Chapter 5
Economic Factors

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OVERVIEW

Exploration and development of oil and gas resources in the Arctic and deepwater frontiers depend largely on potential profitability. Economic incentives are needed for industry to develop the technology for resource development in the frontiers. Factors which influence project profitability include costs, timeframes, prices, markets, and government lease and tax payments. In general, higher costs and longer lead-times to production tend to lower profit margins in offshore frontier areas. As a result, the sensitivity of project economics to changes in various factors is higher in frontier areas than in mature producing regions such as nearshore Gulf of Mexico.

OTA has analyzed the economic attractiveness of oil and gas development in offshore frontier regions. Using a computer simulation model, cash flow profiles were developed for different types of offshore fields based on the technical scenarios presented in chapter 3. Ten hypothetical fields are discussed, consisting of representative large and small fields in nearshorc Gulf of Mexico, California deepwater, and three Alaskan basins. The estimates of costs, timeframes, and other variablcs used in the model are only approximations of those which may be encountered with actual projects in these offshore areas. The' results of the simulations do not represent the actual economics of prospects. They are used principally to illustrate how changes in economic factors can affect the profitability of oil and gas development in different offshore regions.

Remoteness, difficult operating conditions, and high engineering costs are characteristic of frontier areas. Extremely large oil and gas discoveries are needed to offset the high costs and long timeframes of exploration and development. Small fields may not yield adequate profits to justify development. The OTA analysis shows that while a 40- to 50-million barrel field may be profitable in the Gulf of Mexico, in the Alaskan offshore it may take a discovery of 1 to 2 billion barrels of recoverable reserves to make a project profitable.

Government lease and tax payments affect the profitability of offshore fields differently in the frontiers than in other leasing areas. The OTA computer simulation indicates that leasing systems based on alternative types of lease payments rather than fixed royalties may increase the profits and reduce some of the risks associated with frontier-area fields. In general, the profitability' of oil and gas development in offshore frontier areas will be increased by real oil and gas price increases. In the Alaskan regions, the availability of economic market outlets for oil and gas—the development of export markets for Alaskan oil and the development of processing and transportation systems for Alaskan natural gas—could improve the economic profile of offshore fields.

COSTS OF OFFSHORE EXPLORATION AND DEVELOPMENT

Harsh environments and difficult operating conditions, greatly increase the costs of' oil and gas exploration and development in Arctic and deepwater frontier regions. Costs are important determinants of the economic feasibility of producing oil and gas in offshore areas. In general, offshore exploration and development costs are influenced by the ocean environment (e. g., waves, ice, currents), water depth, field size and flow, proximity to support and transportation infrastructure, and elapsed time to production start up. Long lead-times to first production also add to the risks and uncertainty of frontier-area oil and gas activities.

The major categories of project costs—exploration costs, development costs, operating costs, and transportation costs—have been estimated for hypothetical small and large fields in five offshore regions (see table 5-l). These estimates are based on costs included in the National Petroleum Council study of ***U.S. Arctic Oil and Gas*** and other sources, and have been escalated to 1984 dollar equivalents. [1]hey are not exact figures, but are intended to be indicative of relative cost ranges in different offshore regions. More precise cost estimates can only be derived if and when a discovery is delineated and a production system is designed for a specific site and set of operating conditions.

Exploration Costs

Exploration costs include the cost of the drilling rig, logistical support, exploration wells, and delineation wells. They do not include the lease bonus payment. In this analysis, it is assumed that the wildcat exploratory success rate is 1 in 10 and that each successful discovery includes the cost of drilling 10 exploratory wells. In addition, it is assumed that five appraisal or delineation wells are drilled into each oilfield before development begins, except in the nearshore Gulf of Mexico where only three are drilled. Additional delineation wells are needed for frontier-area fields to justify the high costs of development.

Ocean environment and water depth account for most of the variation in exploration costs owing to requirements for specially designed drilling equipment in hostile environments and to operating conditions that may cause delays. Total exploration costs are generally independent of field size. The average cost of drilling exploratory and appraisal wells in the more conventional Gulf of Mexico leasing area is estimated at $6 million per well. In comparison, single exploratory wells are estimated to cost an average of $27 million in the California deepwater scenario and $55 million in the Navarin Basin of offshore Alaska. In this analysis, the total costs of an exploration program are estimated at $78 million in nearshore Gulf of Mexico as compared to $825 million in the Navarin Basin.

Development and Operating Costs

Development costs include the cost of the drilling platforms or islands and the development wells. In most regions, platforms and facilities account for 65 to 70 percent of total development costs. These costs vary not only with the harshness of the operating environment and water depth, but also with field size. In this analysis, it is assumed that there are no economies of scale associated with platform construction or development drilling, except in the nearshore Gulf of Mexico scenario. There are economies of scale associated with operating costs. Operating costs are calculated on an average annual basis and include labor, repair and maintenance, fuel, power, water, and other support functions.

Development costs for a 50-million barrel oil field in 400 feet of water in the Gulf of Mexico are estimated at $168 million, including platform costs of $112 million and drilling costs of $56 million. These costs escalate quickly with the depth of water and the severity of ice, wind, and wave conditions. Total development costs for a 300-million barrel field in California deepwater (3,300 feet) are estimated at $900 million. Development costs for a 2-billion barrel field in Alaska's Harrison Bay, which has severe ice conditions, are estimated at $6.3 billion, and in the Navarin Basin, with its greater water depth and harsher wind and wave conditions, at over $11 billion. Operating costs range from $10 to $25 million per year in the more temperate and accessible Gulf of Mexico and California regions to $100 to $250 million per year in the Alaskan offshore areas.

Transportation Costs

Transportation costs depend on many factors, including distance from markets, the availability of transportation infrastructure, and the harshness

[1]National Petroleum Council, U.S. ***Arctic*** Oil and ***Gas*** (December 1981); Dames and Moore, GMDI and Belmar Engineering, Deep ***Water Petroleum Exploration and Development in the California OCS,*** Report prepared for the Minerals Management Service (January 1984).

Table 5-1 .—Comparative Offshore Exploration and Development Costs (estimates for OTA computer simulation)

Area	Water depth (feet)	Field size (mmb)	Exploration cost ($ million)	Development cost ($ million)	Operating cost ($ mill/yr)	Transportation cost ($/bbl)	Production lead-times (years)
Gulf of Mexico							
Small field	400	15	78	105	7	$0.00	2
Large field	400	50	78	168	12	$0.00	2
Cal. Deepwater							
Small field	3300	150	400	450	16	$2.50	10
Large field	3300	300	400	900	24	$2.00	10
Norton Basin							
Small field	50	250	435	1038	72	$6.50	8
Large field	50	500	435	2076	102	$5.00	9
Harrison Bay							
Small field	50	1000	720	3162	120	$12.50	12
Large field	50	2000	720	6324	168	$10.00	12
Navarin Basin							
Small field	450	1000	825	5460	132	$6.50	11
Large field	450	2000	825	10920	240	$5.00	11

NOTE Costs refer to total, undiscounted outlays, in 1984 dollars.

SOURCE. Office of Technology Assessment.

of the operating environment. In this analysis, these costs are calculated on a per-barrel basis and include the cost of transporting oil from the production facility to the nearest U.S. market. Transportation costs include pipelines, tankers, and transshipment terminals. The costs of transporting oil to markets varies greatly among regions, but decreases with larger field sizes in all regions due to economies of scale.

Because of the availability of transportation systems and processing facilities in nearshore Gulf of Mexico and the ability to share pipelines, transportation costs are assumed to be absorbed in development costs in the Gulf fields. Transportation costs are estimated at $2 to $2.50 per barrel in the deepwater California area, where it is assumed that subsea pipelines are layed in extremely deep water to the West Coast. In the Norton and Navarin Basins of Alaska, where systems involve icebreaking tankers and transshipment terminals for transport to the lower 48 States, costs are estimated at $5 to $6.50 per barrel. The Harrison Bay project, where oil is transported to shore via pipeline and to southern transshipment terminals through the Trans-Alaskan Pipeline System (TAPS), is assumed to have a transportation cost per barrel of $10 to $12. The transportation costs for the California and Alaskan scenarios could be reduced by shared or common facilities which could serve several fields.

Photo credit: American Petroleum Institute

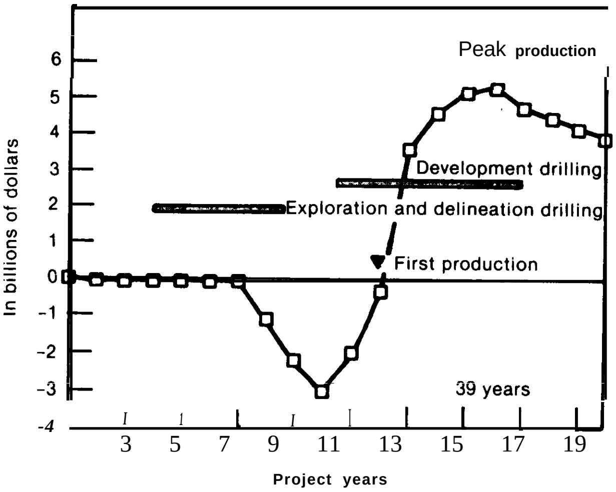
The existence of the Trans-Alaska Pipeline System (TAPS) will affect the economics of oil produced in the Beaufort Sea near Prudhoe Bay

Lead-Times to Production

Far longer time periods are needed for exploration and development in offshore frontier regions than in traditional areas. In the nearshore Gulf of Mexico scenarios, first production is assumed to occur 2 years after the lease sale. In contrast, in the California deepwater and Alaskan scenarios, first production does not begin until a minimum of 8 to 12 years after the lease sale. These schedules may underestimate the actual timeframes of activity in frontier regions, because they assume minimum time for obtaining necessary government approvals. The analysis also assumes that platform design will commence at the time of the discovery and proceed concurrently with the approval process.

For example, it is assumed in the Harrison Bay scenario that 5 to 6 years elapse between the time the lease is acquired and the time when a discovery is made (see figure 5-1). It takes another 5 to 6 years before permits are obtained and production facilities are designed and constructed. It is therefore a minimum of 12 years before the company sees a return on a sizable investment and the discovery contributes to cash flow. Peak production of 500,000 barrels per day occurs in the third year after beginning production. The total life of the field is 27 years from first production.

Figure 5-1.—Corporate Cash Flow
Harrison Bay — Large Field



SOURCE Off Ice of Technology Assessment

PROFITABILITY OF OFFSHORE DEVELOPMENT

Potential profits are the primary incentives for investments in offshore oil and gas exploration and development. In general, investments depend on finding suffcient recoverable reserves of marketable oil and/or gas to justify costs. In this analysis, the economic returns to industry and government from offshore oil and gas development are estimated by a computer simulation model (see box). This model calculates the net present value of all expenditures and revenues associated with the 10 hypothetical fields. By discounting these cash flows to the present, the analysis accounts for the time value of money and lost opportunities for alternative investments. The model includes a number of assumptions regarding prevailing economic conditions and the investment and production schedules associated with each oil field. It incorporates all relevant tax and leasing policies.

Economic Rent

The analysis of the net present value of investments has implications for the profitability of alternative investments and for the bidding behavior of firms for offshore leases. The net present value of offshore oil and gas development represents the profits available after a firm has received its normal return to capital, assumed in this analysis to be 10 percent per year. These profits are referred to as "excess profits' or ' 'economic rent. A firm's estimate of its share of the economic rent would be the upper limit to the amount it would be willing to bid as a bonus payment for the right to explore and develop an offshore tract. High competition in a lease sale might lead a firm to bid all of its economic rent as the bonus, leaving it with a normal return on its investment. If the estimate of a firm's economic rent is negative, this indicates that a firm may not make a normal return on the investment.

The Federal Government receives its share of the economic rent from a field in the form of taxes, including corporate income taxes and windfall profits taxes, and lease payments such as production royalties. The tax and leasing system selected by the government is intended to extract economic rent from offshore fields without destroying corporate incentives to undertake the required investments. In designing lease and tax payments, the government must balance the need to obtain fair market value for offshore leases with the need to provide the necessary incentives for development.

The calculation of the net present value of the 10 hypothetical offshore fields shows all of them to

OTA Computer Simulation Model

OTA and outside consultants have developed a computer simulation model to evaluate the economics of offshore oil and gas development projects. The model is based on a standard "discounted cash flow" analysis of the economic potential of investments. For each often hypothetical fields (small and large fields in the Gulf of Mexico, deepwater California, and three Alaskan regions), the model calculates the net present value of industry and government revenues based on prescribed parameters. **Some** of these parameters can be altered to evaluate the effects of changes in various factors on oil field economics.

The descriptive characteristics of the 10 hypothetical oil fields and associated costs are given in ***table* 5-1.** The simulation of each oil field is deterministic and follows field-specific investment and production schedules. The estimated costs and schedules are intended to be representative of **actual** conditions that oil companies may encounter in the offshore basins under consideration.

Other model inputs are financial parameters which describe the general economic environment in which exploration and development take place. Fiscal parameters incorporate applicable government tax and leasing regulations. The sensitivity of field economics to changes in prices, leasing systems, or taxes can be assessed by altering these parameters. The financial and fiscal parameters given below are those used in the base case model simulations.

Base* Case *Financial Parameters:

Crude oil market price, mid-1984 ($ per barrel)	$29.00
Growth rate of real oil price (annual)	O percent
General inflation rate	8 percent
Corporate discount rate (real terms)	10 percent
Project financing (debt/equity)	0 percent

Base Case Fiscal Parameters:

Production royalties (fixed)	12% percent
Rental fees (per acre)	$3.00
Corporate income tax (marginal rate)	46 percent

Taxable income was reduced by immediate expensing of dry hole costs and 80 percent of intangible drilling costs; depreciation of 20 percent of intangible drilling costs and 95 percent of tangible drilling coats; and the 10 percent investment tax credit.

Companies are assumed to have sufficient income from other sources in the United States to make use of all allowable tax deductions and credits as soon as they become available.

Financial calculations are baaed on a "ful-cycle" treatment of the exploration/development process. In the fixed royalty cases, the cost of nine dry wildcat wells is associated with each field (wildcat success rate of one in ten).

Windfall Profits Tax (1984 rate on new oil)	22.5 percent

The **Windfall Profits Tax does not apply to Arctic areas** and is scheduled **to expire after 1993. It thus should not affect frontier-area fields. In the model, this tax is only levied on the nearshore Gulf of Mexico fields.**

be profitable in terms of total available economic rent (see table 5-2). However, the government takes more than its share of the economic rent from two of these fields-the small fields in the Gulf of Mexico and in the high-cost Navarin Basin. In this analysis, Government payments include a royalty rate of 12½ percent and corporate income taxes on the deepwater and Arctic fields. Windfall profits taxes, which should expire by the time frontier-area fields begin production, are levied only on the near shore Gulf of Mexico fields. In addition, the Gulf of Mexico fields are assessed the traditional royalty rate of 16% percent. The fields which show a negative corporate net present value might not be developed under the assumed cost, price, and leasing conditions.

Minimum Economic Field Size

In high-cost offshore regions, very large field sizes are needed to offset exploration and development costs and still yield a normal return on investment. The amount of recoverable ***reserves*** needed to yield a normal economic return after subtracting costs and government payments is termed ' 'minimum economic field size. In the offshore frontier areas,

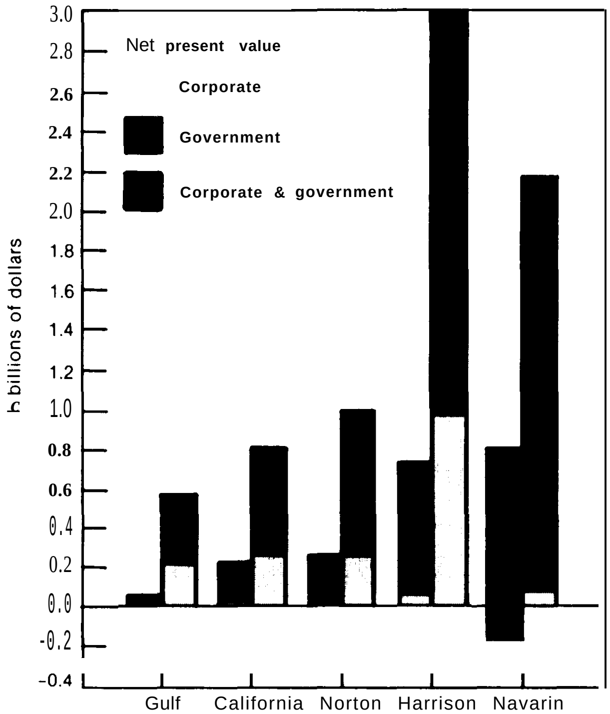
Table 5-2.—Profitability of Offshore Development
(from base runs of OTA computer simulation)*

Area	Water depth (feet)	Field size (mmb)	Net present value ($ million) Total	Corporate	Government	Government share (percent)
Gulf of Mexico						
Small field	400	15	62.9	-0.6	63.5	101
Large field	400	50	563.0	211.9	351.1	62
Cal. Deepwater						
Small field	3300	150	223.2	28.2	195.0	87
Large field	3300	300	807.2	264.1	543.1	67
Norton Basin						
Small field	50	250	261.9	7.6	254.3	97
Large field	50	500	978.0	264.4	713.6	73
Harrison Bay						
Small field	50	1000	735.2	81.8	653.4	89
Large field	50	2000	2989.4	955.8	2033.6	68
Navarin Basin						
Small field	450	1000	780.6	-149.9	930.5	119
Large field	450	2000	2176.5	121.2	2055.3	94

.Government payments include 12½ percent royalties and corporate income taxes on frontier fields; 16 2/3 percent royalties corporate income taxes, and windfall profits taxes on nearshore Gulf of Mexico fields.

SOURCE: Office of Technology Assessment

Figure 5.2.—Profitability of Offshore Development Small and Large Fields



SOURCE: Off Ice of Technology Assessment

far greater reserves are needed to yield profitable investments because of the greater costs and longer period of time over which these costs must be carried before repayment begins.

The analysis shows that reserves of approximately 40 to 50 million barrels of oil would support development in 400 feet of water in the Gulf of Mexico. However, a 100- to 150-million barrel field must be discovered to justify development costs in a deepwater environment, as in the California scenario, In the Alaskan offshore scenarios, minimum economic field sizes are as great as 250 to 500 million barrels of oil. In the difficult operating conditions of the Navarin Basin, even the l-billion barrel field may not be profitable for a company to develop (see figure 5-2).

GOVERNMENT LEASE AND TAX PAYMENTS

The combination of lease payments and taxes levied on offshore fields by the government affects the degree of profit- and risk-sharing between industry and government in oil and gas development. Activities in offshore frontier areas are differentiated by their small profit margins and their higher level of risk and uncertainty. For this reason, government payments affect frontier-area fields differently than those in other leasing areas.

Fixed Royalties

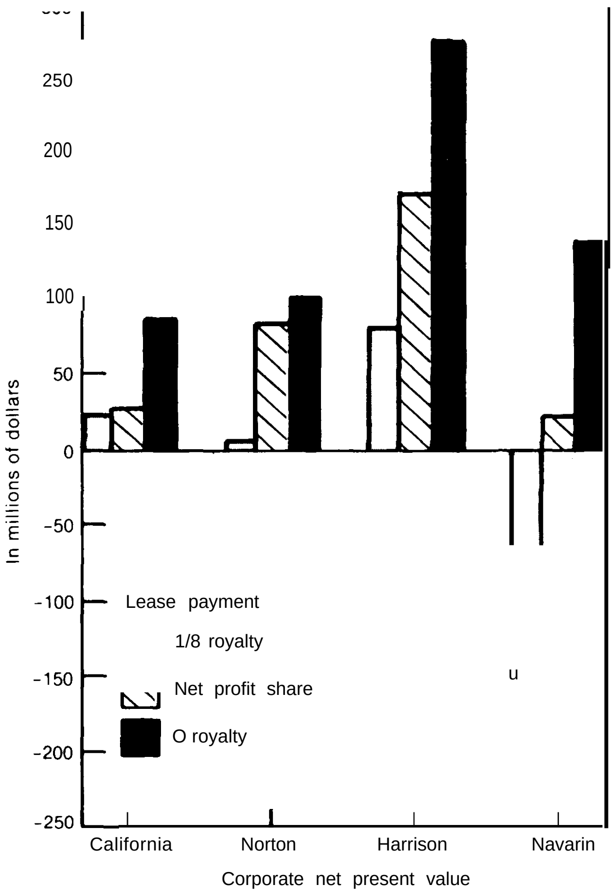
In addition to the initial cash bonus payment, lease payments in the United States traditionally have been fixed royalties based on the value of the resources produced. The royalty rate has been decreased from the standard 16 2/3 percent (one-sixth) to 12½ percent (one-eighth) in offshore frontier areas to improve the economics of resource development. Fixed royalties are levied on ***gross*** income and are counted as an addition to development costs in analyzing the potential profitability of projects. With fixed royalties, there is no allowance for such factors as field size, production costs, and lead-times to production when taking the government's share of the economic rent. In offshore frontier areas, where costs are higher and lead-times longer, fixed royalties may overtax fields and remove the economic incentive for development.

In general, royalty rates can alter production decisions on small or marginal fields, which in frontier areas may contain substantial resources. In the OTA analysis, the small field in the Navarin Basin is unprofitable to develop under fixed royalties, even though it is assumed to have reserves of 1 billion barrels of oil (see figure 5-3).

Other Lease Payments

Alternative lease payments may be more effective in promoting oil and gas development in offshore frontier areas. Profit-shares and sliding scale royalties are two types of payments believed to promote greater profit- and risk-sharing between industry and government. Eliminating lease payments would provide an even greater incentive to exploration and development in frontier areas. In

Figure 5-3.—Alternative Lease Payments Effect on Marginal Fields



SOURCE: Office of Technology Assessment.

this case, the government would receive its share of the economic rent through cash bonuses and taxes.

Although there are several types of profit-sharing systems, the United States has used a "fixed capital recovery' profit-sharing system in tests in offshore leasing. There have been 215 tracts sold with this type of lease payment between 1980 and 1983. Firms share at least 30 percent of their profits with the government, but first recover their initial investment and the cost of carrying that investment from year to year. Cost recovery is allowed according to a set formula or "capital recovery factor.

Because the lease payment is levied on net income, profit-sharing systems allow for the high costs of production in frontier areas and can provide incentives for the development of most field sizes. The capital recovery factor also takes into account the long timeframes of frontier-area projects, so that a company is not taxed too early in the life of the field. When profit-sharing with a 200 percent capital recovery factor is used as the lease payment in the OTA simulation, the small Navarin Basin field becomes profitable to develop (see figure 5-3).

The major disadvantage of profit-sharing systems is that they are more difficult to administer than royalty lease payments. In the fixed capital recovery system, profit share rates and capital recovery factors must be established prior to lease sales and calibrated to the operating conditions of different regions. Other types of profit-sharing systems, such as a symmetric system where the government shares in both profits and losses, could reduce the pre-lease analytic burden. Symmetric profit-sharing also has superior risk-sharing features. However, in most profit-sharing systems, the costs and profits associated with individual fields must be calculated and verified, thus requiring government access to industry cost information. Profit-sharing systems generally require more extensive recordkeeping on the part of both the industry and government.

The advantage of sliding scale royalties is that they vary with production rates, and thus extract a lower payment from smaller and/or less productive fields. However, the OTA analysis showed that sliding scale royalties perform no better than fixed royalties as neither can be set below the legal minimum of 12½ percent. Because of the low profit margins in frontier areas, most fields cannot bear a lease payment above the minimum royalty even at higher rates of production. A zero royalty or a sliding scale royalty which slides down to zero may be appropriate to high-cost frontier regions. A zero royalty makes the deepwater and Arctic fields far more profitable to develop (see figure 5-3).

PRICES AND MARKETS

Market Prices

Current and anticipated market prices are important incentives to exploration and development activities. Crude oil prices can have a major impact on the profitability of offshore frontier fields, particularly small or marginal fields, Fields which are uneconomic under current market conditions may be profitable given an increase in real crude oil prices. Similarly, decreases in real prices can remove the economic incentive to develop offshore resources. Present predictions are for real oil prices to decline in the short term and rise in the long term. Investments made now in oil and gas projects will be based on long-term views of energy markets, real price trends, and technological developments.

It is assumed in the OTA base case model simulations that there is no increase in the real price of oil, and that any associated natural gas is not produced because of low market prices or lack of available markets. According to the OTA analysis, a 1-percent increase in the real price of oil could substantially increase corporate returns (measured as net present value) for the oil field scenarios in offshore frontier areas. The previously unprofitable Navarin Basin field in Alaska becomes economic to develop with the real price increase. Higher oil prices, however, simply change the size of the marginal fields rather than eliminate them.

Alaskan Oil Markets: Export of Alaskan Oil

Restrictions on the export of Alaskan oil can result in increased costs of transporting offshore oil to U.S. consuming markets and reduce the profitability of Alaskan offshore fields. The Prudhoe Bay field, discovered on Alaska's North Slope in 1968, contains 10 billion barrels of oil reserves and is the largest single source of oil in the United States. In the 1970s, concern about dependence on foreign oil imports prompted Congress to enact a series of laws placing restrictions on the export of oil produced on Alaska's North Slope and in offshore areas. The Alaskan oil export restrictions of the

Export Administration Act of 1979 expired in February 1984. Currently, export of Alaskan oil is being restricted by other statutes.

About half of the oil now produced on the North Slope is shipped to California and West Coast markets, and the remainder is transported through the Panama Canal or the Trans-Panama Pipeline to U.S. markets on the Gulf Coast and Atlantic seaboard. Removing the ban on Alaskan oil exports to allow shipment to Asian markets could reduce the transportation costs of the producers, if these foreign markets could be developed. However, this could have negative impacts on the U.S. maritime industry now engaged in the Alaskan oil trade and on overall U.S. energy import requirements.

The cost of transporting Alaskan oil to the Gulf Coast is high because of the long distance and the requirement under the Merchant Marine Act of 1920 (the Jones Act) that this oil be carried in U.S. flag tankers. It is estimated that it costs $4.20 per barrel to ship oil from Alaska to the Gulf Coast in U.S. flag tankers as compared to a cost of $0.90 per barrel for shipment to Japan in U.S. flag tankers and $0.50 per barrel for shipment to Japan in foreign flag tankers[2] (see figure 5-4). A transportation cost savings from exporting Alaskan oil to closer markets could increase the wellhead price received for oil produced from onshore and offshore fields.[3] The higher profits, which would be distributed among the producers and Federal and State governments, may have effects similar to a price increase in improving the development prospects of marginal fields.

The North Slope tanker trade to the Gulf Coast currently engages approximately 40 percent of the ships in the U.S. tanker fleet and 65 percent of the U.S. shipping capacity. The U.S. Maritime Administration estimates that the loss from eliminating this trade would be 68 ships and over 4,000 jobs, and that it might also jeopardize $600 million in outstanding Federal loan guarantees on the tankers.[4] Many North Slope oil producers have investments in tanker capacity and also are ambivalent about exporting oil to markets outside the United States.

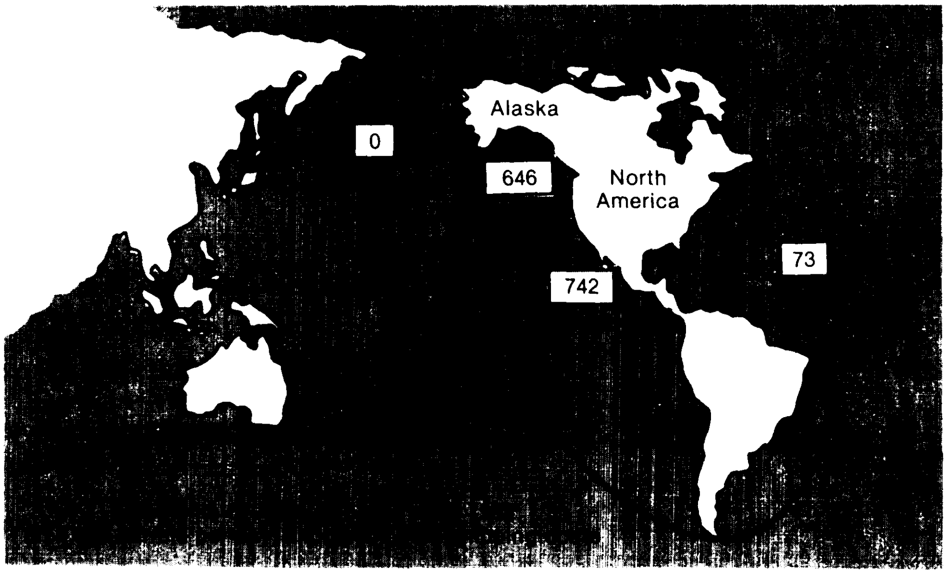
Small tankers needed by the Department of Defense in times of emergency could be displaced by removing the export ban. About one-third of the

[2]Stephen Eule and S Fred Singer, "Export of Alaskan Oil and Gas, " in *Free Market Energy, S.* Fred Singer (ed.) (New York: Universe Books, 1984), p. 123.

[3]Congressional Research Service, " Exports of Domestic Crude Oil (Dec. 8, 1983), pp CRS *4-6.*

[4]General Accounting Office, "Pros and Cons of Exporting Alaskan North Slope Oil" (Sept 26, 1983), p. 10

Figure 5-4.— Flow of Alaskan Crude Oil



SOURCE: Stephen Eule and S. Fred Singer, *Free Market Energy (New* York: Universe Books, 1984)

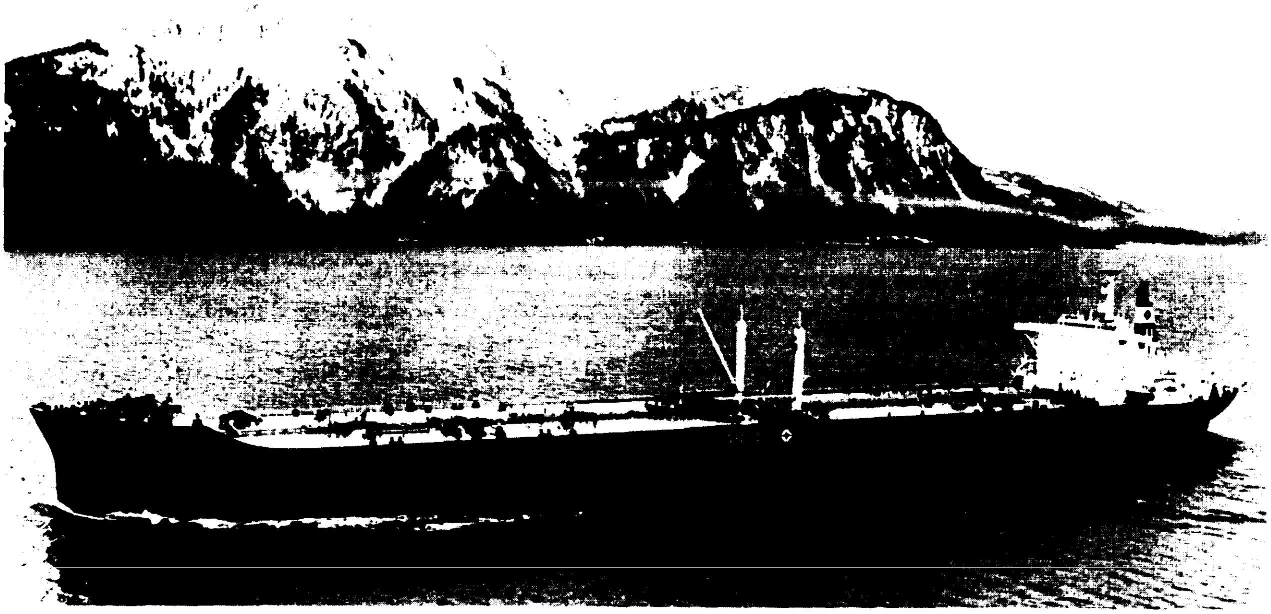


Photo credit: ARCO

Alaskan oil is now transported by tanker to refining centers in the lower 48 States

tankers used in the North Slope oil trade have potential military use because of their small size (less than 80,000 deadweight tons) which permits them to haul products into foreign harbors. It is estimated that removing the Alaskan oil export ban would eliminate about 13 percent of the supply of tankers available to the military for defense needs.[5] In addition, it would be difficult to ship Alaskan oil domestically in the event of a national emergency if this idle transportation capacity were eliminated.

Although exporting Alaskan oil to Japan could substantially improve the U.S. trade deficit with that country, it would somewhat increase the U.S. overall dependence on oil imports. Substitute oil for U.S. refineries could be imported partly from nearby sources such as Mexico and Venezuela, but a share also may be imported from Middle Eastern countries. This would decrease overall U.S. energy security, which the Alaskan oil export ban is designed to increase. In addition, severe economic losses would be suffered by Panama, which would lose revenues from the transit of Alaskan oil through the Panama Canal and the Trans-Panama Pipeline.

In the short-term, Japan is constrained in its need for U.S. oil by world energy surpluses and contractual commitments to other suppliers.[6] However, in the long term, Japan might benefit from access to a secure source of oil and might be more receptive to importing oil from Alaska. In addition, new oil reserves for throughput of the Trans-Alaskan pipeline will be needed as Prudhoe Bay production begins its decline in the late 1980s. Lifting the oil export ban for offshore fields, which probably will not come on stream until the mid-1990s or later, could provide an incentive to exploring and developing costly Arctic areas and new reserves for the pipeline.

Alaskan Natural Gas Markets: Alaskan Natural Gas Transportation System

A system for transporting Alaskan natural gas to U.S. consuming markets could also increase the profitability of Alaskan offshore fields. Planning and financing of the Alaskan Natural Gas Transporta-

[5] Congressional Research Service, "Exports of Domestic Crude Oil" (Dec. 8, 1983), p. 7.

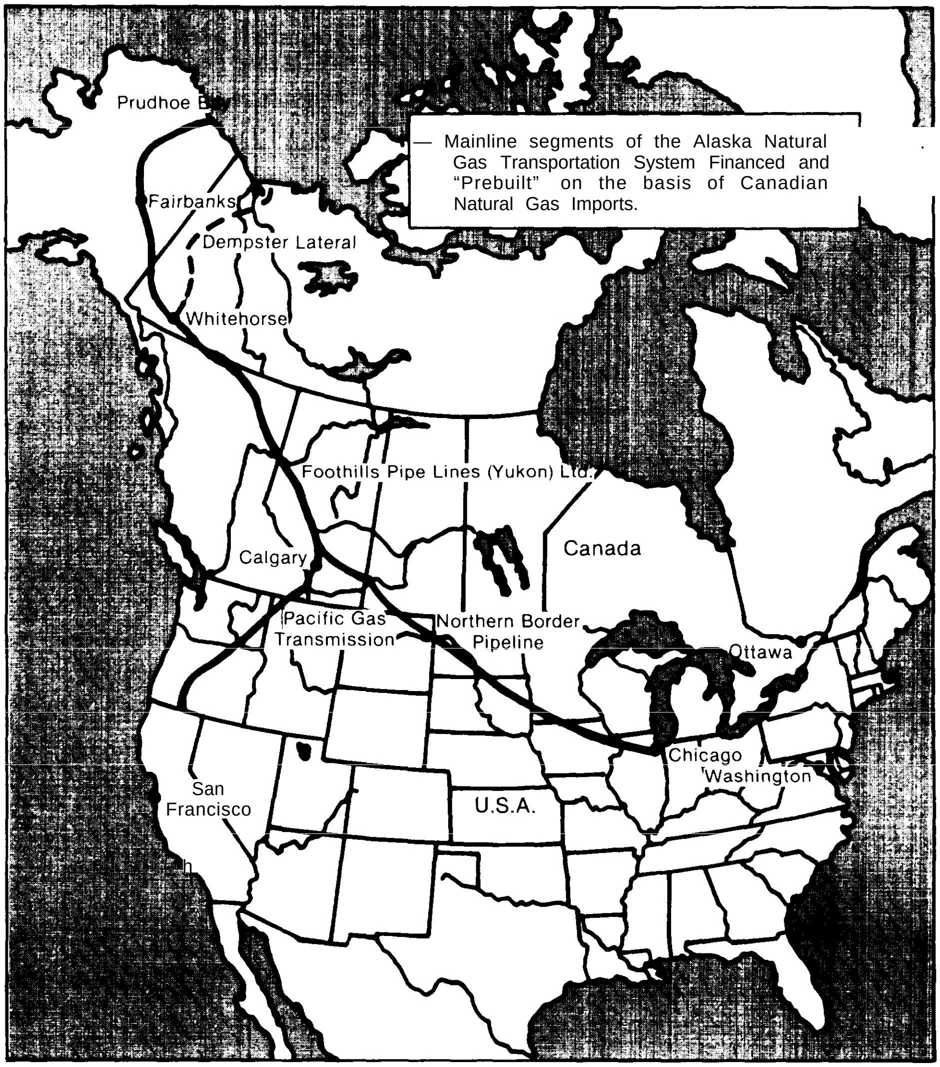
[6] "Japan Doesn't Want Alaskan Oil Anyway," *Business Week* (Mar. 12, 1984), p. 25.

tion System (ANGTS), the pipeline system intended to transport Alaskan natural gas to the lower 48 States, is currently on hold. Alternative processing and transportation systems have been proposed, but have the same cost and financing problems as the ANGTS.

Construction of the Alaskan segment of the pipeline has been postponed until economic and energy market conditions allow project financing. The ANGTS is designed as a 4,800-mile pipeline network carrying natural gas from Alaska's North Slope to the U.S. West Coast and the Midwest. Plans were made for the construction of the ANGTS during the domestic energy shortages and sharp oil price increases of the mid-1970s. However, by the time ANGTS plans were completed in 1981, there were energy surpluses and depressed prices. The only sections of the pipeline which have been completed are the Eastern and Western legs transporting natural gas from Calgary, Canada, to the U.S. West Coast and Midwest (see figure 5-5).

The potential high market price of Alaskan gas and associated marketing problems have been the main cause for a lack of financing for completing

Figure 5-5.—The Alaska Natural Gas Transportation System



SOURCE Off Ice of the Federal Inspector, Alaska Natural Gas Transportation System, Washington, D C the ANGTS. Current cost estimates of finishing the ANGTS are $40 to $50 billion, with the Alaskan segment alone estimated at $25 to $30 billion.[7] The tariff which would be charged to cover the costs of building the pipeline makes the projected price of Alaskan gas uncompetitive in its designated markets, in the short term. Estimates of the delivered price of Alaskan gas in 1989-90 are about $7.50 per thousand cubic feet, above the projected price of about $6.00 per thousand cubic feet for lower 48 gas in 1990.[6]

Alternative proposals to ANGTS include using Alaskan natural gas as raw material for a petrochemical facility or a methanol industry, or converting it to liquefied natural gas (LNG) for export to Japan. However, depressed world energy prices, marketing problems, limitations on Alaskan gas exports, and government commitments to ANGTS make these proposals unlikely alternatives to the pipeline system. A substantial increase in real gas prices may make the ANGTS or another Alaskan natural gas project economically feasible. A market outlet could be provided for natural gas now being produced, and reinfected, on Alaska's North Slope. In addition, the availability of natural gas processing and transportation infrastructure could improve the profitability of Alaskan offshore oil and gas development projects.

[7]Stephen Eule and S. Fred Singer, ''Export of Alaskan Oil and Gas, " (New York: Universe Books, 1984), p. 140.

*General Accounting Office, "Issues Facing the Future Use of Alaskan North Slope Natural Gas" (Washington, DC, 1983), pp. 16-19.