77	0.19
28	0	0	(0)	0	0	0	0	438	438	0.56	2.88	0.19
29	0	0	(0)	0	0	0	0	455	455	0.58	3.00	0.19
30	0	0	(0)	0	0	0	0	473	473	0.60	3.12	0.19
								5-Year Levelized Cost	1,555	1.97		1.84
								10-Year Levelized Cost	1,459	1.85		1.61
								20-Year Levelized Cost	1,354	1.72		1.36
								30-Year Levelized Cost	1,307	1.66		1.26

[a] 2.4-bcfd pipeline from Mackenzie Delta to Caroline, Alberta. Excludes segment to Alaska.
[b] Excludes value of gas used as fuel.
O&M = operations and maintenance.

Table III-5 — Cost-of-Service Estimate for Gas Pipeline From North Slope to Mackenzie Delta
(millions of 1988 dollars)

Cost and Financial Assumptions

Total Capital Costs ($)	= 1,300[a]
Ratio of Equity to Total Capital	= 0.30
After-Tax Nominal Return on Equity (%)	= 15.0
Before-Tax Nominal Cost of Debt (%)	= 11.0
Useful Life for Ratemaking (years)	= 20
Inflation Rate (%)	= 4.0
Federal and State Income Tax Rate (%)	= 37.0
Annual O&M, Insurance, and Property Tax ($)	= 33[b]
Annual Throughput at 90% Capacity (bcf)	= 394
Calculated Average Before-Tax Nominal Return (%)	= 14.84
Calculated Average Before-Tax Real Return (%)	= 10.43

Annual Revenue Requirements

Year of Operation	Annual Deprec.	Net Plant	Cum. Deferred Taxes	Rate Base	Interest on Debt	Return on Equity	Tax on Equity Return	O&M Costs	Total Revenue Req'd.	Revenue Req'd. ($/Mcf)	Inflation Index	Real Revenue Req'd. ($/Mcf)
1	65	1,300	0	1,300	100	59	34	33	290	0.74	1.00	0.74
2	65	1,235	0	1,235	95	56	33	34	282	0.72	1.04	0.69
3	65	1,170	22	1,148	88	52	30	35	271	0.69	1.08	0.63
4	65	1,105	39	1,066	82	48	28	37	260	0.66	1.12	0.59
5	65	1,040	52	988	76	44	26	38	250	0.63	1.17	0.54
6	65	975	61	914	70	41	24	40	240	0.61	1.22	0.50
7	65	910	67	843	65	38	22	41	231	0.59	1.27	0.46
8	65	845	71	774	60	35	20	43	223	0.56	1.32	0.43
9	65	780	76	704	54	32	19	44	214	0.54	1.37	0.40
10	65	715	80	635	49	29	17	46	206	0.52	1.42	0.37
11	65	650	84	566	44	25	15	48	197	0.50	1.48	0.34
12	65	585	89	496	38	22	13	50	189	0.48	1.54	0.31
13	65	520	93	427	33	19	11	52	180	0.46	1.60	0.29
14	65	455	97	358	28	16	9	54	172	0.44	1.67	0.26
15	65	390	102	288	22	13	8	56	164	0.42	1.73	0.24

16	65	325	106	219	17	10	6	59	156	0.40	1.80	0.22
17	65	260	96	164	13	7	4	61	150	0.38	1.87	0.20
18	65	195	72	123	9	6	3	63	147	0.37	1.95	0.19
19	65	130	48	82	6	4	2	66	143	0.36	2.03	0.18
20	65	65	24	41	3	2	1	68	140	0.35	2.11	0.17
21	0	0	0	(0)	(0)	(0)	(0)	71	71	0.18	2.19	0.08
22	0	0	0	(0)	(0)	(0)	(0)	74	74	0.19	2.28	0.08
23	0	0	0	(0)	(0)	(0)	(0)	77	77	0.20	2.37	0.08
24	0	0	0	(0)	(0)	(0)	(0)	80	80	0.20	2.46	0.08
25	0	0	0	(0)	(0)	(0)	(0)	83	83	0.21	2.56	0.08
26	0	0	0	(0)	(0)	(0)	(0)	87	87	0.22	2.67	0.08
27	0	0	0	(0)	(0)	(0)	(0)	90	90	0.23	2.77	0.08
28	0	0	0	(0)	(0)	(0)	(0)	94	94	0.24	2.88	0.08
29	0	0	0	(0)	(0)	(0)	(0)	97	97	0.25	3.00	0.08
30	0	0	0	(0)	(0)	(0)	(0)	101	101	0.26	3.12	0.08
								5-Year Levelized Cost	273	0.69		0.65
								10-Year Levelized Cost	257	0.65		0.57
								20-Year Levelized Cost	240	0.61		0.48
								30-Year Levelized Cost	232	0.59		0.45

[a] 1.2-bcfd pipeline from Alaskan North Slope to Mackenzie Delta.
[b] Excludes value of gas used as fuel.
O&M = operations and maintenance.

Table III-6 — Wellhead Value of North Slope Gas for Pipeline Transportation to Lower 48 States
(1988 U.S. dollars per thousand cubic feet)

Average U.S. Wellhead Gas Price	Average Gas Price at Caroline, Alberta[a]	North Slope Value Based on Cost of Transport via ANGTS[b]	North Slope Value Based on Cost of Transport via Mackenzie Valley System[c]
1.50	0.70	(2.29)	—
2.00	1.20	(1.79)	—
2.50	1.70	(1.29)	—
3.00	2.20	(0.79)	—
3.50	2.70	(0.29)	—
4.00	3.20	0.21	1.02
4.50	3.70	0.71	1.52
5.00	4.20	1.21	2.02
5.50	4.70	1.71	2.52
6.00	5.20	2.21	3.02

[a] Based on assumed $0.80 per MMBtu differential between average U.S. wellhead price and price at Caroline, Alberta.
[b] Based on $2.99 per Mcf ANGTS transport cost. This is the levelized cost over the first 10 years.
[c] Based on $2.18 transport cost. This is the 10-year levelized cost of $1.61 for the segment from the Mackenzie Delta to Caroline and $0.57 for the segment from the North Slope to the Mackenzie Delta.

Assumptions

The cost estimates are for an LNG plant located at Valdez, Alaska, supplied by a gas pipeline from the North Slope. LNG exports from Cook Inlet in southern Alaska to Japan began in 1969; these exports have totaled a little under 1 million metric tons per year over the last few years.

LNG projects require high front-end investments in liquefaction plants, tankers, marine terminals, storage at both ends, and regasification. Total investments for an LNG project are usually greater than those for pipeline transport except in cases such as ANGTS, where the pipeline must pass through difficult and remote terrain. However, LNG must bear the inherent risks and additional costs of transport by sea. This analysis costs LNG tankers separately because of their unique nature and dedication to a specific project. During the past few years, the cost of new LNG tankers has risen dramatically; thus, the number of new tankers dedicated to a project will have a significant effect on the project's cost.

The capital costs for an LNG plant are based on a 1.0-bcfd baseload plant with three liquefaction trains. This plant will produce about 7.0 million metric tons per year of LNG for export and will require 13 or more LNG tankers to transport the gas. Many of the LNG and methanol plant cost assumptions in this report are based on data in the Alternative Fuels Assessment technical report on methanol production and transportation costs (U.S. Department of Energy 1989b).

The value of gas at the wellhead is assumed to be after removal of impurities and NGL's for a nominal heating value of 1,100 British thermal units (Btu) per cubic foot. Depending on market conditions and pipeline requirements, gas delivered to a pipeline may be anywhere from 75 to 95 percent methane. Pipeline transport of gas does not require removal of all carbon dioxide content as does conversion to LNG. The composition of LNG may vary considerably, depending on the amount of hydrocarbon liquids removed. This study assumes the LNG is composed of roughly 91 percent methane, 6 percent ethane, 3 percent propane and heavier, and only traces of nitrogen.

LNG Port Location

An Alaska site for a large-scale gas conversion plant will require its own infrastructure, including administrative buildings; general utilities; pollution control, steam generation, cooling water, electrical distribution, and water treatment systems; and storage for raw materials and the end product. Construction and operation of a complex plant and tanker loading facility in a remote location will have significant influence on the design. Reliability of operations will be the most important consideration; consequently, the design will include some overcapacity, redundant power, and process and safety systems and will limit the use of untried technologies. Availability of a plentiful, relatively inexpensive fuel source (gas) may influence the choice between capital investments and operating expenses in areas such as waste-heat recovery. Shipping, loading, and erection capabilities may be restricted because of infrastructure, climate, or surface conditions.

For all of the reasons outlined in the previous paragraph, this study assumes that the LNG plant and tanker loading facility will be located at Valdez, near the existing terminus of TAPS. This scenario involves a natural gas pipeline constructed along the existing TAPS corridor from Prudhoe Bay to Valdez for delivery of the gas feedstock. The Valdez location offers a year-round, ice-free port with significant existing infrastructure related to oil operations. Use of the TAPS corridor, also envisioned by the TAGS proposal, should provide easier permitting and construction operations.

Alternative sites, such as Prudhoe Bay, Wainwright on the Chukchi Sea, or Nome on the Bering Strait, do not have the proximity to existing infrastructure that Valdez offers. Transportation of equipment and personnel to the Valdez area is much easier than to points along the north or west coasts of Alaska. However, the most important consideration ruling out a northern site for this facility is the capability to operate tankers on a regular schedule. No regular winter transit of the Bering Strait to Prudhoe Bay has been accomplished by commercial vessels. The Beaufort Sea is subject to potential near-shore ice movement year-round. During 6 to 9 months of the year, the Bering Strait contains heavy pack ice and ice pressure ridges. Costs for icebreaking tankers are two to three times those of normal service tankers, and such vessels would require accompaniment by icebreaking support vessels along much of the route from Prudhoe Bay. Vessels constructed to withstand ice may still become stuck or suffer propeller or rudder damage in as little as 2 to 3 feet of sea ice (National Petroleum Council 1981).

Pipeline to Valdez

Yukon Pacific, sponsor of TAGS, has targeted LNG exports of 14 million metric tons per year from the North Slope fields. The LNG plant will require about 2 bcfd of gas. Yukon Pacific has announced plans for a pipeline capable of transporting 2.3 bcfd along an 800-mile route from Prudhoe Bay to Anderson Bay, near Valdez. Pipeline cost estimates in this study are based on this route and on the operating parameters envisioned for the proposed ANGTS and Mackenzie Valley pipelines (*Oil and Gas Journal* 1991; National Energy Board of Canada 1989).

The total cost of service for a 2-bcfd pipeline is estimated to be approximately $1.04 per Mcf (1988 dollars). For purposes of economic comparison in this report, the pipeline is considered to be an integral part of the LNG project and the cost of service calculated is equivalent to a 15-year levelized rate.[3] This cost estimate is based on a total pipeline cost of $3.6 billion, including compression, overhead, and funds used during construction. The entire length of the pipeline is assumed to be buried. Compression requirements are to be met by eight stations (about 440,000 horsepower) installed at 100-mile intervals. Some of this compression will be used to chill the gas

[3]The return on equity used for dedicated gas supply pipelines in the LNG and methanol options is the same as that used for the other components of those projects (liquefaction plant, tankers, and regasification plant). The rate used, 20 percent nominal before-tax, is higher than the target rate used in the ANGTS and Mackenzie Valley pipeline examples because the LNG and methanol options may be considered riskier and therefore deserving of a higher return. The pipeline that is built would be dedicated to the project and may be nonjurisdictional. For these reasons, and for consistency in presenting the cost of the entire LNG or methanol option, the higher return on equity was chosen for the examples.

to below the freezing point of water to protect the permafrost. Operating pressure is assumed to be 1,680 psi (similar to the Mackenzie Valley and ANGTS proposals), with a maximum allowable pressure drop of 300 psi between stations. These parameters require a 42-inch pipeline.

Because the existing road along the TAPS corridor can be reused for construction and maintenance of a gas pipeline, the pipeline and compressor costs have been reduced by 10 percent from those for a new line through undeveloped territory.

Table III–7 contains the costing methodology and financial parameters used to develop the pipeline cost of service.

Liquefaction Plant

LNG plants are basically refrigeration cycles for cooling the feedstock natural gas. The cooling cycle may use separate refrigerant circuits or use the various components of the feedstock natural gas in the refrigeration cycle. Methane, the lightest component in natural gas, boils at about –161 degrees Celsius. Other gases in the natural gas mixture liquefy at higher temperatures and may be removed during the liquefaction process. Carbon dioxide must be removed because it becomes a solid at this low temperature.

The size of liquefaction facilities is usually measured in tons of output. One metric ton of LNG (assuming 91 percent methane) is

Table III–7 — Bases for Cost-of-Service Estimate for Gas Pipeline From Prudhoe Bay to Valdez
(1988 dollars)

- 800-mile, 42-inch pipeline, with operating pressure of 1,680 psi.
- Total capital costs of $3.62 billion.
  - Includes pipeline costs of $2.5 million per mile.
  - Includes compression costs of $3,700 per installed horsepower.
  - Includes 21 percent overhead and 34 percent additional funds used during construction.
- Capital charges at 20 percent of total fixed investment. This charge is equivalent to a 10-percent real after-tax rate of return with the following parameters:
  - 15-year project life.
  - Debt-to-equity ratio of 2:3.
  - Nominal before-tax return on equity of 20 percent, debt financed at 10 percent before tax.
  - Income tax rate of 37.3 percent.
  - Depreciation 15 years (straight line).
  - Inflation at 4.0 percent per year.
- Operating factor of 95 percent (346 days per year).
- Annual operations and maintenance costs at 1.0 percent of total capital expenditure.
- Insurance, property taxes, working capital amortization at 2.4 percent of total capital expenditure.
- Labor costs (25 persons) of $1 million per year.
- Direct overhead at 45 percent of labor.

approximately 47,400 standard cubic feet (scf) of gas, and 1 million metric tons of LNG is approximately 47.4 bcf. A typical plant consists of two or more trains, each with an annual capacity of 2 million to 3 million metric tons of LNG. To estimate a per-Mcf unit cost, this study assumes a plant size capable of producing 1.0 bcfd. Of the 1.0 bcfd, about 10 percent is used as plant fuel, leaving 0.9 bcfd to be liquefied into 7.0 million metric tons of LNG per year.

The majority of investment in an LNG plant is normally for the equipment required to transform the raw gas feedstock. This is commonly designated equipment inside the battery limits (ISBL). Facilities outside the battery limits (OSBL) include utilities, buildings, water and electrical systems, and product storage. Additional or increased infrastructure investments required because of the remote location of the example plant have been added as a separate OSBL item.

ISBL equipment includes all machinery and spare parts used in the completed facility, such as tanks, vessels, compressors, furnaces, and heat exchangers. Other direct costs that may be ISBL or OSBL include physical materials used in building the plant, including piping and accessories, insulation, concrete, paint, and structural steel. Indirect costs include construction overhead (field salaries and expenses, healthcare costs, labor and material for temporary construction facilities, equipment, and tools) and engineering (design and procurement effort, computer and travel expenses, and overhead).

Other plant costs include the owner's cost of financing during construction, the contractor's profit, process-technology licensing fees, and government permitting fees. Additional costs based on typical provisions for contingencies are also added to the estimate.

Total capital and operating expenses for the example LNG plant are summarized in Table III–8. The costs are based on a location that requires some additional infrastructure, such as water supply, access roads, tanker loading facilities, and employee housing. This additional infrastructure is estimated to be about 25 percent of the total plant costs, excluding the owner's costs and startup costs.

The cost of liquefying natural gas is estimated to be approximately $1.40 per Mcf, excluding the gas lost during the liquefaction process. This cost is based on an 18.5-percent capital recovery factor, roughly equivalent to a real rate of return of 10 percent. As with all capital-intensive investments, the per-unit costs for a natural gas liquefaction plant depend on the capacity utilization rate. This study assumes a 91-percent utilization factor.

The liquefaction process is energy-intensive, consuming 8 percent or more of the feedstock gas as fuel. For the example plant, this study assumes that 10 percent of the gas is used as fuel.

Tankers

The current level of world LNG trade fully employs the available fleet of LNG tankers. These tankers are constructed for specific, long-term gas-export projects and are essentially tied to the economics of those projects for 20 or more years. Most recently delivered tankers hold 125,000 cubic meters (2.66 bcf) of LNG. These ships are more than 270 meters in length and 47 meters wide (too wide for the Panama Canal). They are faster than tankers for refined products and average more than 18 knots per day while in transit. The LNG is carried in insulated vessels at essentially atmospheric pressure and a temperature of −161 degrees Celsius. Much of the propulsion fuel for the ship is obtained from the gas boiloff at about 0.17 percent per day of the initial load. This study also assumes that supplemental fuel oil will be required to fuel the ship.

The cost of building new LNG carriers has risen rapidly over the past several years as interest in natural gas has increased. This study assumes a cost of $230 million per tanker (1988 dollars) for estimating the per-unit cost of transporting LNG. The capital charge for a tanker is based on a high debt ratio (U.S. Department of Energy 1989), which yields a nominal after-tax cost of capital of 9.0 percent (4.8 percent real). Other costs include port fees at about $75,000 per round trip. Table III–9 summarizes total capital and operating expenses for LNG tankers.

Table III-8 — Bases for Cost-of-Service Estimate for Gas Liquefaction Plant at Valdez
(1988 dollars)

- 1.0-bcfd baseload, approximately 7.0 million metric tons per year.
- Total capital costs of $2.225 billion:

Gas pretreating	$60 million
Liquefaction	$360 million
Utilities	$320 million
Auxiliary services	$90 million
Storage	$90 million
Loading facilities	$60 million
Marine facilities	$60 million
Construction overhead	$291 million
Engineering	$73 million
Contingencies	$211 million
Owner's cost	$161 million
Infrastructure	$404 million
Land	$10 million
Startup	$25 million
Working capital	$10 million

- Capital charges at 18.5 percent of total fixed investment. This charge is equivalent to a 10-percent real rate of return with the following parameters:
  - 15-year project life.
  - Debt-to-equity ratio of 2:3.
  - Nominal return on equity of 20 percent, debt financed at 10 percent.
  - Income tax rate of 37.3 percent.
  - Depreciation over 5 years (straight line) for ISBL.
  - Depreciation over 15 years (straight line) for OSBL.
  - Inflation at 4.0 percent per year.
- Working capital is approximately 3.0 percent of the fixed plant investment and represents feedstock and finished product inventory.
- Operating factor: 91 percent.
- Annual operations and maintenance costs at 3.0 percent of ISBL capital expenditure.
- Insurance and property taxes at 1.5 percent of total fixed capital expenditure.
- Labor costs (45 persons) of $1.8 million per year.
- Plant overhead at 65 percent of labor and maintenance.
- Direct overhead at 45 percent of labor.

Table III-9 — Bases for Cost-of-Service Estimate for Liquefied Natural Gas Carrier
(1988 dollars)

- 125,000 cubic meter capacity (2.66 bcf).
- Total capital costs of $230 million.
  - Working capital: $5 million.
- Capital charges at 13.4 percent of total fixed investment. This charge is equivalent to a 4.8-percent real rate of return with the following parameters:
  - 15-year project life.
  - Debt-to-equity ratio of 4:1.
  - Nominal return on equity of 20 percent, debt financed at 10 percent.
  - Income tax rate of 37.3 percent.
  - Depreciation over 15 years (straight line).
  - Inflation at 4.0 percent per year.
- Working capital is approximately 4.0 percent of the total investment and represents product inventory and supplies.
- Operating factor of 95 percent.
- Operations and maintenance costs (including insurance) of $6,000 per day.
- Supplemental fuel oil consumption at $1.9 million per year (average of 55 to 59 long tons per day).
- Labor costs (25 persons) of $875,000 per year.
- Direct overhead at 45 percent of labor.
- Port costs of $75,000 per round trip.

Table III-10 — Example Costs for Transport of Liquefied Natural Gas in a 125,000 Cubic Meter Tanker

Destination From Valdez	One-way Distance (mi)	Round Trips per Year	Annual LNG Loadings (bcf)	Gas Loss per Trip (%)	Transportation Cost ($/Mcf as loaded)
Los Angeles	2,056	28	74.5	1.6	0.58
Tokyo	3,400	19	50.5	2.6	0.84
Inchon	4,410	16	42.5	3.4	1.00
New Orleans	15,300	5	13.3	11.6	3.13

The economics of an LNG project are affected significantly by the distance between the liquefaction plant and the regasification terminal. Table III–10 summarizes LNG shipping costs to four locations from Valdez. Los Angeles is the closest, a 4,112-mile round trip. A tanker could make 28 trips per year between Alaska and Los Angeles, including 3 days port time per trip. (Actual loading and unloading time is less than 14 hours at each port.) Tokyo is a 6,800-mile round trip from Valdez, and a tanker could make 19 trips per year to Japan. Inchon, Korea, is an 8,820-mile round trip, requiring about 23 days. A trip to the U.S. Gulf Coast (Louisiana) assumes a route via Cape Horn. This trip covers 30,600 miles and takes 71 days—only 5 round trips per year.

Regasification Terminal

An LNG receiving terminal includes port facilities, offloading equipment, storage facilities, regasification equipment, and pipeline connections. Capital costs for a typical facility capable of handling an average of 500 MMcfd with peak daily capacity of 800 MMcfd are roughly $700 million (1988 dollars). Costs may vary significantly, depending on location.

Assuming capital costs of about $700 million, an overall real rate of return of 10 percent, a 95-percent capacity utilization rate, and other financial parameters similar to those used in the estimates for LNG liquefaction plants, LNG regasification costs are about $0.56 per Mcf (Energy and Environmental Analysis, Inc. 1988a).

Approximately 15,800 Btu of energy are required to vaporize 1 Mcf of LNG. If this energy is supplied by the feedstock LNG at an average of 1,100 Btu per Mcf vaporized, about 1.8 percent of the gas is used in the revaporization process. Additional energy requirements for compression and utilities bring total gas consumption to about 2.5 percent.

Wellhead Value for Export of Liquefied Natural Gas

Table III–11 outlines estimates of the wellhead value and the costs of the steps required to convert Alaskan North Slope gas to LNG and ship the LNG to the west coast of the United States or to Japan. Gas consumed as fuel is incorporated into the estimates of netback wellhead value. The example regasification plant tailgate revenue in Japan is based on the EIA crude oil forecast for 2010, Reference Price Case (U.S. Department of Energy 1992b). The example revenue in California is based on prices paid by Los Angeles citygate purchasers of pipeline gas.

The table is read from left to right, starting in the upper-left corner. If the average regasification plant tailgate revenue in Japan is $5.20 per Mcf, the LNG is worth $4.53 per Mcf equivalent at the tanker terminal landing after subtracting regasification costs. After subtracting tanker transportation charges,the gas is worth $3.59 per Mcf at the LNG liquefaction plant tailgate. Liquefaction costs reduce the gas value to $1.97 per Mcf at the Valdez pipeline terminus. Finally, after subtracting pipeline transportation charges from the North Slope, the gas is worth only $0.91 per Mcf at the wellhead. The North Slope wellhead breakeven price for LNG delivered at Tokyo is about $4.00 per Mcf. If the average regasification plant tailgate revenue in Los Angeles is $4.80 per Mcf, the wellhead value of North Slope gas would be $0.83 per Mcf. The breakeven revenue for LNG delivered at Los Angeles is about $3.82 per Mcf. Estimates of the wellhead value for a range of regasified LNG prices can be found in Table III–12.

EXPORT OF METHANOL

This subsection estimates the total costs beyond the wellhead for North Slope gas converted to methanol. Capital investments, operating expenses, and fuel consumption are calculated as a dollars-per-Mcf-equivalent cost that must be subtracted from the delivered price of the methanol to estimate wellhead revenue. Methanol is normally priced per gallon and would compete with crude oil in the world market for transportation fuel. To calculate a wellhead netback value, this study estimates the market value on a Btu basis for methanol that would compete with gasoline as a transportation fuel.

Assumptions

The detailed cost estimates presented here are for a methanol plant at Valdez, supplied by a gas pipeline from the North Slope. Although it may be feasible to convert gas to methanol

Table III-11 — Wellhead Netback Value Calculations for Liquefied Natural Gas
(1988 dollars per thousand cubic feet)

Location	Value	Processing/ Transportation Capital and O&M Costs	Gas Value, Excluding Losses	Gas Losses	Input Gas Value, After Losses	Processing/ Transportation Step
		LNG Delivery from North Slope to Japan[a]				
Regasification Plant Tailgate	5.20	0.56	4.64	2.5%	4.53	Regasification
Regasification Plant Inlet	4.53	0.84	3.69	2.6%	3.59	Tanker transport
Liquefaction Plant Tailgate	3.59	1.40	2.19	10.0%	1.97	Liquefaction
Trans-Alaska Pipeline Terminus (Valdez)	1.97	1.04	0.93	2.4%	0.91	Pipeline transport
North Slope Wellhead	0.91/Mcf 0.88/MMBtu					
		LNG Delivery from North Slope to California[b]				
Regasification Plant Tailgate	4.80	0.56	4.24	2.5%	4.13	Regasification
Regasification Plant Inlet	4.13	0.58	3.55	1.6%	3.50	Tanker transport
Liquefaction Plant Tailgate	3.50	1.40	2.10	10.0%	1.89	Liquefaction
Trans-Alaska Pipeline Terminus (Valdez)	1.89	1.04	0.85	2.4%	0.83	Pipeline transport
North Slope Wellhead	0.83/Mcf 0.80/MMBtu					

[a] Based on pipeline transport of North Slope gas to Valdez and tanker transport to Tokyo after liquefaction at Valdez.
[b] Based on pipeline transport of North Slope gas to Valdez and tanker transport to Los Angeles after liquefaction at Valdez.

on the North Slope and transport it to Valdez through either a dedicated methanol pipeline or through the existing TAPS line, that option was not considered in this analysis; however, a brief comparison of capital costs and operating considerations for a methanol plant located on the North Slope is included later in this subsection.

The costing methodology in this subsection is consistent with the analysis in the Alternative Fuels Assessment technical report on producing methanol from unutilized domestic natural gas (U.S. Department of Energy 1991). A methanol export project requires infrastructure and shipping facilities similar to those for an LNG project. Large front-end investments in conversion plants, tankers, marine terminals, and storage are required. Cost estimates for a methanol plant are based on a conceptual advanced-process conversion plant capable of producing 10,000 metric tons per day. Such a plant will consume about 300 MMcfd of inlet natural gas.

Table III-12 — Wellhead Value of North Slope Gas Sold as Liquefied Natural Gas
(1988 dollars per thousand Btu)

Delivered to Japan		Delivered to Los Angeles	
Delivered Regasified Price	North Slope Value	Delivered Regasified Price	North Slope Value
1.50	(2.08)	1.50	(1.86)
2.00	(1.66)	2.00	(1.44)
2.50	(1.25)	2.50	(1.02)
3.00	(0.83)	3.00	(0.60)
3.50	(0.41)	3.50	(0.17)
4.00	(0.01)	4.00	0.25
4.50	0.42	4.50	0.67
5.00	0.84	5.00	1.09
5.50	1.26	5.50	1.91
6.00	1.67	6.00	1.93

Methanol is produced by the reaction of synthesis gas (carbon oxides and hydrogen) over a catalyst. It is an alcohol of methane and may be used as a high-purity chemical product, directly as a fuel or additive to gasoline, or as a feedstock for methyl tertiary-butyl ether. The feedstock synthesis gas for methanol production is a chief determinant of the particular process system used. Light feedstocks such as methane are commonly processed by steam reforming and some combination with catalytic partial oxidation. Most modern methanol plants use a low-pressure process operating between 750 and 1,500 psi and between 230 and 280 degrees Celsius. Fuel-grade methanol requires less water removal and may contain higher alcohols and ethers. Carbon dioxide is both an intermediate product and a synthesis gas used in the methanol production process. Removal of carbon dioxide and nitrogen prior to methanol conversion is not necessary.

Low-pressure combination reforming methanol plants consume 28 million Btu (MMBtu) to 30 MMBtu of feedstock gas per metric ton (approximately equal to 333 gallons) of methanol produced. Consumption predictions for large-scale plants based on conceptual advanced designs are on the order of 29 to 31 MMBtu per metric ton. This study uses a conversion factor of 0.090 thousand standard cubic feet (Mscf) of feedstock gas per gallon of methanol produced.

Methanol is a safe, easily transported liquid that can be shipped in parcel tankers along with other chemical products. These ships carry separate storage and handling equipment for each of the products they transport. No special materials are required for methanol. If very large quantities of methanol are produced by one project, dedicated tankers can be built to handle transportation. Estimates for shipping costs in this study are based on typical petroleum-product carriers.

Methanol Port Location

For the same reasons as outlined in the subsection on LNG, this study assumes that the methanol will be exported from an ice-free port with some existing infrastructure. For the purposes of the cost analysis presented here, this study assumes that the loading facilities are located at Valdez.

Pipeline to Valdez

This study assumes that North Slope gas is delivered to Valdez through a gas pipeline and converted to methanol at Valdez. The cost-per-gallon equivalent of gas transported through the line and converted to methanol is based on the same pipeline throughput assumed in the LNG example. The transportation cost estimated for this 2-bcfd pipeline is $1.04 per Mcf (1988 dollars). The equivalent methanol transportation cost is $0.094 per gallon.

An alternative to transporting North Slope gas to Valdez for conversion to methanol at the point of export is converting the gas to methanol on the North Slope and then transporting the methanol to Valdez either through a dedicated methanol pipeline or with oil in the TAPS line. The cost of a 300-MMcfd methanol plant on the North Slope is estimated to be about $400 million greater than a similar plant at Valdez. This increases conversion costs by $1.06 per Mcf (or $0.10 per gallon of methanol). This increased cost alone is equivalent to the unit cost of transporting the gas through a gas pipeline to Valdez.

In addition to increased conversion costs on the North Slope, methanol produced on the North Slope must be transported to Valdez as a liquid. In 1988, Bechtel estimated the cost of a methanol pipeline paralleling TAPS at about $2.5 billion. This pipeline would carry 80,000 barrels per day of methanol (about 300 MMcfd) at a unit cost of $0.483 per gallon ($5.36 per Mcf) (Bechtel et al. 1989). Clearly, a large high-pressure gas line would be able to transport the methanol feedstock at a much lower cost.

Another alternative would be to send liquid methanol from the North Slope as batches or in a mixture with crude oil in TAPS. Methanol is normally shipped in dedicated railroad tank cars rather than product lines because of its affinity for water and other contaminants. The feasibility of transporting methanol through TAPS is highly dependent on the volume of oil pumped through the line, the ability to store large amounts of oil and methanol on the North Slope, and the cost of a distillation plant at Valdez to separate methanol from crude oil. Other potential operating problems that would need to be addressed are pump compatibility and the potential for periodic shut-in of oil wells during batch shipments. Given the uncertain technical feasibility and costs, the economics of shipment through TAPS are not examined here.

Conversion Plant

Current world-scale methanol plants process approximately 2,000 to 2,500 metric tons per day. The technology of methanol production is well known, and it is possible to build single-train plants with capacities of up to 3,000 metric tons per day. The 2.0 bcfd of gas that may be available from the North Slope could be converted into about 66,700 metric tons per day of methanol. The advanced plant assumed in this analysis has a capacity of 10,000 metric tons per day and uses improved process technology as well as some economies of scale. Such a plant is assumed to operate at higher pressure and thus achieve significant savings in gas compression costs. The synthesis gas generation is assumed to be two trains, but methanol synthesis and purification are essentially single trains.

As in the LNG plant example, costs for the methanol plant are based on construction at a site that requires some additional infrastructure. The methanol plant ISBL can be divided into the following major processing sections:

- Reforming the natural gas (reacting with steam or oxygen to form free hydrogen).
- Compressing the synthesis gas.
- Converting the synthesis gas to methanol (combining carbon dioxide and free hydrogen).
- Purifying the crude methanol by distillation.

Plant OSBL includes utilities, buildings, and storage. Direct overhead and other indirect costs are estimated as a portion of fixed capital expenditures. Table III–13 summarizes total capital and operating expenses.

The cost of converting natural gas to methanol is estimated to be about $2.44 per Mcf. This figure excludes feedstock costs but includes all gas consumed as fuel during the process. It is based on a capital recovery factor of 19.0 percent, roughly equivalent to a real rate of return of 10 percent. The equivalent methanol unit cost is $0.22 per gallon. Because methanol has roughly half the heat value of gasoline, the cost of the conversion process is

Table III-13 — Bases for Cost-of-Service Estimate for Methanol Production Plant at Valdez
(1988 dollars)

- 300-MMcfd baseload, approximately 10,000 metric tons per day.
- Total capital costs of $926 million:

Oxygen production	$122 million
Synthesis gas preparation	$86 million
Methanol synthesis	$88 million
Offsites	$119 million
Construction overhead	$116 million
Engineering	$29 million
Contingencies	$84 million
Owner's cost	$64 million
Infrastructure	$184 million
Chemicals	$12 million
Land	$9 million
Startup	$7 million
Working capital	$6 million

- Capital charges at 19 percent of total fixed investment. This charge is equivalent to a 10-percent real rate of return with the following parameters:
  - 15-year project life.
  - Debt-to-equity ratio of 2:3.
  - Nominal return on equity of 20 percent, debt financed at 10 percent.
  - Income tax rate of 37.3 percent.
  - Depreciation over 5 years (straight line) for ISBL.
  - Depreciation over 15 years (straight line) for OSBL.
  - Inflation at 4.0 percent per year.
- Working capital is approximately 4.3 percent of the fixed plant investment and represents feedstock and finished product inventory.
- Operating factor: 91 percent.
- Annual operations and maintenance costs at 6.0 percent of ISBL capital expenditure.
- Insurance and property taxes at 1.5 percent of total fixed capital expenditure.
- Labor costs (30 persons) of $1.2 million per year.
- Plant overhead at 65 percent of labor and maintenance.
- Direct overhead at 45 percent of labor.

equivalent to $0.44 per gallon (refinery gate) if used directly as a substitute transportation fuel. The actual wholesale value of methanol will be somewhat less than 50 percent of the value of gasoline because of transportation and storage costs and potentially different tax treatment.

Tankers

Shipping costs must be added to methanol production costs. Typical petroleum-product carriers are sized at 40,000 deadweight tons (DWT), although very-large-capacity crude carrier (VLCC)-type vessels sized up to 140,000 DWT are possible. Shipping costs in this report are based on newly built tankers dedicated to an Alaska methanol project. Vessels sized at 40,000 DWT designed for fuel-grade methanol transport are assumed to cost $23 million each. Fuel consumption is based on diesel engines and an average speed of 12 knots. Turnaround time is estimated at 2 days per trip and total operating time at 91 percent of the year (332 days).

Transportation costs for methanol are less than half those for transporting LNG after converting to a common per-Mcf cost and subtracting the gas boiloff in an LNG carrier. Table III–14 contains estimates of methanol shipping costs.

Wellhead Value for Methanol Export

Table III–15 outlines estimates of wellhead value and the costs of the steps required to convert Alaskan North Slope gas to methanol and ship the methanol to the west coast of the United States or to Japan. Gas consumed as fuel during conversion is incorporated into the estimates of netback wellhead value. The EIA Low Oil Price Forecast is used in these calculations. The example is based on the estimated wholesale value of methanol if it is used as a component of M85 (85 percent methanol, 15 percent gasoline) motor-vehicle fuel in competition with straight gasoline at the pump. The table is read from left to right, starting in the upper-left corner. In the case of sale to Japan, if the value of methanol at the import terminal landing is 26.10 cents per gallon, the methanol is worth only 22.47 cents per gallon at the Alaska export tailgate after subtracting tanker transportation charges. At the methanol conversion plant, the methanol is worth 0.47 cents per gallon after subtracting 22 cents per gallon in methanol conversion costs. The equivalent value as a gas is $0.05 per Mcf. After subtracting $1.04 per Mcf

Table III–14 — Example Costs for Methanol Transport in a 40,000-DWT Tanker

Destination from Valdez	One-way Distance (mi)	Round Trips per Year	Cost Component (¢/gal of methanol): Fuel	Capital	O&M	Port/ Canal	Total	Total Transportation Cost ($/Mcf equivalent)
Los Angeles	2,056	20	0.29	1.16	0.60	0.33	2.38	0.26
Tokyo	3,400	13	0.47	1.85	0.94	0.37	3.63	0.40
Inchon	4,410	10	0.60	2.34	1.19	0.37	4.50	0.50
New Orleans via Panama	6,400	7	0.98	3.59	1.70	1.11	7.38	0.82

Table III-15 — Wellhead Netback Value Calculations for Methanol
(1988 dollars)

Location	Value	Processing/ Transportation Capital and O&M Costs	Methanol Value, Excluding Losses	Gas Losses	Methanol Value, After Losses	Processing/ Transportation Step
			Methanol Delivery from North Slope to Japan[a]			
Methanol Terminal Landing (¢/gal)	26.10	3.63	22.47	—	22.47	Tanker transport
Methanol Plant Tailgate (¢/gal)	22.47	22.00	0.47	Included in conversion to methanol	0.47	Methanol conversion
Trans-Alaska Pipeline Terminus (Valdez) ($/Mcf)	0.05	1.04	(0.99)	2.4%	(0.96)	Pipeline transport
North Slope Wellhead:						
$/Mcf	(0.96)					
$/MMBtu	(0.94)					
			Methanol Delivery from North Slope to California[b]			
Methanol Terminal Landing (¢/gal)	26.10	2.38	23.72	—	23.72	Tanker transport
Methanol Plant Tailgate (¢/gal)	23.72	22.00	1.72	Included in conversion to methanol	1.72	Methanol conversion
Trans-Alaska Pipeline Terminus (Valdez) ($/Mcf)	0.19	1.04	(0.85)	2.4%	(0.83)	Pipeline transport
North Slope Wellhead:						
$/Mcf	(0.83)					
$/MMBtu	(0.80)					

[a] Based on pipeline transport of North Slope gas to Valdez and tanker transport to Tokyo after conversion to methanol at Valdez.
[b] Based on pipeline transport of North Slope gas to Valdez and tanker transport to Los Angeles after conversion to methanol at Valdez.

for pipeline transportation charges and accounting for fuel use, the wellhead value is a negative $0.96 per Mcf.

The calculations shown in Table III–16 outline the methodology used to estimate the wholesale value of fuel-grade methanol given a competing gasoline price. The EIA Low Oil Price Forecast of $1.20 per gallon of gasoline yields a wholesale methanol value of $0.261 per gallon.

If the average price of wholesale gasoline in Japan is $0.93 per gallon (based on the EIA Reference Case forecast of gasoline prices in 2010) and the corresponding value of methanol as a gasoline additive is $0.36 per gallon, the wellhead value of North Slope gas would

Table III-16 — U.S. Plantgate Methanol Value Given Competing Gasoline Price
(1988 dollars per gallon)

	Gasoline		M85
Gasoline Pump Price	1.185	Required M85 Pump Price (@ 1.74:1)	0.681
Federal Fuel Tax	0.141	Federal Fuel Tax	0.070
State Fuel Tax	0.179	State Fuel Tax	0.090
Sales Tax @ 5%	0.041	Sales Tax @ 5%	0.025
Total Taxes	0.361	Total Taxes	0.185
Pump Price Less Taxes	0.824	Pump Price Less Taxes	0.496
Outlet Markup	0.089	Outlet Markup	0.115
Trucking to Station	0.013	Trucking to Station	0.013
Terminal	0.016	Terminal	0.021
Total Distribution	0.118	Total Distribution	0.149
Wholesale Gasoline Price	0.706	Wholesale M85 Price	0.347
		Wholesale Gasoline Price	0.706
		Wholesale Methanol Price	0.284
		Trucking to Blender (100 Miles)	0.030
		Plantgate Methanol Price	0.254

Alternative Scenarios	2010 Gasoline Price	Plantgate Methanol Price
EIA Reference Case	1.46	0.384
EIA High Oil Price Case	1.61	0.454
EIA Low Oil Price Case	1.20	0.261

Source: Adapted from Energy and Environmental Analysis, Inc., *Capital and Operating Costs of a Fuel Methanol Distribution System—1988 Update*, October 1988.

be $0.15 per Mcf. The North Slope wellhead breakeven price for methanol delivered at Tokyo is about $0.35 per gallon. If the average price for wholesale gasoline in Los Angeles is $0.93 per gallon, the wellhead value of North Slope gas converted to methanol would be $0.29 per Mcf. The breakeven revenue for methanol delivered to Los Angeles is about $0.34 per gallon. Table III–17 contains estimates of the wellhead gas value for a range of delivered methanol prices.

Table III-17 — Wellhead Value of North Slope Gas Sold as Methanol
(1988 dollars)

Delivered to Japan		Delivered to Los Angeles	
Methanol Value ($/gal)	North Slope Value ($/MMBtu)	Methanol Value ($/gal)	North Slope Value ($/MMBtu)
0.175	(1.84)	0.175	(1.71)
0.225	(1.32)	0.225	(1.18)
0.275	(0.79)	0.275	(0.66)
0.325	(0.26)	0.325	(0.13)
0.375	0.26	0.375	0.40
0.425	0.79	0.425	0.92
0.475	1.32	0.475	1.45
0.525	1.84	0.525	1.98
0.575	2.37	0.575	2.50

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