Chapter 3

Oil and Gas Production on the North Slope of Alaska

Contents

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INTRODUCTION

The U.S. oil industry and the U.S. Department of the Interior (DOI) contend that unless oil leasing is allowed in the Arctic National Wildlife Refuge (ANWR) and significant quantities of oil are found there, North Slope oil production will soon begin to decline, and that with a decline the United States will become ever more dependent on oil imports.

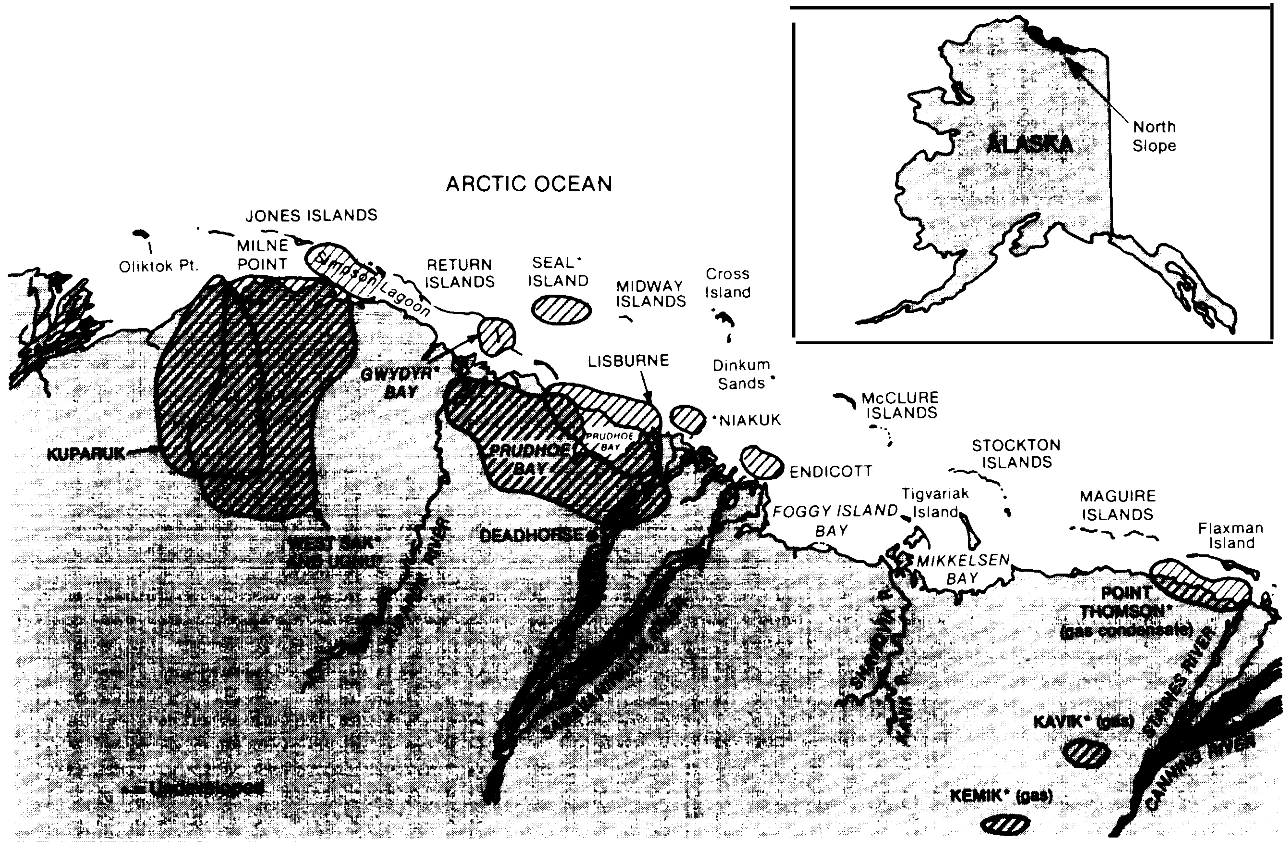
To examine this contention, OTA investigated the status of current production on the North Slope and the potential for additional oilfield development there. In particular, OTA assessed reserves and/or in-place resources in all proven and developed North Slope fields and in known but undeveloped fields where public information is available; assessed what additional production might be expected from these fields in the future as technology improves and/or if additional enhanced oil recovery (EOR) technology is installed; and examined what the contribution to North Slope production from as yet undiscovered onshore and offshore oilfields might be.

Long-term oil production forecasts for the Nonth Slope or, for that matter, for any large area of the United States, are at best gross approximations. Oil forecasts make assumptions about future oil prices, technological developments, environmental requirements, tax and royalty rates, and other variables. Also, forecasts project the success of drilling and other field development activities in areas in which geologic data are often sparse. Finally, forecasts make assumptions about future business strategies, yet company strategies are almost always confidential and, at the same time, subject to change. Consequently, OTA focused its efforts on determining the general production potential of the known fields on the Slope, and on asking the question, "if oil production from the North Slope is not going to decline drastically, where will added production come from?"

We concluded that, although small quantities of additional reserves can be expected from developed, undeveloped, and as yet undiscovered fields on the North Slope, there is no likely source of additional reserves that is large enough to stem a production decline. Thus, North Slope production is likely to begin declining around 1990 – the expected onset of Prudhoe Bay decline–or shortly thereafter. Although the discovery of another Prudhoe Bay-size field in ANWR or elsewhere on the North Slope will help reverse this trend, a field discovered in 1988 would not likely be brought into production before 1998.

As of early 1988, four major oilfields were producing oil in the North Slope of Alaska: Prudhoe Bay, Kuparuk, Lisburne, and Endicott (see Figure 3-l). A fifth field, Milne Point, is developed but not currently producing. In addition to these five oilfields, a number of fields have been discovered but are not yet developed. There are important reasons these other North Slope fields are not yet producing: some may not yet have been sufficiently delineated to determine whether they would be economic to produce; many are too small and/or too far from the Trans Alaska Pipeline System (TAPS) to be economically producible at current market prices; some may have reservoir characteristics that make production difficult and/or prohibitively expensive; and offshore discoveries in more than a few feet of water are currently too expensive to develop and produce. Finally, although many of the best prospects have been tested, only a relatively small portion of the North Slope of Alaska – onshore or offshore – has been explored for hydrocarbons. How much remains to be found is subject to much speculation.

Figure 3-1.—North Slope Oilfields



SOURCE: Office of Technology Assessment, 1988.

OIL PRODUCTION FROM KNOWN FIELDS

Resource Terms

The total amount of oil in known fields on the North Slope is called "in-place" resources. The amount of in-place oil in known fields that has not yet been extracted is considerable, but only a portion of it is currently economically and technically producible. The amount of in-place resources that geological and engineering studies have shown to be recoverable under current economic conditions using existing technology are known as "proved" or "existing" reserves. "Inferred" or "potential" reserves are those resources that should eventually be added to proved reserves through extensions of known fields, through revisions of earlier reserve estimates based on new subsurface and production information, and through production from new producing zones in known fields.[2] The application of new recovery technology (e. g., enhanced oil recovery [EOR] methods) may also result in additional proved reserves. The term "recoverable" resources is less precise but frequently used. The amount specified by the term is sensitive to changing economic conditions and in this study refers to the sum of proved and potential reserves.

Estimates of in-place and recoverable resources can be made using very little data; of course, the more data available, the more accurate the estimates can be (See Box 3-A). Reserves, on the other hand, are based on drilling results and engineering measurements. Estimates of in-place resources in known fields are ideally based on knowledge of the size of the reservoir; porosity of the reservoir rock; reservoir pressure, temperature, and as/oil ratio; and amount of water saturation.[3] Recoverable resource estimates use the same type of information, but in addition they generally require information or assumptions about permeability and oil viscosity, which help reservoir engineers determine the degree to which in-place oil is capable of flowing to a wellhead. Recoverable resource estimates also incorporate assumptions about the expected selling price of oil and the technology used to produce it. Reserve estimates require more extensive resetvoir and producibility information and assume production at current market prices and the use of existing technology.

BOX 3-A
A CAVEAT

Resource estimation is as much art as science, and numerous pitfalls make accurate estimates difficult. Two typical shortcomings of most estimation techniques are limited availability of data and the need to use simplifying assumptions to make estimates. This situation is why most estimates risk input parameters and report probability distributions. Some of the problems encountered in efforts to estimate North Slope resources are considered in more detail in Appendix A. Often, the assumptions –e.g., oil price or state-of-the-art of technology–on which North Slope resource estimates have been based are not specified or are vague. Although OTA considers the data in this report to be the best data currently available to the public, often there was no compelling reason to select one source of information over another. All resource data in this report should be viewed skeptically **and** with knowledge of the limitations of resource estimation techniques.

1. Joseph P. Riva, Jr., World Petroleum Resources and Reserves (Boulder, Colorado: Westview Press, 1983), Chapter 5, "Reserves, Resources, and Reserves/Production Ratios," p. 124.
2. Ibid., p. 126.
3. Ibid.

In-Place Resources of Known Fields

Despite the pitfalls of resource estimation (see Appendix A), the quantity of in-place oil in the developed North Slope fields is reasonably well known from extensive drilling (Table 3-1). Remaining in-place resources in the five developed North Slope fields as of September 1987 are estimated to be about 25 billion barrels. In-place resources of all known North Slope fields may total more than 50 billion barrels. More important is the amount of these in-place resources that is expected to be ultimately recoverable. For the North Slope overall, the recovery efficiency of in-place oil in developed and undeveloped fields is approximately 26 percent.[4] However, recovery efficiencies of individual North Slope fields may vary from O percent to perhaps as high as 50 percent, depending on reservoir and fluid characteristics. Resources in some major undeveloped North Slope fields will not be economic to produce unless oil prices rise substantially and/or unless new, less expensive or more efficient production technologies are developed.

Table 3-1 .—Minimum Remaining In"Place Oil of Major North Slope Fields As of September 1987

	Billion barrels (rounded)
Proven and developed	
Endicott	**1**
Kuparuk River	**4**
Lisburne	**3**
Milne Point	**1**
Prudhoe Bay	**16**
Subtotal	**25**
Discovered but undeveloped	
Point Thomson (gas condensate)	**1**
Seal Island	**1**
Ugnu	**6**
West Sak	**15**
Other North Slope	**2**
Subtotal	**25**
Total	**50**

SOURCES Bureau of Land Management, Anchorage, Alaska, Alaska Department of Natural Resources, Division of 011 and Gas, Institute for Social and Economic Research, University of Alaska

Estimates of in-place resources of known but as yet undeveloped oilfields on the North Slope are more provisional than those for the five developed fields, and estimates for some discoveries may not yet have been released. Undeveloped oil and gas discoveries on the North Slope include the West Sak and Ugnu fields; the Seal Island and Tern Island discoveries; and the Colville Delta, Gwydyr Bay, Niakuk, Umiat, Kavik, Kemik, and Point Thomson fields (Figure 3-l). Only two of these fields are believed to contain significant in-place resources, and even these two are unlikely to contribute significantly to the North Slope production total in the foreseeable future. Many discoveries are either too small or too far from TAPS or both to be economically producible at this time.

The West Sak and Ugnu reservoirs, both of which generally overlie the Kuparuk River reservoir, deserve special attention due to their huge estimated in-place resources. West Sak contains between 15 billion and 25 billion barrels of oil in-place. ARCO has proved the technical feasibility of producing West Sak oil with existing technology, but the reservoir and oil characteristics (e.g., high oil viscosity, low temperature, shallow depth, complex structure) indicate that recovery will be less than 5 percent of the in-place oil if the field is fully developed using current technology. It appears that some production of West Sak may take place if and when oil prices rise (and stabilize) above $20 per barrel. The Ugnu field contains between 6 billion and 11 billion barrels of in-place resources,[5] but the cost and difficulty of recovery of Ugnu oil will be much greater than for West Sak oil. Thermal stimulation through the permafrost probably would be required to produce the very heavy Ugnu oil, but this technique is likely to be impractical and prohibitively expensive on the North Slope for the foreseeable future.

4. **U.S. Department of Energy Energy Information Administration, "Potential Oil Production From the Coastal Plain of the Arctic National Wildlife Refuge," October 1987, p. 18.**

5. **W.W. Barnwell and K.S. Pearson, Alaska's Resource Inventory 1984, Special Report 36 (Fairbanks, AK: State of** Alaska Department of Natural **Resources**, Division of Geological and Geophysical Surveys, 1984), **p. 9.**

Significant gas resources are also found in North Slope fields (Table 3-2). Prudhoe Bay alone contains at least 23 trillion cubic feet of gas considered ultimately recoverable. The distance from U.S. markets and the consequent high cost of building a transportation system for North Slope gas, however, makes it uncompetitive at current gas prices (and at prices corresponding to DOI's oil price scenarios for ANWR development). Neither the proposed Alaska Natural Gas Transportation System nor the competing Trans-Alaska Gas System has secured construction financing or a guaranteed market for the gas it would carry. The Reagan Administration recently determined, however, that North Slope gas could be exported, a finding that may ultimately give a boost to development of North Slope gas, perhaps in the form of Liquefied Natural Gas to Japan. Most of the gas produced at Prudhoe Bay and other North Slope fields is currently reinfected to help maintain reservoir pressure or is used in miscible fluid recovery operations. Some gas is used to operate North Slope facilities. More of this gas may eventually be used on the North Slope to provide the energy required to produce such heavy oilfields as West Sak.

Table 3-2.—Estimated Recoverable Gas in Known North Slope Fields

	Billion cubic feet
Endicott	800
Kuparuk River	600
Lisburne	900
Point Thomson	5,000[a]
Prudhoe Bay	23,000
Total	30,300

[a]No 011 or gas is currently being produced from the Point Thomson field The cost to develop Point Thomson's gas resources would be greater than the cost to develop gas resources in fields already producing 011 Hence, higher gas prices would be needed to develop Point Thomson unless the gas resources were developed in conjunction with the gas condensate and NGLs in the reservoir

SOURCES Alaska Department of Natural Resources, Division of 011 and Gas, Standard Alaska Product Ion Co

Production Constraints

For a number of reasons, oil production on the North Slope of Alaska is more difficult than production in the Lower 48 States. Factors affecting production include the harsh Arctic climate, lack of infrastructure, and great distance from supply sources and markets. The harsh climate of the Arctic is characterized by very low average and absolute temperatures, frequent high winds, and periods of dense fog. Precipitation is low, but snow cover lasts for *8* months or more each year, and blowing snow is common. Low temperatures give rise to permafrost, which may extend 2,000 or more feet below the land surface or seabed, and to sea ice, which can attain average thicknesses of 7 feet or more and persist for as much as 10 months per year in the Beaufort Sea.

Ice affects all aspects of oil activity. On land, the presence of permafrost requires use of special design and construction practices. For instance, well casing must be designed to withstand thaw subsidence stresses that may occur when warm oil flows through the well tubing. Also, all pads and roads must be constructed of gravel about 5 feet thick. Offshore, landfast and moving sea ice, pressure ridges, and other ice phenomena cause problems and added expense for transportation, exploration, and production. All offshore structures must be designed to be able to withstand ice forces.[6]

Lack of infrastructure in the Arctic is another important factor affecting the cost and difficulty of North Slope production. Before Prudhoe Bay was developed, there were no roads, pipelines, or ports on the North Slope and no housing for oilfield workers. Beyond the immediate vicinity of Prudhoe Bay and Kuparuk, this is still the case–for instance, in both the National Petroleum Reserve in Alaska and the Arctic National Wildlife Refuge. Except insofar as development of new fields can take advantage of the infrastructure now in place in the Prudhoe Bay area – more difficult to do as the distance from Prudhoe Bay grows–each new development on the North

6. See **the Office of Technology Assessment's study, Oil and Gas Technologies for the Arctic and Deepwater, Chapter 3, "Technologies for Arctic and Deepwater Areas" (Washington, DC: Government Printing Office, May 1985).**

Slope must be built from scratch. There are no major fabrication **facilities** on the North Slope, so oil production facilities must be prefabricated in the Lower 48 or overseas and barged north during the summer months or trucked overland. Moreover, except for the few Native North Slope Inuit who work for the oil companies, oilfield workers do not live permanently in the Arctic but are shuttled back and forth on a weekiy or bi-weekly basis between the North Slope and locations either in southern Alaska or– less common now–the Lower 48.

Oilfields close to Prudhoe Bay will be able to connect directly to the Trans Alaska Pipeline System; however, as a field's distance from the pipeline terminus at Pump Station #1 increases, the cost of constructing a connecting pipeline increases. Beyond a certain distance, it may not be economically feasible to construct a small-diameter pipeline connecting with TAPS, and other transportation alternatives will need to be considered. The use of ice-strengthened tankers, for instance, has been considered for transporting any oil found beneath the Chukchi Sea, off Alaska's northwestern coast. For producing oil from offshore fields, pipelines must either be buried below the depth of sea ice scour or mounted on expensive and environmentally controversial causeways.

These production constraints – isolation, lack of infrastructure, and harsh climate–are all important reasons why the minimum economic field size (MEFS) required for development increases greatly with increasing distance from Prudhoe Bay. The other significant determinant of the MEFS is the price of oil. The Seal Island discovery is only 12 miles from Prudhoe Bay, but, given its offshore location in 39 feet of water, it is not economic at current market prices– even though its recoverable reserves are estimated to be at least 300 million barrels. The areawide MEFS for onshore ANWR development is estimated by the Department of the Interior to be *440* million barrels, given a market price of $33 per barrel of North Slope oil (1984 dollars) in the year 2000. If oil prices are significantly lower than this in *2000 (e.g.,* at $20 per barrel in 1984 dollars) and costs remain the same, the MEFS for ANWR could easily surpass 1.5 billion barrels, assuming that the calculation of the MEFS for ANWR is correct (OTA has some doubts about this calculation; see Box 3-B on page 104).[7] At distances even further from Prudhoe Bay, in the Chukchi Sea for instance, the MEFS could conceivably be 2 billion barrels or more.

The cost to transport oil from remote North Slope fields to Pump Station #1 and from this point to market is an important factor in determining the MEFS. Total transportation costs averaged about $6 per barrel to transport oil from Pump Station #1 to southern markets in 1987. This oil must travel *800* miles south through the Trans Alaska Pipeline, where it is loaded onto tankers at Valdez and shipped either to the West Coast of the United States or to the U.S. Gulf Coast (after being off-loaded on the Pacific side of the Isthmus of Panama, piped across the Isthmus, and reloaded onto other tankers). If the market price of this delivered North Slope oil is near $17, as it was in January 1988, suppliers would be able to charge $11 at Pump Station #1. The price at the wellhead – given that there is a charge for transporting oil from the wellhead to Pump Station #1 –would be even less. For instance, the Milne Point wellhead price would be $7.70, the Endicott price $9.25, the Kuparuk price $9.61, the prudhoe Bay price $11.00, and the Lisburne price $11.10. For the 6-month period of September 1987 through Februaty 1988, composite wellhead prices for the North Slope decreased from $13.00 to $9.40 per barrel for 27° API crude oil.[8] From per-barrel prices must be subtracted per-barrel capital and operating expenses, taxes, royalties, and the like. Clearly, some of the North Slope producers are operating on a thin profit margin at current market prices. Evidence of this is that the Milne Point field has been shut down since January 1987.

7. **U.S. Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, Final Legislative Environmental Impact Statement, April 1987, p. 79.**

8. **Alaska Department of Natural Resources data reported by the Oil and Gas Journal.**

Reserves and Production

Total oil reserves as of January 1988 from proven and developed fields on the North Slope of Alaska are estimated by the Alaska Department of Natural Resources (DNR), Division of Oil and Gas, to be between 5.25 and 8.22 billion barrels with a mid-range estimate of oil reserves of about 6.5 billion barrels (Table 3-3).[9] This range brackets most other estimates that have been made. Total reserves are sensitive to the price of oil. With low prices, it may not be economical to continue infill drilling beyond a certain point, and the use of EOR techniques may not be economically justified. As prices **rise,** oil companies are able and willing to expend more money to extract additional oil by implementing EOR techniques and by increasing infill drilling.

Table 3-3.—Estimated Remaining Recoverable Oil As of January 1, 1988 **(millions of barrels)**

	Low <$15[1]	Mid $18-$20[2] (1987 $)	High <$24[3]
Proven and developed			
Endicott	270[4]	370	445
Kuparuk River	600	900	1,100
Lisburne	280	380	580
Milne Point	0	60	955
Prudhoe **Bay**	4,100	4,800	6,000
Subtotal	5,250	6,510	8,220
Discovered but undeveloped			
Gwydyr Bay	0	**0**	10
Niakuk	O	55	75
Point Thomson	0	**0**	**350**[6]
Seal Island	0	**0**	**300**
West Sak[7]	0	**500**	1,500
Subtotal	0	555	2,235
Total	**5,250**	**7,065**	**10,455**

[1]All low estimates assume infill drilling will be less than the number of wells forecast for the midrange estimate

[2]All mid. range estimates assume that existing technology is used, that no new enhanced 011 recovery operations are implemented, and that reservoirs perform as expected

[3]Al I estimates assume more In fill than for the mid. range forecast and that additional secondary recovery and/or EOR is implemented and successful

[4]Also assumes waterflood is not successful

[5]Al so assumes Cretaceus sands are developed

[6]Prlmarlly gas condensate This is a natural gas reservoir with 5-trillion cubic feet of recoverable gas and a thin "rim" of underlying crude 011

[7]Also assumes operating agreement signed

SOURCES Alaska Department of Natural Resources, Division of Oil and Gas; West Sak estimate from ARCO Alaska, Inc.. Niakuk estimate based On discussion with Standard Alaska Production Co officials

The difference between the high and low estimates in Table 3-3 is accounted for largely by different assumptions about price, success of EOR operations, and amount of infill drilling likely to be done. The low estimate assumes that oil prices are less than or equal to $15 per barrel (in 1987 dollars) and that infill drilling is less than expected by DNR for the mid-range estimate. The mid-range estimate assumes that oil prices are $18 to $20 per barrel, that existing technology is used, that no **new** enhanced oil recovery operations are implemented, and that reservoirs perform as expected. The high-range estimate might be reached if oil prices rise above $24 per barrel and if additional EOR operations are implemented and successful.

If the high-range price assumption is realized, the Division of Oil and Gas also expects additional oil recovery from discovered but as yet undeveloped North Slope fields, principally the West Sak, Point Thomson, Seal Island, Niakuk, Colville Delta, and Gwydyr Bay fields (Table 3-3). The West Sak field has the potential to contribute the most additional oil from known but undeveloped fields, but there is a wide range of opinion about the amount of oil ultimately recoverable from West Sak. The current ARCO estimate of West Sak's recoverable reserves is much lower than the Division of Oil and Gas estimate.

While there are large amounts of oil in the ground on the North Slope, most of the reserves in producing fields are located in the Prudhoe Bay and Kuparuk River fields. Currently, TAPS is running at just about full capacity with oil from the Prudhoe Bay, Kuparuk River, Lisburne, and Endicott fields. As of spring 1988, the pipeline can carry a maximum of 2.2 million barrels of oil per day, although this capacity could be increased somewhat by installing additional pumps and/or by adding more friction-reducing additives. About 1.55 million barrels per day are produced from Prudhoe Bay, 300,000 from Kuparuk River, 100,000 from Endicott, and about *50,000* from Lisburne, a total of about **2.0** million barrels, comprising roughly 24 percent of the daily U.S. domestic oil supply.

9. William Van Dyke, Alaska Department of Natural Resources, Division of Oil and Gas, personal communication, January 1988.

According to current estimates, North Slope production may begin declining sometime around 1990 (Table 3-4). Some believe this forecast of decline in 1990 is unduly pessimistic, given that estimates of the onset of decline have been revised several times in the past and that the impact of technological improvements cannot be entirely foreseen. Whatever the exact date of the onset of decline, Prudhoe Bay, whose production dominates that of other fields (in 1986 it accounted for 82.8 percent of Alaska's production), is now considered a mature field, and production there must soon begin to slow. Some of the smaller North Slope fields will also begin to decline in the next few years. By 2000, TAPS throughput is expected to be at best 50 percent of current throughput, even with incremental additions from currently planned EOR operations in existing fields and from possible production in several new fields (Figure 3-2). Production could be as low as 25 percent of current throughput by 2000 if low-range reserve estimates prove more accurate.

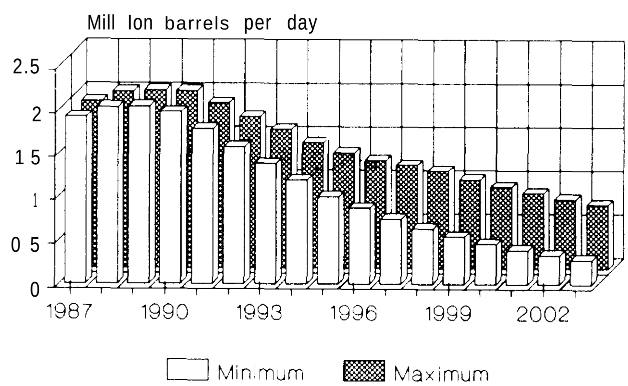
Table 3-4.—Projected TAPS Throughput (thousand barrels per day)

Year	Maximum	Minimum
1987	1,908	1,908
1988	2,024	2,024
1989	2,040	2,030
1990	2,033	1,968
1991	1,891	1,776
1992	1,735	1,565
1993	1,591	1,371
1994	1,430	1,182
1995	1,317	991
1996	1,233	863
1997	1,176	736
1998	1,110	625
1999	1,013	533
2000	931	453
2001	857	385
2002	789	327
2003	726	278
Total	23,804	19,015

SOURCE Alaska Department of Natural Resources, Division of Oil and Gas (19871999), consensus from OTA workshop (2000.2003).

Production forecasts have been made by the Energy Information Administration, the Alaska Department of Natural Resources, the Alaska Department of Revenue, and others. The data presented in Table 3-4 and Figure 3-2 **was** recently compiled by the Alaska Department of Natural Resources, but it is representative of other forecasts as well. Most of the difference between the maximum and minimum North Slope production profiles depends on whether or not Milne Point is restarted and Niakuk, West Sak, Gwydyr Bay, Seal Island, and Colville Delta are developed in the early 1990s. Starting production at these fields depends on the price of oil, but it is impossible to specify the exact price at which each field would be developed. Milne Point–currently shut-in due to low oil prices–may be producing again shortly, and Niakuk is said to be commercial at current oil prices, but the other fields probably will not be developed until the price of oil rises and stabilizes in the area of $24 per barrel. Recent strides incest control could conceivably lower the breakeven price for production from these fields, and recent remarks by ARCO Alaska, Inc. suggest that breakeven prices have indeed come down.[10]

Figure 3-2.-Projected TAPS Throughput Million Barrels Per Day



SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas

10. **ARCO Alaska, Inc., "Security Analyst Meeting," Mar. 30, 1988.** ARCO **notes that "the majority of capital associated with the exploration program and development of exploration successes is viable in the $15 to $25 a barrel range, " p. 29.**

Significant North Slope Oilfields

All oilfields are different, not only in their location, size, structure, and other reservoir characteristics, but also in their response to EOR stimulation, their production profiles, and the recovery expected from each.

Prudhoe Bay

Prudhoe Bay is the largest oilfield in the United States and the 18th largest in the world. It is estimated to have had original recoverable oil of 10 billion to 12 billion barrels. Of this amount, 4 billion to 6 billion barrels remain. The lower figure for Prudhoe Bay's remaining recoverable oil includes oil recovered using primary and currently in-place waterflood and miscible fluid recovery technologies. The higher, more optimistic figure assumes the success of enhanced oil recovery projects that could begin in the future, more infill drilling, and a gradual rise in the price of oil.

Prudhoe Bay oil has a large gas cap and is contained in a high-quality, well managed reservoir, as is reflected by its relatively high estimated recovery factor. Approximately 45 percent of original in-place resources are expected to be recovered. The principal producing formation of the Prudhoe Bay field is the Ivashak Sandstone of the Sadlerochit Group. This sandstone consists primarily of two fine- to medium-grained pebbly sandstone sequences separated by an interval dominated by massive conglomerates. The depth of producing zones is between 8,000 and 9,000 feet.

To stimulate additional recovery at the Prudhoe Bay field, waterflooding (injection of water into the reservoir to drive additional oil to producing wells) began in 1984. With this technique, field operators expect to recover 1 billion more barrels of oil than would otherwise have been possible (included In the above estimate of recoverable oil). In addition, Prudhoe's miscible fluid operation began in December 1986 with the installation of the world's largest natural gas plant. The facility produces miscible injectant (MI–a mixture of natural gas and natural gas liquids; see Technologies for Improved Recovery later in this chapter) from raw plant feed gas stripped from well fluids. The MI is injected into the reservoir with alternate injections of water to stimulate additional oil recovery. The operation also currently produces 50,000 barrels per day of natural gas liquids which are blended into the crude oil stream in TAPS.[11] Remaining residue gas is jected into the reservoir to maintain gas cap pressure. The operators estimate that the project will allow 5 percent additional oil recovery beyond the waterflood operation for that part of the reservoir affected by the EOR project, or an additional 115 million barrels of oil,[12] plus recovery at least 500 million barrels of natural gas liquids (both additions have been included in the above estimate). Also, the facility establishes a large part of the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling projects.[13]

Infill drilling in some portions of the field is continuing at an 80-acre spacing intetval; 40-acre spacing is likely to begin soon[14], which may enable recovery of up to 100 million barrels of additional oil. However, infill drilling is probably more important for maintaining or increasing the production rate of fields than for adding reserves. The total number of wells in the Prudhoe Bay field, when fully developed, is expected to be about 1200. Incremental reserves also might be added by expanding the waterflooding operation and/or by expanding the miscible flooding project. Installation of additional gas handling capability would allow greater short-term production levels–since production is constrained by

11. "World's Biggest Gas Plant Operating on North Slope," Oil and Gas Journal, Jan. 26, 1967, p. 26.

12. Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finance Committee, May 1987, p. A-23.

13. Alaska Department of Oil and Gas, Division of Oil and Gas, Historical and Projected Oil and Gas Consumption, January 1966, p. 6.

14, Optimal spacing of wells is determined by balancing expected recovery with the costs to drill additional wells. On the North Slope, 80-acre spacing is typical. In the Lower 46, 40-acre spacing is standard, but even 5-acre spacing is not uncommon.

the operator's ability to handle gas produced with the oil– but would not significantly change reserves.

The West End/Eileen area of Prudhoe Bay is expected to begin producing in 1988 and will include gas injection facilities for pressure maintenance. There are believed to be about 500 million barrels of oil in place in this area, of which about 150 million barrels are considered recoverable. Production from this portion of the Prudhoe Bay field is expected to peak at 60,000 to 70,000 barrels per day.[15]

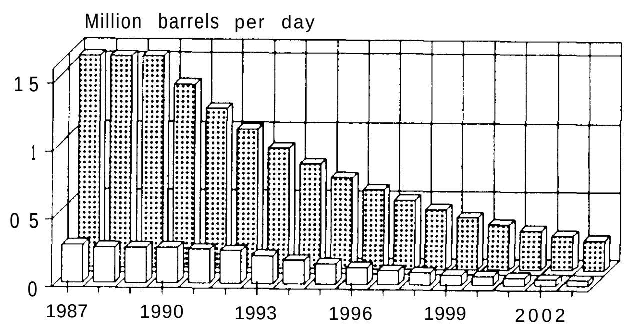
Eventually, more resources also might be recovered in the peripheral area of the Prudhoe Bay field. In the past, operators assumed that production of the Prudhoe oil column was limited to areas where "pay" thicknesses are greater than 100 feet. However, production of the "wedge" zone at the edges of the field using horizontal drilling techniques may yield more oil. This relatively thin zone would not be economic to produce with vertical wells, but horizontal wells allow much more of the formation to be open to the borehole.[16] ARCO notes that development of potential reserves (e.g., Prudhoe Bay's Hurl State and Kuparuk Sand areas, as well as wedge areas) is partially dependent on State severence tax considerations. Under current Alaskan law, oil from marginal fields is taxed at a lower rate than production from more productive fields, thus enabling development of some marginal fields to be economically justified. 17

Industry and government sources now predict that Prudhoe Bay production will begin to decline in late 1989 or sometime in 1990 (initially the decline was expected sometime in 1987) (Figure 3-3). The actual date will depend on the level of infill development drilling, scheduling of well workovers, water and rich gas injection rates, and the capabilities of the installed and to-be-installed gas handling facilities.[18] Pruhoe's gas-oil and water-oil ratios will continue to increase as its oil is produced. When limits on handling gas and water are reached and additional gas and water injection can no longer be done economically, decline will set in. When the Prudhoe Bay field begins to decline, the rate is expected to be about 10 to 12 percent per year.[19] Such a decline rate is typical of most large oilfields that are subjected to pressure maintenance operations.

Kuparuk River

Production of the Kuparuk River field, located about 40 miles west of Prudhoe Bay, commenced in December 1981. Remaining reserves recoverable with primary and existing waterflood technology were estimated to be slightly over 1 billion barrels as of September 1987. Production, which is now between 290,000 and 300,000 barrels of oil per day, second in the United States only to Prodhoe Bay's, is expected to begin a gradual decline to 65,000 barrels per day in 2000

Figure 3-3.-Alaska North Slope Production: Prudhoe Bay and Kuparuk



SOURCES: Alaska Department of Natural Resources, Division of Oil and Gas and Alaska Department of Revenue, November 1987

15. Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finanoe Committee, May 1987, p. A-24.

16. J.H, Littleton, "Sohio Studies Extended-Reach Drilling For Prudhoe Bay," Petroleum Engineer International, Ootober 1985, p. 34.

17. H.P. Foster, Senior Vice President, ARCO Alaska, letter to James Eason, Alaska Department of Natural Resources, Division of Oil and Gas, June 25, 1987.

18. Alaska Department of Oil and Gas, Division of Oil and Gas, Historical and Projected Oil and Gas Consumption, January 1988, p. 6-7

19. "Big Prudhoe Bay Field Passes Halfway Mark at 5 Billion BBL," Oil and Gas Journal, Mar, 30, 1987, p. 40.

(Figure 3-3). Although Kuparuk production is expected to fall off less rapidly than production at Prudhoe Bay, it is only about one-fifth of Prudhoe Bay's production and contributes only about 15 percent of TAPS throughput. Remaining recoverable gas is estimated to be about 525 billion cubic feet.

The Kuparuk River reservoir is not as thick or of as high quality as the Prudhoe Bay reservoir. It has no natural gas cap, and is characterized by faulting and discontinuities. The field covers 400 square miles, of which 200 are currently considered commercially productive. By the end of 1986, 300 wells had been drilled, but at least 700 wells will be required for full field development. Constant infill drilling will be necessary to retard decline as long as possible and to tap areas separated by faults.

ARCO Alaska, the operator, is expanding the waterflood program and has recently begun a pilot miscible gas injection project to boost ultimate recovery from the reservoir. A third central production facility was added in 1986, with a reserve addition of 170 million barrels of oil.[20] A small gas plant in the field currently produces about 3,700 barrels per day of natural gas liquids that are blended with the oil and sold.

Lisburne

The Lisburne reservoir lies within the Prudhoe Bay Unit but is about 1,000 feet deeper than Prudhoe Bay's main reservoir in the Ivishak formation. Lisburne and Prudhoe Bay were discovered by the same well. Production from this third largest North Slope field (in terms of estimated reserves) began in December 1986. Thus far, production at the Lisburne reservoir has not been as good as hoped. Lisburne is a naturally fractured carbonate reservoir, less porous than the Sadlerochit main producing formation at Prudhoe Bay. Lisburne's fractured nature has presented some technical production problems. Moreover, at least parts of the formation contain hydrogen sulfide gas which is both corrosive and poisonous.[21] Although the Lisburne field originally had about 3 billion barrels of oil in place, only between 7 percent and 22 percent of in-place resources are expected to be recovered from primary production and with EOR operations planned or in place. The small size of the Lisburne field compared to Prudhoe Bay, as well as lower per well production rates, faster decline in individual well production rates, greater costs associated with greater drilling depths, more difficult rock to drill, presence of hydrogen sulfide gas, etc., make Lisburne somewhat of a marginal North Slope field at current market prices.

Recoverable resources as of January 1988 were estimated by DNR to be between 280 million and 580 million barrels, but operators have noted that, due to the fracturing, it is very difficult to estimate reserves accurately in the Lisburne field without substantial additional drilling. Reserves of this size would be considered substantial in the Lower 48; however, on the North Slope, Lisburne is only marginally economic. Lisburne's early development was helped by its proximity to TAPS and to the infrastructure already in place at Prudhoe Bay. If current lower oil prices had been anticipated, Lisburne might not have been developed when it was. A similar size and type of field 100 miles from the pipeline probably would not be economic to develop at the present time.

Lisburne production was initially expected to peak in the mid-1990s at between 80,000 and 100,000 barrels per day. A revised estimate, which takes into account the difficulties in producing Lisburne, calls for peak production of only 50,000 to 60,000 barrels per day (Figure 3-4).[22] Production of between 45,000 and 60,000 barrels per day is expected to continue through the mid-1990s.

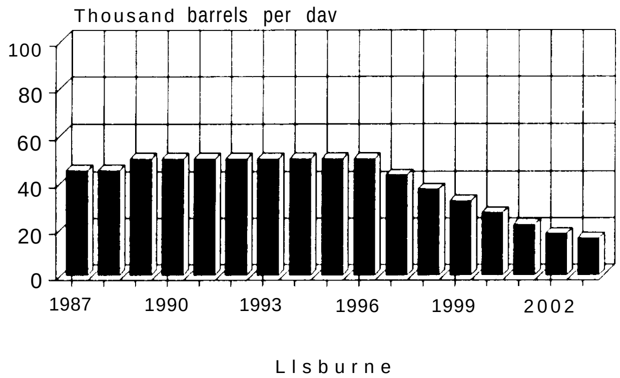
The Lisburne field includes both onshore and offshore areas. Proposed offshore site construction, however, has been canceled. Most of the offshore oil in the Lisburne field can be reached by directional drilling from shore, and ARCO

20. ARCO, Oil Industry Analysts Meeting, New York City, March 31, 1987, p. 13.

21. M. Harris, "Marginal Fields: Minimizing the Risk, " Alaska Construction and Oil, July 1985, p. 15.

22. Alaska Oil and Gas Conservation Commission, personal communication, December 1987.

Figure 3-4.-Alaska North Slope Production: Lisburne



SOURCES: Alaska Department of Natural Resources, Dwision of Oil and Gas, November 1987; ARCO Alaska, May 1988

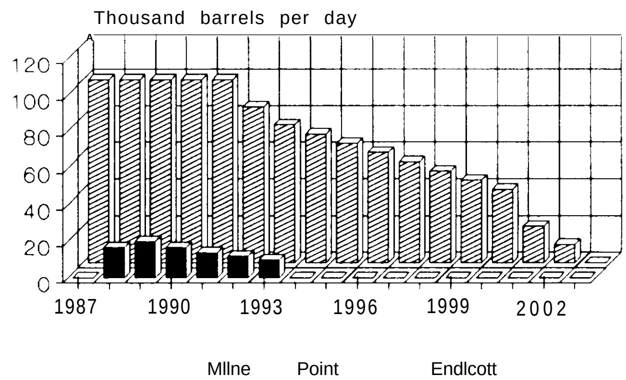
believes it can get to the top of the gas cap–the optimum location for reinfecting gas– by drilling wells with large horizontal offsets from shore. Directional drilling is not expected to reduce oil recovery. A separate geologic structure offshore (the Kuparuk River sand play, productive in the Kuparuk River oilfield and at Niakuk) with an estimated 20 million barrels of reserves is accessible only from an offshore site.[23] Alternatives to exploit this reservoir will have to be developed now that the offshore Lisburne drill site has been canceled. Ultimate recovery at Lisburne is expected to increase if a pilot waterflood project now underway proves to be successful. A small gas plant in the field currently produces about 2,600 barrels per day of natural gas liquids (NGLs), which are blended with the oil and sold.

Endicott

The Endicott field, which began oil production in October 1987, is the North Slope's newest developed field. It is distinctive in that it is the North Slope's first offshore producing field. Located about 15 miles from Prudhoe Bay and about 2 miles offshore in State waters 8 to 10 feet deep, the Endicott field is believed to have about 375 million barrels of oil resewes and 800 billion cubic feet of recoverable gas. Approximately 35 percent of its in-place oil resources are expected to be recovered. Production is from the Kekiktuk conglomerate formation of Mississippian age and takes **place** from an artificial 45-acre main production island and a 10-acre satellite island. A gravel causeway connects both islands with the shore and provides pipeline and road access.

The Endicott reservoir is similar to Prudhoe Bay's in that it consists of good quality sandstone-conglomerate and contains a large gas cap. The main producing zone has better quality rock than does Prudhoe Bay. The continuity and quality of a second producing zone are still being studied. A significant amount of gas will be produced with Endicott's oil; hence, lack of sufficient gas handling capability could constrain oil production. Production peaked **at 115,000** barrels per day in early 1988– equivalent to 5 percent of maximum daily TAPS throughput–and is expected to remain at this level until the field begins to decline, estimated to be some-

Figure 3-5.-Alaska North Slope Production: Endicott and Milne Point



SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas, November 1987

23. "Arco Eyes Production Start at Lisburne During Me 1986," Oil and Gas Journal, August 5, 1985, p. 85.

time in 1992 (Figure 3-5). About 2,500 barrels per day of NGLs are produced at Endicott.

Endicott is also of interest because its development is economic only as a result of intensive efforts to trim the high costs of Arctic construction and drilling.[24] Fields like Endicott are likely far more common on the North Slope than Prudhoe Bay-size fields, and close attention will have to be paid to keeping development costs down. Endicott developers were able to build upon experience gained at Prudhoe Bay for example, operators found that retrofitting is very expensive. Thus, primary and secondary recovery capabilities have been part of the production facilities at Endicott from the outset. Hence, waterflood, low pressure separation, gas reinjection, and gas lift can begin at Endicott without substantial additional capital expenditures.

Milne Point

With approximately 60 million barrels of reserves, Milne Point is the smallest of the developed North Slope fields. Production is from the Kuparuk River formation, an extensively faulted sandstone. Milne Point is about 35 miles northwest of Prudhoe Bay. Like Lisburne and Endicott, the proximity of the Trans Alaska Pipeline has spurred development; however, the amount of oil that Milne Point can contribute to TAPS is relatively insignificant. The production target for

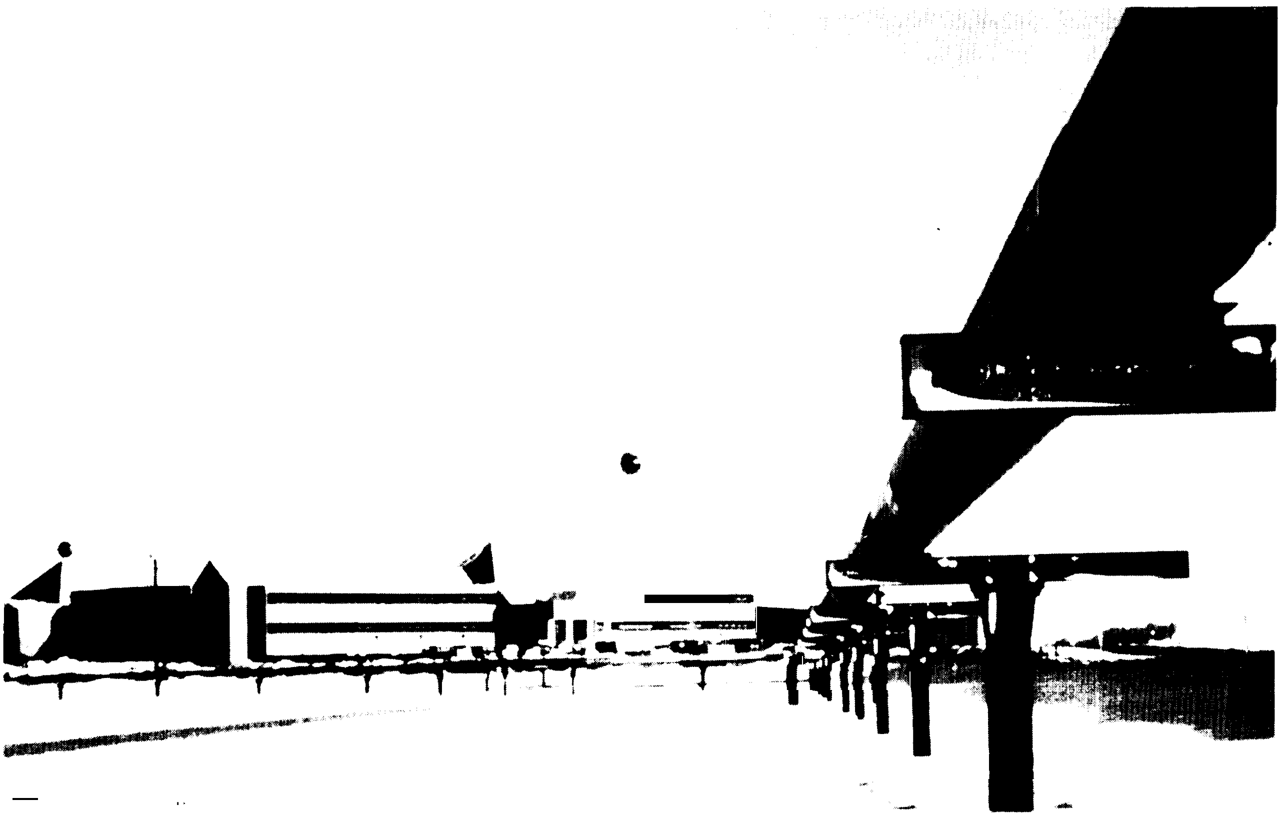


Photo credit *American Petroleum Institute*

Production facilities at Milne Point. **The field is now shut in.**

24. Ml. Curtis and D.B. Huxley, "first Arctic Offshore field, Endicott, On Decade-Long Way to Production," Oil and Gas Journal, June 24, 1985, p. 64.

the resewoir is 30,000 barrels per day. If this target is reached, Milne Point will account for 1.5 percent of TAPS throughput during its peak production period. Currently, the peak production capacity is 15,000 barrels per day, or only half the production target (Figure 3-5). Waterflooding has been used since inception, but additional waterflooding and other conventional engineering will be required to produce all of the field's estimated reserves.

Milne Point is the only North Slope field to date that has been shut down due to low oil prices. The field was shut down in January 1987 after a little more than one year in operation. However, it is being maintained in a "warm shutdown" mode so operations can resume quickly if oil prices rise. Conoco, the operator, believes that Milne Point can be economically viable at an oil price of $22 to $25 per barrel .25

Milne Point has both onshore and submerged tracts. In addition to the 60 million barrel reserve within the Kuparuk River formation, additional oil may be recoverable using tertiary recovery techniques from the field's shallower Cretaceus sands (identical to the West Sak sands in Kuparuk). However, these shallow sands are loosely cemented and contain viscous oil. Techniques have not yet been worked out to allow the operator to maintain economic flow rates. Closer well spacing will be needed, so the cost of developing these sands will be higher than the cost to develop the main portion of the field.[26]

Proven But Undeveloped Fields

The Alaska Department of Natural Resources has estimated potential reserves for five proven but undeveloped North Slope fields: West Sak, Point Thomson/Flaxman Island, Seal Island/Northstar, Niakuk, and Gwydyr Bay. DNR estimates that production of some West Sak oil might begin at oil prices somewhat below $24 per barrel, but DNR estimates that oil prices will have to rise to at least $24 per barrel before the other three fields will be profitable to develop. Technical innovation may be required in some fields as well.

West Sak, with estimated in-place resources of roughly 15 to 25 billion barrels, is potentially the most important of these fields. Between 2 and 5 percent of these resources are considered recoverable. Approximately 0.5 billion barrels are likely to be recoverable using technology developed from the West Sak pilot project, and 1.5 billion barrels may be recoverable with higher oil prices and using advanced EOR techniques.[27] However, both the amount of oil in place and the ultimate production potential of this marginal field are highly uncertain .28 Ultimate production potential may be higher than currently estimated. The West Sak field is at a shallow depth, close to an overlying 1,800-foot-thick layer of permafrost, **and has a reservoir temperature of about** 70°F compared to 195°F for the deeper pay zones in the Prudhoe Bay field. Temperature affects viscosity and the lower temperature West Sak oil is a thick, molasses-like, low-grade crude, which makes it much more difficult to produce than the higher quality, higher temperature oil in the Prudhoe Bay and Endicott reservoirs. The West Sak reservoir is composed of unconsolidated fine-grained sand that tends to flow into the well bore when higher flow rates are attempted.[29] Structurally, West Sak is fairiy complex, consisting of multiple faults and "finger" sands. There is large variability in pay zones and fluid properties across the fieid.

The only long-term production tests to date in West Sak have been in conjunction with a 2-year pilot project. In all, 14 pilot production and injection wells were drilled to a depth of 4,000 feet. Water for the injection wells was heated and injected under high pressure into the formation to increase the temperature of the oil. The flow rate for the test wells was only about 1 percent of the

25. M. Harris, "Oil Industry in Transition," Alaska Construction and Oil, p. 12.

26. Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finance Committee, May 1987, p. A-24.

27, R.K. Doughty, ARCO Oil and Gas Company, letter to OTA, Jan. 14, 1988.

28. Berman et al., op. cit., footnote 26.

29. M. Harris, "Marginal Fields: Minimizing the Risk," Alaska Construction and Oil, July 1985, p. 21.

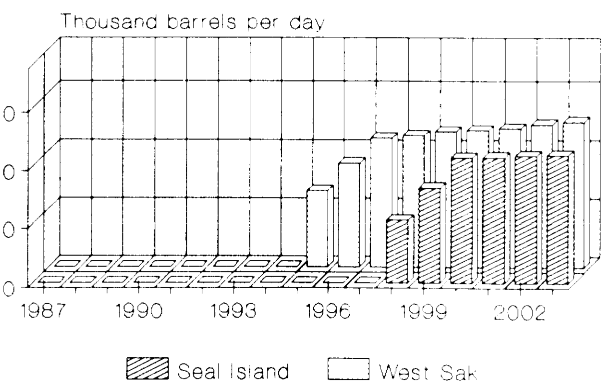
rate for Prudhoe Bay's initial wells–about 200 barrels per day versus up to 20,000 barrels per day at Prudhoe (Prudhoe Bay production averages about 6,000 bpd per well). Because of the reservoir rock and fluid properties, many more wells are likely to be needed than is the case for Prudhoe Bay. Also, the shallow depth of the West Sak reservoir implies that more well pads will be needed than at Prudhoe or Kuparuk since the same horizontal drilling offsets will be difficult to achieve. West Sak acreage drained per well pad will be substantially less (assuming the same number of wells per pad and similar drilling angles and "kickoff" points, a Prudhoe Bay pad would be able to drain 12 times the area as one in West Sak). Thus, a West Sak field would take a long time to develop, and without a breakthrough in recovery technology, is not expected to contribute much to keeping TAPS full. One development scenario envisions five production centers with a total of 5,100 wells (about five times the number of development wells in the Prudhoe Bay field).

In 1984, ARCO estimated that the West Sak field could be in full production by the late 1980s; however, the company suspended work on the West Sak pilot project in December 1986. ARCO is still evaluating the pilot project results and conducting research on how to develop the field economically. If economic conditions are right, the field could produce about 100,000 barrels of oil per day by 2000 and account for approximately 5 percent of current TAPS capacity. ARCO has shown that the field can be producti using existing technology. However, sophisticated enhanced recovery systems would be required, and these are justifiable only with high oil prices and stable economic conditions.[30] One advantage for West Sak development is that it should be able to capitalize on the extensive facilities already in place for the Kuparuk field; however, full development of West Sak will require the same enclosed production and personnel facilities as Prudhoe Bay but with far less revenue-production potential per dollar invested.[31]

ARCO remains hopeful that it can achieve breakthrough in recovery technology. It plans on beginning a new experimental drilling program in 1989, with up to 25 wells in the pilot program if early wells are successful.[32] If the program is fully successful, ARCO hopes eventually to produce 200,000 to 300,000 bbl/day from the field.[33] Given the substantial technical problems remaining, however, the prospects for West Sak are highly uncertain. Figure II I-6 presents a projection of future West Sak production assuming use of available technology.

The Seal Island/Northstar field, being explored by Shell, Amerada Hess, and partners, may be the second offshore field developed. Located approximately 12 miles northwest of Prudhoe Bay, the Seal Island/Northstar field is partially in Alaskan State waters and partially in waters disputed between Alaska and the Federal Government. The disputed leases are managed by the Federal Government. The field is estimated to have in-place resources of approximately *900* million barrels and potential reserves of about

Figure 3-6.-Alaska North Slope Production: West Sak and Seal Island



SOURCE: Alaska Department of Revenue, September 1987.

30. M. Harris, "Oil Industry in Transition: Alaska Activity on the Rebound," Alaska Construction and Oil, October 1987, p. 11.

31. M. Harris, "Marginal Fields: Minimizing the Risk," Alaska Construction and Oil, July 1985, p. 21

32. T. Bradner, "ARCO Plans West Sak Development," The Energy Daily, December 7, 1988; and personal communication, James Posey, ARCO Alaska, December 12, 1988.

33. Ibid. This rate of production would be sustained only for a short period, unlike the longer production plateau at Prudhoe. Personal communication, James Mitchell, ARCO Oil and Gas Co., Piano, Texas, December 12, 1988.

300 million barrels. Thus, the field appears to have about the minimum volume of recoverable oil necessary for economic production in the Beaufort Sea given $24 per barrel oil.[34] Seal Island will be considerably more expensive to develop than the Endicott field because it is located 6 miles offshore *(4* miles further offshore than Endicott), in 39 feet of water (3o feet deeper than Endicott), and in a floating fast ice zone where moving ice can be a hazard during storms and "breakup." Given the long lead times required for development in the Arctic offshore, production is not expected to begin before the mid-1990s even if prices bounce back up. Higher oil prices and the expectation of continued higher prices will be required to start development and production from the Seal Island and Northstar discoveries. If developed, production could reach *45,000* barrels per day (Figure 3-6) or more. To date, four exploration wells have been drilled on Seal Island and another two on Northstar Island, which is 5 miles west of Seal.

Furthur offshore, Shell and partners announced discovery of oil in early 1986 in the Harvard prospect. The discovery was made from the manmade Sandpiper Island in 49 feet of water. The Haward prospect is geographically close to Seal and Northstar, and, if enough recoverable oil is present, could be developed concurrently. The Minerals Management Service has termed the find "producible," by which it means there is at least enough oil present to cover daily operating costs of production. The most difficult problem in developing the Seal/Northstar/-Sandpiper area will be constructing the pipeline to shore. Either a buried pipeline or a 5-mile piling-mounted pipeline will be needed, both of which will be very expensive.

The Point Thomson/Flaxman Island field, located on the coast of the Beaufort Sea east of Prudhoe Bay, is estimated to contain about 350 million barrels of recoverable condensate (light gravity hydrocarbons) and approximately 6 trillion cubic feet of recoverable gas. However, development not only awaits higher oil prices but is based on the assumption that a gas cycling project will work that will enable recovery of gas liquids without having to transport and sell the field's gas resources, which is not now economically feasible.[35] The development potential of the Point Thomson field also suffers from its location about 60 miles from the Trans Alaska Pipeline. The outlook for development of this field could improve if a significant oil discovery is made in the Arctic National Wildlife Refuge immediately to the east and a pipeline is built that could also sewe Point Thomson.

In December 1987, the Standard Alaska Production Company declared the Niakuk field, located in *4* feet of water 1 mile offshore in State waters immediately northeast of Prudhoe Bay, to be commercial. Standard has estimated reserves to be about 55 million barrels of oil, recoverable using primary and waterflood techniques, and thus the field appears to be in a class with Milne Point and other marginal North Slope fields[36] The reservoir is the Sag River sandstone! productive at Prudhoe Bay, and separated from Prudhoe by the Niakuk fault system. The field is heavily faulted and divided into at least three discrete pieces, two of which are considered by Standard to be commercial at current oil prices. Standard would like to start producing Niakuk in 1991, contending that this field will be economic to produce, despite its small size, because the field is quite close to Prudhoe Bay, will not require a long offshore causeway or onshore connecting road, will likely be able to use spare production capacity at the Prudhoe Bay and Lisburne fields by the time production begins, and, given its small size, will not require special engineering but will be able to use off-the-shelf facilities. Standard hopes that the field can contribute *20,000* barrels of oil per day to TAPS by the end of 1991.[37]

DNR has estimated potential reserves in the Gwydyr Bay field northeast of Prudhoe Bay–assuming a minimum oil price of $24– of 10 million

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34. Alaska Department of Natural Resources, Division of Oil and Gas, 1987,
35. Berman et al., op. cit., footnote 26.
36. "Alaska Work Hikes Standard Reserves; Niakuk Commercial," Oil and Gas Journal, Dec. 21, 1987. p, 17.
37. T. Obeney, Niakuk Field Manager, Standard Alaska Production Company, telephone conversation, Jan. 28, 1988.

barrels. Potential resewes of other small oil discoveries – including Tern Island 35 miles east of Prudhoe Bay, Colville Delta west of the Kuparuk field, Umiat in the National Petroleum Reserve in Alaska (N PRA), and the Hammerhead and Phoenix prospects–and of gas discoveries such as the Kavik and Kemik fields immediately west of ANWR and the East Umiat and Gubik fields in the NPRA have either not yet been determined or not released. There is little to suggest that any of these fields will ever contribute more than small incremental amounts to total North Slope production. Many may never be developed.

TECHNOLOGIES FOR IMPROVED RECOVERY

As discussed above, the four largest producing North Slope fields– Prudhoe, Kuparuk, Lisburne, and Endicott– make up all of the present TAPS production and will continue to dominate with at least 80 to 90 percent of ail North Slope production well into the 1990s, even with the most optimistic assumption of development for other known fieids. With this background, OTA investigated the potentiai of new advanced recovery technologies either to improve production forecasts for these four fieids or to improve production opportunities for other known, but not yet producing, North Slope fields.

To begin this investigation, OTA evaluated future Alaskan North Slope oil production projections and the technological assumptions that affect them. Next, OTA held a workshop[38] to identify current technologies and to project the development of new technologies that could improve production from known Alaskan oilfields. In preparation for the workshop, OTA extracted from pubiished data oil production projections with their accompanying assumptions and assembled brief descriptions of field characteristics. The workshop was focused on the identification of technologies (and their stages of development) that may be used in these fieids. OTA asked the workshop participants to review and critique the data assembled and to suggest and discuss technologies from their own knowledge and experience. Participants in the workshop included industry experts in enhanced oil recovery and in North Slope reservoir engineering, as well as researchers from the University of Houston and private independent firms.

The findings of the workshop covered three principal topics: field characteristics that limit recovery; technologies to improve recovery; and projections of future North Siope oil production.

Prudhoe Bay is now and has aiways been the premier oiifield on the Alaskan North Siope. Not only is it the largest field in the United States, but it is seven to eight times as large (in reserves) as Kuparuk, which ranks number two. Prudhoe is a field with high recovery potential, now estimated at 42 to 45 percent of original oil in place. Prudhoe is the fieid whose potential fired all North Slope development over a decade ago, and its production is still more than 80 percent of ail North Slope oil. Prudhoe is a mature field and is near its peak production.

The other three producing North Slope fields– Kuparuk, Lisburne, and Endicott– now contribute about 15, 2, and 5 percent, respectively, to total North Slope production. The other known North Slope fields– both onshore and offshore– are considered to be of minor importance either because of size (e.g., insignificant portion of TAPS throughput) or because present economics prohibit their development. OTA workshop participants reviewed the information on these other fields and selected one (West Sak) out of the group for discussion. West Sak is a very large field that is not presently economical and that would require significant implementation of enhanced recovery techniques to produce oil. It represents a field with potential but with a range of significant barriers (technical problems) to overcome to reach its potential. The workshop participants therefore focused on technologies that would be applicable to five known North Slope fields –four now producing and one potential.

The oil well recovery systems that are used today are typically described as either primary, secondary, or tertiary. Primary recovery produces the fraction of in-place oil that will flow unaided or can be pumped from the reservoir rock matrix to the surface. Depending on the reservoir characteristics, from 5 to 80 percent of in-place oil may be recovered using primary recovery techniques. In the United States as a whole, average primary recovery has been about 28 percent of in-place oil.[39] In 1979, the American Petroleum institute reported that the average ultimate recovery of U.S. oil is about 32 percent, with a low of about 14 percent in Ohio and a high

38. “North Slope Enhanced Oil Recovery Technologies”, Dec. 8, 1987, University of Houston, Houston, Texas.
39. Todd M. Doscher, “Enhanoed Recovery of Crude Oil,” American Scientist, April 1981, p. 195.

of about 65 percent in east Texas. The large, highly permeable reservoirs of east Texas and southern Louisiana have a history of high primary production. Prudhoe Bay is this type of reservoir.

Secondary recovey techniques are in common use in many reservoirs to increase the percentage of oil recovered. These methods attempt to maintain or restore reservoir pressure by the injection of gas or water (waterflooding). Depending on reservoir conditions and oil properties, secondary recovery techniques can improve in-place oil recovery to between 30 and 50 percent. The injection of water into a reservoir to displace the in-place oil, to reproduce a natural water drive, is the basic secondary recovery operation. In the United States as a whole, waterflooding raises oil recovery efficiency by a factor of 1.5 to 2.0. Waterflooding is dominant among fluid injection methods, and its widespread use is due to the easy availability of water, the relative ease of injection, and the efficiency with which water spreads through a reservoir and displaces oil.

Prudhoe Bay and Kuparuk fields have secondary recovery waterflood operations in place; Endicott is scheduled to start waterflood in 1989 and Lisburne has a waterflood pilot operating. All producing North Slope fields now have applicable secondary recovery techniques in place or planned.

After secondary recovery methods are exhausted, the extraction of additional oil from fields requires the application of more sophisticated and expensive techniques. Enhanced oil recovery processes (or tertiary techniques) can further increase recovery to 40 to 80 percent of the original in-place oil, depending upon the process employed and upon the physical properties of the reservoir and the oil. These techniques usually attempt to reduce oil viscosity and/or to affect other characteristics that impede oil flow. The techniques work by introducing to the producing formation either heat (steam) or substances such as rich miscible gas, carbon dioxide, polymers, solvents, surfactants, micellar fluids, or even microorganisms in various combinations, depending upon reservoir conditions and crude oil properties.

One of these techniques (rich miscible gas injection) is now in place with a major project at Prudhoe Bay and another at Kuparuk. The OTA workshop focused attention on whether a range of enhanced recovery techniques might be applied to the four producing fields and West Sak and, under the most optimistic economic conditions, what improvements in ultimate recove~ might be expected.

The OTA workshop reviewed each of the five fields under consideration and noted key features as well as constraints to further production as follows:

Prudhoe Bay (42 to 45 percent recovery)

- Largest light oilfield (27°API, 190°F)
- Dominant and most mature field
- Nearest to decline (1989 or 1990)
- Projects now in place to enhance recovey include:
  - Waterflood
  - Miscible gas injection
  - Infill wells*
  - Horizontal drilling*
  - Other studies by the operators to enhance future recovery include:
  - Adding more natural gas liquids to TAPS
  - Expanding gas handling to increase miscible gas injection
- Reservoir is a thick, high-quality sand with **a** big gas cap
  - Barriers to increased recovery are limited waterflood contact with oil in the reservoir and gas handling capacity

*These techniques are used primarily to accelerate production rather than to increase ultimate recovery, although some increases are possible, for example, when horizontal drilling is used to reach areas of thin pay not easily drained by regular wells or when infill wells drain portions of oil reservoirs that are not in close connection to the primary network of wells.

Kuparuk (25 to 30 percent recovery)

- Second largest field (27 °API, 150°F)
- Compared to Prudhoe, formation is thinner and more spread out with more faults and no gas cap

- The field is constantly on decline without continual infill drilling
- Of *400* square miles, only the inner 200 square miles is commercial
- Waterflood and miscible gas injection projects are now in place
- Barriers to improved recovery include oil saturation, faulting, and relatively thin pay

Lisburne (7 to 22 percent recovery)

- About one-half of this reservoir underlies the main reservoir of the Prudhoe Bay field (27°API, 190°F)
- Very difficult field to produce
- Carbonate reservoir, not well described
- How well oil can be recovered from complex matrix is not yet known; more drilling is needed to better define the reservoir.
- Small waterflood pilot is being tested
- Barriers to improved recovery include low porosity and permeability; fracturing

Endicott (35 percent recovery)

- Similar to Prudhoe reservoir with big gas cap (23°API, 210°F)
- Waterflood designed into the beginning of project for 1989 start-up
- Gas handling may be future problem
- Small field compared to Prudhoe production
- Constrained by faults; reservoir volume well-defined

West Sak (15 to 25 billion barrels estimated oil in place)

- Largest medium-heavy oilfield on North Slope (14 to 22°API, 70°F average)
- Recovery rates are now estimated between O and 5 percent by industry, depending on section of the field
- Very difficult field to produce because of poor reservoir conditions, i.e., unconsolidated fine sand and viscous, low-temperature oil
- Early tests indicate well production rates will be very low (hundreds of barrels per day), requiring thousands of wells for any substantial production
- Industry concludes the field is not producible at today's prices

Enhanced recovery techniques possibly applicable to North Slope fields are in three categories: miscible flooding, chemical flooding, and thermal techniques.

Miscible flooding is a technique based upon using some gas– such as enriched reservoir gas (as at Prudhoe) or carbon dioxide (COQ) or another gas–to miscibly displace some oils, thereby permitting the recovery of most of the in-place oil contacted. The miscible gas is injected into the formation at an injection well and forced toward a production well. A technique for forcing and directing the miscible gas is to alternate water slugs through the same injection well. This is known as Water-Alternating Gas (WAG). A further improvement can be achieved by adding a detergent to the water in WAG which then forms a foam and reduces the apparent viscosity of the fluid. COQ gas is more commonly used in the Lower 48 because reservoir gas is a more valuable product. At Prudhoe Bay, gas is not currently marketable and therefore is a more attractive flooding agent.

Chemical flooding is a technique based on adding various chemicals to the water used in waterflooding in order to increase waterflood efficiencies. Chemicals may be polymers, which increase the viscosity of water, surfactants to help release immobilized oil, strong alkalines which themselves form surfactants, or other more complex substances. Foaming agents also have been added to chemical flooding to create a more efficient solution.

Thermal methods involve the injection of steam or hot gas or in-situ combustion – all for production of heavy crude oils whose recovery is impeded by viscous resistance to flow at reservoir temperatures. Foaming agents also can be added to steam to increase steam injection efficiency.

Pressure cycling is the technique of injecting natural gas or COQ into the producing formation and alternating high and low injection pressures to induce mixing with the crude and thus stimulating the flow. Lab testing and simulations of "pressure cycling" have been done, and it is believed to be a promising technique for highly fractured rese~oirs (such as Lisburne).

Some of these techniques have already been applied (rich miscible gas injection at Prudhoe and Kuparuk) and others have been studied. The list in Table 3-5 covers most of those considered possibly viable by the industry and other researchers at this time. The technique that has provided major improvements for North Slope fields (beyond secondary waterflood) is miscible gas injection. Most others are considered experimental at this stage and almost all must be field tested. A common feature of EOR development is that it is difficult or sometimes impossible to accurately scale up the results of laboratory tests to the field level. Also, some technologies appear impractical for certain North Slope conditions. For example, many thermal processes are difficult to apply because of wide well spacing, depth of the reservoirs, and the substantial permafrost layer.

None of the techniques appear to offer a major increase in recovery rates for the existing North Slope fields. Rather, the dominant industry view is that continued enhanced recovery efforts over a long period of time would likely be able to add a series of small increments to the ultimate recovery percentage for any given field. In general, the industry appears to have greater faith in the gradual accretion of experience from application of existing recovery methods than in the potential of exotic new methods. For Prudhoe Bay this may mean that about 10 percent more oil ultimately will be recovered. For other fields, application of EOR techniques might push recovery rates to the high end of ranges now estimated. In any case, it is not likely that the onset of decline in North Slope production can be delayed more than a few years. The most likely outcome of using more enhanced recovery technology would be to extend field life. This outcome would increase total recovery from certain fields but not necessarily have any immediate effect upon short-term production rates.

Table 3-5.—Some Enhanced Recovery Techniques Possibly Applicable to North Slope Fields

M/se/b/e flooding	Injecting CO_2[1]
	Injecting Rich Gas[2]
	Water-Alternating-Gas (WAG) to control injectant[2]
	Foam to improve WAG effectiveness[3]
Chemical flooding	Using—Surfactant Polymers[1]
	—Polymers[1]
	—Alkali[3]
	—Foams to enhance other chemicals[3]
Themal *methods:*	Steam Injection[1]
	In-Situ Combustion[3]
	Hot Gas Cycling[4]
	Foam (Steam + Surfactant + Inert Gas)[3]
Pressure cycling	Using natural gas or CO_2[4]

NOTES 1 In use II other-Lower 48-fields
2 In use— North Slope
3 Some pilot tests
4 Lab tests and experiments

SOURCE Off Ice of Technology Assessment, based on Dec. 8, 1987 workshop

Application of EOR technology is *a/ways* **a** decision based on economics. Those techniques which the industry considers to be economic under current conditions are being applied in North Slope reservoirs. Higher crude oil prices could result in wider application of current techniques and also increase the chances for economic application of other more speculative technologies.

Table 3-6 shows, for four North Slope fields of interest, the factors for each which may limit production and some applicable enhanced recovery techniques. "Present EOR" denotes work already in place; category A covers techniques that may be applied depending on economic conditions and individual company plans. Category B includes speculative techniques which require development and/or testing and higher oil prices.

Summary

Most of the enhanced recovery techniques that seem practical for North Slope fields today are either in place or already planned for installation in the future. OTA's review did not uncover any technologies that offered major improvements in recovery rates from the fields where we had available information. A careful examination of advanced technologies at the University of Houston workshop led to the summary of possible future enhancements discussed above. The conventional approaches cover most of those in use or planned. More speculative technologies have promise for the future but would certainly require further field testing. OTA was not able to evaluate the economics of EOR but notes that industry claims oil prices must increase before any

Table 3-6.—Problems Limiting North Slope Recovery and Technologies Which May Improve Recovery

Prudhoe Bay	
Limits: Residual Oil Saturation to Waterflood	
Actual High Recovery at 42-45%	
(A good performer as Is)	
Present EOR: Waterflood; Miscible Gas Injection;	
Infill and Horizontal Drilling	
A) Conventional Technologies:	Expansion of Waterflood
	More Miscible Gas
	Expand Gas Handling Capability (Gas Cycling)
	More Infill Drilling
B) Speculate Technologies:	Foam to Improve Miscible Gas (Mlscible Flood)
	Surfactant/Polymer (Chemical Flood)
West Sak	
Limits: Unconsolidated Fine Grained/Sand Production	
Viscous Oil	
Poor Rock Quality (shaly)	
A) Conventional Technologies:	Waterflood
(not econom!c today)	Fracturing
B) Speculative Technologies:	Thermal Methods
	Miscible Gas or CO, (Miscible Flood)
Kuparuk	
Llmds Basic Residual 011 Saturation Problem	
Faulted	
Thin Pay–Especially Outer Edges (half of field area)	
Absence of a gas cap not a problem since much gas nearby	
A) Conventional Technologies:	Waterflood
	Miscible Gas
	Infill Drilling
B) Speculative Technologies:	Foam to Improve Miscible Gas (Miscible Flood)
	Polymer (Chemical Flood)
	Micellar Polymer (Chemtcal Flood)
Lisburne	
Limits Fractured Limestone	
Low Porosity/Permeability	
A) Conventional Technologies:	Waterflood (may be difficult)
	Infill Drilling
B) Speculative Technologies:	Strategic Infill Drilling
	Pressure Cycling/Natural Gas

SOURCE Office of Technology Assessment based on Oec. 8 1987 workshop

techniques beyond ones currently in use are likely to be implemented.

OTA reviewed available current estimates of individual field production rates and ultimate recovery and concluded that the projections in Figures 3-3 through 3-6 are reasonable. In some cases, the data may be either too optimistic or too pessimistic, but, on average, the estimates are as accurate as available information will permit. The total TAPS production estimates in Figure *3-2* seem to adequately bracket the high and low range of future production possibilities.

Future "surprises" at Prudhoe Bay, the dominant field, are unlikely; Prudhoe appears to be the most monitored and computer-modeled field in the world. Futihermore, the operators have foreseen Prudhoe Bay's decline and have been working over a long period of time to keep production high and maximize recovery. There may be, however, a conflict between keeping production high and maximizing ultimate recovery. Some researchers have noted, for example, that increasing the production of natural gas liquids through TAPS, as industry plans to do, may beat the expense of increasing the miscible gas injection project. This could therefore lead to higher production now and lower ultimate recovery. OTA has not investigated the impacts of these details of reservoir management in order to reach an independent conclusion but only notes that choices are not always clear and sitnple.

The other three fields also do not appear to have many surprises in the offing, and, even if they did, the impact would be minor in relation to TAPS throughput. Kuparuk requires substantial conventional work, such as infill drilling, to keep production up. With waterflood and miscible gas projects in place, the future EOR opportunities that are available are a few of the more exotic chemical flooding techniques. These techniques require further study and testing. Endicott to date is as good a performing field as Prudhoe, and lessons from Prudhoe can best be applied there.

Lisburne is a very difficult field to produce, and disappointing results to date have downgraded its future potential. Some researchers have advocated more experimental technologies to be tried at Lisburne, but this would probably require industry development and testing beyond that justified by today's economics.

The optimistic view of new EOR technologies improving ultimate North Slope recovery appears to be that improvement, if any, will be slow and incremental. Over the next decade the total improvement may be expected to be about 10 percent. Improvements would need to come from advanced techniques that will require testing and capital expenditures beyond what indust~ claims are presently economically justifiable.

The discovered but still undeveloped fields on the North Slope of Alaska do have the potential to take up some of the slack that will be created when the Prudhoe Bay and Kuparuk fields begin to decline in several years, and application of enhanced oil recovery technologies to known North Slope fields will result in additional reserves. However, neither development of currently undeveloped fields nor the success of EOR projects nor both together is likely to stem the inevitable decline of TAPS thoughput.

OIL PRODUCTION FROM UNDISCOVERED RESOURCES

Alaska's North Slope still contains areas of potential hydrocarbons that the oil industry has never explored or that have received only minimal attention. In prospective offshore areas, for instance, no exploration has yet taken place in the Chukchi Sea, and very little has taken place in the Beaufort Sea adjacent to and north of ANWR. Even the more explored central and western portions of the Beaufort Sea have been barely scratched. Onshore, only one well has been drilled in ANWR, and although a number of unsuccessful wells have been drilled in the National Petroleum Reserve in Alaska, some experts still see the possibility of a commercial discovery in this vast area.

Both the State of Alaska and the Federal Government have scheduled a number of lease sales in the next 5 years. The State plans to hold four offshore and five onshore lease sales on State lands in northern Alaska, while the Federal Government has scheduled two offshore sales in both the Beaufort and Chukchi seas in its most recent 5-year plan (Table *3-7).* Discovery of new oil resources on the North Slope could, if large enough and in favorable locations, help keep oil flowing through TAPS. However, a sizable field discovered in 1988 probably would not be producing before 1998, given the long lead times needed to bring a new North Slope field on line.

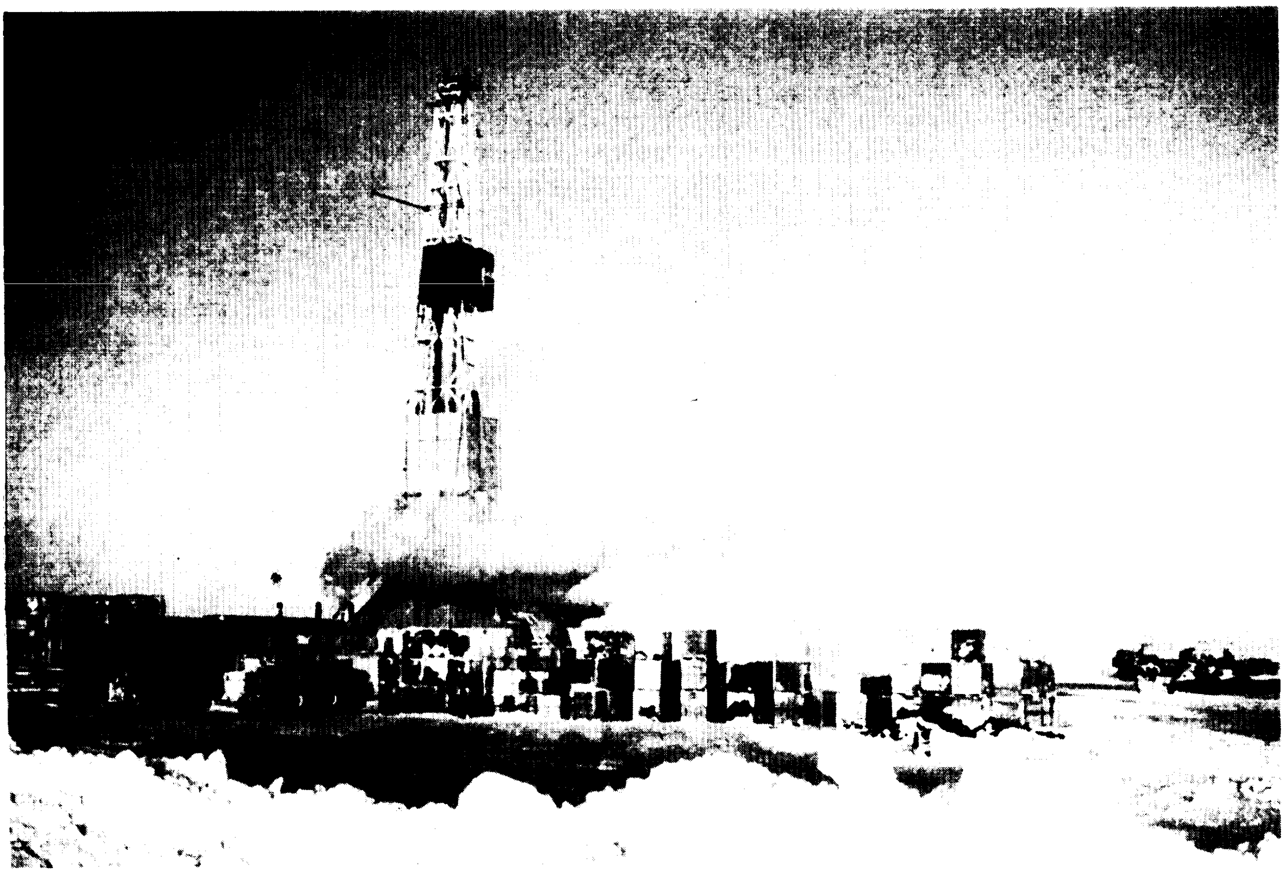


Photo credff Arctm S/ope Consu/t/r?g Engineers

Chevron's KIC well near Kaktovik is the only onshore exploratory well to probe the oil resources of the ANWR coastal plain. The results are a closely guarded secret.

Table 3~7.—Alaska Lease Sales

Number	Sale	Sale date
A. Proposed Alaska OCS Region Sales		
97	Beaufort Sea	March 1988
109	Chukchi Sea	May 1988
107	Navarin Basin	December 1989
101 •	St. George Basin	February 1990
1 14*	Gulf of Ak./Cook Inlet	September 1990
117	N. Aleutian Basin	October 1990
124	Beaufort Sea	February 1991
126	Chukchi Sea	May 1991
120’	Norton Basin	September 1989
129’	Shumagin	January 1992
133’	Hope Basin	May 1992
130’	Navarin Basin	January 1992

“To be held only [f Industry Interest warrants

SOURCE U S Department of the Interlor, April 1988

Number	Sale	Sale date
B. Proposed State of Alaska Sales		
54	Kuparuk Uplands	January 1988
55	Demarcation Point	June 1988
66A	North Slope Exempt	June 1988
52	Beaufort Sea	January 1989
56	Alaska Peninsula	June 1989
67A	Cook Inlet Exempt	June 1989
59	Cook Inlet	January 1990
57	North Slope Foothills	June 1990
64	Kavik	January 1991
65	Beaufort Sea	June 1991
61	White Hills	January 1992
68	Beaufort Sea	June 1992

NOTE North Slope sales bold

SOURCE Alaska Department of Natural Resources Division of 011 and Gas

Estimates of undiscovered oil may be useful for a number of reasons. These estimates may be used for 1) making long-term energy policy, 2) forecasting rates of domestic discovery and supply, 3) anticipating environmental impacts of exploration and production, 4) making investment decisions, 5) anticipating future technology and capital requirements, 6) realistically evaluating regulatory options, 7) scheduling lease sales, 8) conducting cost-benefit studies of leasing alternatives, and/or 9) analyzing the economics of Industry’s bids on leasable tracts.[38] Estimates ‘’ the undiscovered resources on the North Slope of Alaska are needed for all of these reasons. Several techniques are available for estimating the amount of undiscovered resources a region may contain (see Appendix B). Even with the best techniques available, estimates of undiscovered resources are inherently much more tentative than estimates of resources in known fields.

Estimates for the North Slope

The expectation of the early 1980s that more major oil resources would be found on the North Slope and in other parts of Alaska has not yet been realized. All of the currently producing onshore fields were discovered in the late 1960s, and no significant new discoveries have been made. Offshore areas have been judged by many[39] to be particularly promising, but the only offshore development to date is Standard Alaska Production Company’s Endicott field, discovered in 1978. After considerable exploratory drilling, the only noteworthy offshore discovery in the 1980s has been Shell’s Seal Island, a field that is not economic to develop at current low oil prices.

While much oil probably remains to be discovered both onshore and in still relatively unexplored offshore areas, it is unlikely that undiscovered resources will be found and developed in time to keep the Trans Alaska Pipeline running at full capacity after 1990. Lead times for development of 15 years or more may be required in some of the more remote places. in any case, new oil discovered in Alaska will not necessarily be found in proximity to TAPS and, hence, may require installation of an alternative transportation infrastructure. Also there has been a slowdown in exploration spending since 1985 because the current price of oil is low.

Several estimates of the undiscovered, economically recoverable resource potential of Alaska have been made. In 1981, the U.S. Geological Survey (USGS) estimated the risked mean of undiscovered, economically recoverable oil offshore Alaska to be 12.2 billion barrels and of natural gas to be 64.6 trillion cubic feet;[40] onshore Alaskan oil and gas resources were estimated to be 6.9 billion barrels of

38. National Research Council, **Offshore Hydrocarbon Resource Estimation: The Minerals Management Service’s Methodology (Washington, D. C.: The National Academy Press, 1986), p. 5.**

39. See, for instance, National Petroleum Council, U.S. Arctic Oil and Gas, December 1981.

40. US, Geological Survey, Circular 860, Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, 1981.

oil and 36.6 trillion cubic feet of natural gas. In 1985, the Minerals Management Servicce (MMS), which **as**sumed the offshore leasing responsibilities of the Consevation Division of the U.S. Geological Survey in 1982, again estimated offshore undiscovered resources. The newer assessment concluded that Alaskan Outer Continental Shelf (OCS) areas contained 3.3 billion barrels of undiscovered, economically recoverable oil and 13.9 trillion cubic feet of gas. This volume is much lower than the 1981 estimates. MMS assessed only OCS resources (i.e., resources beyond the 3-mile-wide band of State-controlled waters) while the previous USGS estimate considered all offshore resources together, MMS also used a different estimation methodology and revised some of the assumptions used in the earlier USGS estimate. Still, most of the reduction in the estimate of offshore undiscovered, economically recoverable resources probably can be accounted for by the disappointing offshore exploration record between 1981 and 1985 (Table 3-8).

In May 1988, the Minerals Management Service and the U.S. Geological Survey released preliminary data from a new study of the Nation's undiscovered oil and gas.[42] The new study incorporates a great deal of new data and uses improved estimation methodologies.[43] The USGS estimated onshore resources and resources in State waters; MMS estimated resources in Federal OCS waters. The new USGS estimate of undiscovered, economically recoverable resources for the total of onshore and State offshore areas of the United States is considerably smaller than the 1981 estimate. The picture for Alaska is less dear. The preliminary 1988 estimate indicates a risked mean of approximately 8 billion barrels of oil in onshore areas and in Alaskan State waters. The corresponding 1981 figure, 6.9 billion barrels, does not differentiate between State and OCS waters, thus making comparisons between the two estimates difficult; however, given the magnitude of USGS's 1981 combined estimate of onshore and shelf offshore oil, a reduced estimate can be inferred.[a]

Table 3-8.—Estimates of Undiscovered, Economically Recoverable Oil in Alaska (risked mean billion barrels)

	1981[a]	1985[b]	1988[c]
Offshore			
Beaufort Sea	7.8	0.89	0.21
Navarin Basin	1.0	1.30	0.03
Chukchi Sea	1.6	0.54	0.59
St. George Basin	0.4	0.37	0.01
Norton Basin	0.2	0.09	—
Other	1.2	0.11	0.06
Total Offshore Alaska	12.2	3.30	0.90
Onshore	6.9	—	7.91

[a]1981 offshore estimates are for oil in both Federal and State waters. The onshore estimate does *not* include oil in State waters.
[b]1985 offshore estimates are for Federal waters only.
[c]1988 offshore figures are for Federal waters. The onshore figure is for onshore and State waters. 1988 estimates are preliminary and subject to modification. Totals for onshore and offshore Alaska were not added in the preliminary National Assessment; hence, OTA summed the province numbers to reach the totals in the table.

SOURCES: U.S. Geological Survey, Circular 860, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, 1981; Minerals Management Service, MMS 85-0012, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf as of July 1984*, 1985; U.S. Department of the Interior, *National Assessment of Undiscovered Conventional Oil and Gas Resources*, USGS-MMS Working Paper (Preliminary), Open File Report 88-373. 1988.

Alaskan OCS data also have been revised. Preliminary offshore estimates of undiscovered, economically recoverable oil indicate substantially less oil than was estimated in MMS's 1985 estimate. Since 1975, over 90 exploration wells have been drilled in the State and Federal waters of the Beaufort Sea and in the Navarin, Norton, and St. George Basins in the Bering Sea.[45] Few of these exploration wells struck "producible" quantities of oil.[46] Only one offshore discovery,

41, U.S. Congress Office of Technology Assessment, Oil and Gas Technologies for the Arctic and Deepwater (Washington, DC: U.S. Government Printing Office, 1965), p. 30.

42. U.S. Department of the Interior, National Assessment of Undiscovered Conventional Oil and Gas Resources, USGS-MMS Working Paper (Preliminary), Open File Report 68-373, 1986.

43. The playanalysis methodology used by USGS and MMS and underlying geologic assumptions will be reviewed before final publication of the report,

44. The mean total for onshore oil and shelf offshore oil was estimated in 1981 by USGS to be 17.7 billion barrels. Some of the shelf offshore oil would be expected to be found in State waters.

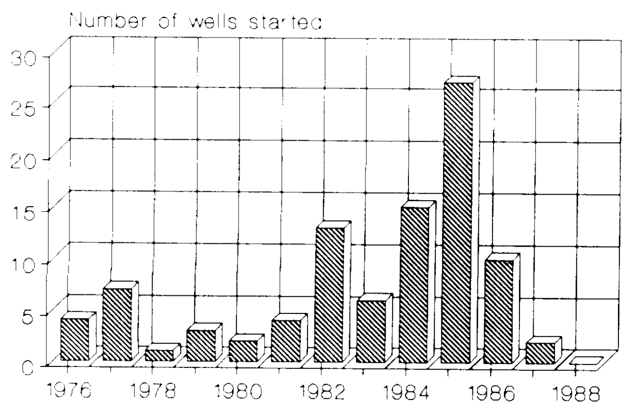
45. W.W. Wade, "Exploration and Production in Alaska: A Review and Forecast," World Oil, February 1986, p. 101.

46. That is, few were determined to be "producible" in accordance with OCS Order No, 4.

the Endicott reservoir, located in shallow State waters, has been developed to date; only two other likely commercial discoveries have been made, Niakuk and Seal Island. Niakuk is in very shallow State waters adjacent to the existing Prudhoe Bay infrastructure and, hence, may possibly be producing by the early 1990s. Seal Island has been the only OCS discovery to date (although, as noted previously, its OCS status is being disputed by the State of Alaska).

The most notable disappointment in OCS exploration was Sohio's Mukluk prospect in the Beaufort Sea. The Mukiuk structure **was con-** sidered the most promising prospect in the Beaufort during 1983, but the failure to discover oil there transformed it into the most costly dry hole in history ($140 million in drilling and island construction costs and over $1 billion in total costs). The Mukluk dry hole figured prominently in the substantial lowering of Beaufort Sea resource estimates in MMS'S 1985 reassessment of undiscovered, economically recoverable resources.

Figure 3-7.-Exploratory Wells in the Beaufort and Bering Seas, 1976-88



SOURCE U S Department of the Interior, Minerals Management Service, Alaska/ Summary Index, January 1966-December 1966, pp. 26, 27, 39

Offshore areas remain relatively unexplored, but the lack of drilling success since 1985 is a major reason for the lower 1988 estimates. Furthermore, low and volatile oil prices have dampened enthusiasm. Exploratory drilling activity has dropped off sharply since the peak year of 1985 (Figure 3-7). Only one well has been drilled thus far in 1988, Tenneco's Aurora well about 4 miles off the coast of the Arctic National Wildlife Refuge, and no others are expected. However, higher and more stable oil prices would likely stimulate higher levels of offshore exploration in the future.

Estimates for ANWR

Although much is said and written about the resource potential of ANWR, it is still a virtually unknown area, and a wide range of resources is possible in ANWR'S coastal plain. Much depends, for instance, on the existence and thickness of Ellesmerian sequence rocks in the ANWR area, and State and Federal geologists differ in their assessment of these rocks. Both the State of Alaska and the U.S. Department of the Interior (DOI) have used play analysis to estimate the in-place resource potential of ANWR. The State used a model known as the Resource Appraisal Simulation for Petroleum (RASP) to estimate undiscovered resources there. DOI used a modified version of the play analysis technique developed by the Geological Survey of Canada to estimate ANWR'S potential in its mandated report to Congress. The DOI assessment is driven by an efficient computer program known as the Fast Appraisal System for Petroleum (FASP) (see Appendix B for a discussion of these models). Both models use information gained through seismic work and through studies of ANWR'S surface geology; both models depend for much of their input on the opinions of geologists familiar with the area; and both models report their results as probability distributions rather than as single point estimates.

The State reports that there is a mean of 7.22 billion barrels of in-place oil in ANWR while DOI reports a mean of 13.8 billion barrels. Given the lack of information about ANWR'S subsurface geology, it is not surprising that DOI and State of Alaska estimates differ at all probability levels (Table 3-9).[47] Although the results differ, both studies conclude: a) that the key elements for petroleum accumulations are present beneath the coastal plain of ANWR, b) that there is only a smail possibility that unusuaily large petroleum resources are present, and c) that there is a greater likelihood that resources more moderate in size are present.[48]

One thing is important – much of the difference between the two estimates is due mainly to subjective factors. For instance, DOI and Aiaska geologists identified different geological plays for anaiysis (not unusual given the limited geoiogic data available), had quite different opinions about the quantity of potentially oil-bearing Ellesmerian sequence rocks in the area, and disagreed about the contribution of pre-Mississippian rocks for oil accumulation.[49] Had the same subjective information been used in each study, the DOI and State estimates using FASP and RASP wouid have been about the same, but the estimates would not necessarily have been more accurate, Subjective factors necessarily introduce a considerabie amount of uncertainty in estimates of undiscovered resources. Drilling data is not available for ANWR's coastal plain.

Table 3-9.—Comparison of Estimates for Undiscovered In-place Oil in ANWR

Probability y greater than	State of Alaska RASP	Department of Interior FASP
95%	0.08 BBO[a]	4.8 BBO
75%	1.28	8.2
50%	3.77	11.9
25%	9.18	17.2
5%	26.52	29.4
Mean	7.22	13.8

[a]To be read, "there is a 95% probability the in-place oil resource is greater than .08 billion barrels."

SOURCE Alaska Department of Natural Resources, "Overview of the Hydrocar. bon Potential of the Arctic National Wildlife Refuge Coastal Plaln, Alaska, " report of investigations 87-7

The Department of the Interior estimated economically recoverable resources using the PRESTO (Probabilistic Resource Estimates-Offshore) model. With PRESTO, DOI estimated that **if** at least one field with commercially recoverable quantities of oil is present in ANWR, then there is likely to be a mean of at least 3.23 billion barrels of recoverable oil, a 5 percent probability of at least 9.24 billion barreis, and a 95 percent probability of at *least* 590 million barrels. Note that these estimates are very sensitive to DOI's minimum areawide economic field size, which in turn is dependent on the assumed price of oil (in this case, world oil prices at $35 in the year 2000 in 1984 doilars, with North Slope oil $33 because of market conditions).

The Energy Information Administration (EiA) also estimated the undiscovered, economically recoverable resources of ANWR. EIA assumed that 25 percent of the in-place resources estimated in the DOI study would be recoverable, basing its assumed recovery factor on the approximately 26 percent area-wide recovery factor for known North Slope fields.[50] This assumption resuits in a base case estimate of 3.45 billion barreis of recoverable oil. If EIA had applied the same recovery factor to the State's in-place estimate, the comparable undiscovered, economically recoverable estimate would be 1.8 billion barrels. OTA has no basis for concluding that one estimate is more accurate than the other, i.e., for using DOI's mean oil in-place figure versus using Alaska's figure.

Note that the EIA and DOI estimates are not as similar as they appear. The DOI estimate depends on the existence of at least one commercial field, and, according to DOI, there is a 19 percent chance that such a field exists in ANWR. The EIA estimate assumes the probability of finding economically recoverable oil is nearly 100 percent (uncondition-

47. J.J. Hanson and R.W. Kornbrath, "AComparison of State and Federal Appraisals of the Arctic National Wildlife Refuge Coastal Plain," Staff paper, Alaska Department of Natural Resources, Division of Mining and Geology, 1987,

48. Ibid., p. 4.

49. Ibid., p. 3.

50. Energy Information Administration, Potential Oil Production From the Coastal Plain of the Arctic National Wildlife Refuge, October 1987.

al); EIA reasons that the geologic ingredients are present, that traps exist other than those used by DOI in its PRESTO analysis, and that oil accumulations smaller than *440* million barrels can be economically recovered.

Various groups support DOI's risked mean estimate of approximately 600 million barrels–that is, *3.23* billion barrels multiplied by the probability of finding economically recoverable oil (19 percent), –as the appropriate measure of ANWR's resource potential. In OTA's view, the more appropriate interpretation of the DOI analysis is that there is an 81 percent chance that no economically recoverable resources will be discovered in ANWR, but if there are any economically recoverable resources at all, there will be a mean of at least 3.23 billion barrels.

On the other hand, if approximately 3.5 billion barrels of recoverable oil are found in ANWR, OTA considers peak production of about 800,000 barrels per day from two producing fields to be reasonable (see OTA scenario – Table 2-4– in Chapter 2). Production that started in *2002* might peak by 2008 and then decline at a rate of about 12 percent per year.

OIL INDUSTRY COST-CUTTING AND THE EFFECT ON OILFIELD DEVELOPMENT

Oilfield costs during the past 15 years have been linked to oil prices. When prices were rising, costs also tended to rise after a short time lag. One reason was that the sellers of equipment and services were able to raise their prices and increase their profit margins when rising prices spurred oilfield activity levels and when the demand for services and equipment outran the supply. Another reason was that rising oil prices tended to dull the incentive for innovative, cost-cutting design and operation. When oil prices began to fall, beginning in 1981, oilfield activity levels dropped, and prices for drilling and other services fell substantially. When oil prices nosedived in late 1985, prices for equipment and sewices fell along with them. In many areas, for example, day rates for rigs fell more than 50 percent. At the same time, extensive cost-cutting in the industry streamlined oilfield activities so that the actual number of mandays and equipment-days required to complete projects was dramatically down.

For example, the industry drilled about 92,000 wells in 1981 with nearly 4,000 rotafy rigs active; 84,000 wells in 1982 with 3,100 ri s active; and 85,000 wells in 1984 with 2,400 rigs.[51] This improvement in "rig efficiency" is a complex function of actual efficiency improvements and other factors, such as changing geographical drilling patterns, shifts in the balance of oil and gas targets, and lower levels of exploration. Unfortunately, it is difficult, if not impossible, to separate out the roles of the various causal factors in the chan es in this and other measures of oitfield efficiency. Thus, it is not possible to predict reliably what portion of this increased efficiency would remain if oil prices rebound or other oilfield conditions improve. Nevertheless, OTA believes that there is sufficient evidence to conclude that a significant portion of the measured increases in efficiency represent real increases and are not merely statistical artifacts.

Anecdotal evidence implies that the North Slope has seen considerable cost-cutting success. For example, Standard Alaska Production Company claims to be drilling development wells at Endicott for *40* percent of the originally projected cost–with no reduction in time rates for rigs–and the overall cost for developing the field was about one-third of original projections ($1.3 billion final cost, $3.8 billion conceptual estimate[53]). The majority of the savings came from a combination of additional knowledge of the resource that dictated less expensive requirements and lower material and labor costs because of the general slowdown in oilfield activity– cost reductions that are not likely to be repeatable. A substantial part of the savings, however, resulted from Standard's conscious decision to scale-back and redesign the project. Cost-saving measures included:

- using fewer but larger production modules;
- using self-propelled, cantilevered drilling rigs to allow smaller spacing for wells and to reduce time for well-to-well moves;
- changing the design from one island to two, reducing drilling costs;
- building a gravel causeway rather than undersea pipelines; and
- using a single, rathe~~han a redundant, oil-processing system-[54]

None of these changes are dramatic technological breakthroughs, and all could well have been implemented without the decline in oil prices that began in 1981. However, it seems likely that the price drops were the proximate cause of the process that led to these savings.

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51. U.S. Congress Office of Technology Assessment, U.S. Oil Production: The Effect of Low Oil Prices- Special Report, OTA-E-348 (Washington, DC: U.S. Government Printing Office, September 1987).

52. Ibid.

53. Ml. Curtis and D.B. Huxley, "Endicott Development-Making the Arctic Offshore Economical," Twelfth World Petroleum Congress, Houston, Texas, 1987.

54. Ibid.

Photo credit Standard Alaska

Endicott Field, August 1987. Careful redesign allowed substantial cost savings at this field,

The result of these and other cost-cutting successes is that, as oil prices have declined, the "breakeven" oil prices for project development have declined as well. Consequently, projections of reduced activity levels (because of low oil prices) that relied strictly on previous estimates of project costs should be viewed as overly pessimistic. Also, if oil prices rise back to previous levels, much of the "benefit" associated with the period of low prices would remain. For example, the rates for services probably would rise also, but not to previous levels. Higher efficiency reached during the period of low oil prices would probably remain, except for temporary losses that might occur if the demand for oilfield services and equipment outstripped the capacity of the providers. The net result would be that a return to previous oil price levels might find the industry capable of doing more project development than was economic at the time of the previous price peaks,

The oil industry's ability to cut costs in the face of low oil prices implies that projections based on previous cost estimates should be viewed somewhat skeptically. This view applies to production projections for the entire North Slope as well as to estimates of the oil price necessary to develop a 500-million-barrel oilfield in the Arctic National Wildlife Refuge. For the North Slope, the ability of the industry to complete projects at lower costs makes it likely that the more optimistic of the available production projections–forecasting a 25 percent decline in production by 2000–

is the more realistic of the two presented previously. However, basic resource constraints and the unavailability of any "breakthrough" enhanced oil recovery technologies implies that still higher production levels are unlikely. For ANWR, OTA tends to agree with the Energy Information Administration's argument that DOI'S estimated MInimum Economic Field Size (MEFS) is probably too large[55]—that a $35/bbl oil Price (1984 dollars) would allow the development of a field smaller than DOI's MEFS of 440 million barrels of economically recoverable oil, or else that a 440-million-barrel field could be developed at a price lower than $35/bbl (see Box 3-B).

N W R m
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55. Energy Information Administration, Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, revised edition, SR/NGD/87-01, October 1987.

BOX 3-B
HOW MUCH OIL IS IN THE ANWR COASTAL PLAIN?

The decision to allow or block leasing of the ANWR coastal plain depends on balancing the potential damage that expiration and development may cause the wilderness, wildlife, subsistence, *and* other values with the value of the potential oil resources, Resource estimates for undrilied regions are notoriously subjective and inaccurate, however, and Congress should view the Department of Interior's estimates of ANWR resources as "best guesses" rather than as accurate measurements, Nevertheless, the methods and assumptions used by DOI **can be reviewed** objectively, and an evaluation can be made of the degree to which the **estimates may be conservative or optimistic. OTA** has examined DOI'S documentation of its economic assessment and reviewed critiques of the assessment. In our view, the assessment is more likely to have produced results that are conservative, that is, resuits that are more pessimistic **about the** likely recoverable oil than the evidence suggests. OTA did not review DOI's geologic assessment that produced estimates of total in-place oil, but we note that this assessment is substantially more optimistic than the assessment produced by the State of Alaska. Because the estimate of total recoverable resources reflects both the geologic assessment of in-place resources and the economic assessment of recoverability, OTA is reluctant to conclude that DOI's estimate of total recoverable oil resources in the ANWR coastal plain is either conservative or optimistic. On the other hand, we conclude that DOI's estimate of the likelihood that economically recoverable quantities of oil will be found in ANWR –19 percent at world oil prices of $35/bbl (1984 doilars) – probably is overly pessimistic.

Opponents of development have argued that the DOI estimates of ANWR resources are overly optimistic because DOI assumed unrealistically high world oil prices –$35/bbi (1984 dollars) refinery acquisition costs by the year 2000 with a continued growth in "real' prices beyond 2000 of 1 percent per year. 'f Because the size of the "minimum economic field" –the smallest oilfield that could support the pipeline **and** other facilities needed to produce and transport ANWR oil – is inversely dependent on oil prices, lowering the assumed prices would tend to increase the minimum field size and thus reduce the estimated probability of finding commercial quantities of oil in ANWR. Lowering the **assumed** oil **price** would also affect the estimated volume of recoverable **oil.** However, the effect appears somewhat pewerse because the estimated "mean" voiume of oil, assuming that economic amounts are found, actuaily increases if assumed oil prices are lowered. This counterintuitive effect occurs because reducing the minimum field size adds a number of lower-resource possibilities to the universe of resource possibilities sampled by DOJ's probabilistic model, In reality, of course, if economic quantities of oil exist In ANWR, **a** lower oil price would tend to decrease the volume of oil recovered.

The assumed oil **price is only one of several factors that may affect the reliability of the** economic assessment. These factors include:

1. **Including or excluding 'Sunk Costs."**[2] */n determinating the mi'nimum economic fieid size (MEFS), the costs of exploration and delineation weils are included in the total costs that must be balancecf by the economic value of the oil found.* Assuming that a company purchases a iease and begins exploration, if it then discovers a field it will treat ail prior costs– inciuding the costs of exploration –as sunk in determining whether or not to proceed with commercialization. Hence, an oii company may choose to proceed with development even

1, J.S. Young and W.S. Hauser, Economics of Oil and Gas Production From ANWR for the Determination of Minimum Economic Field Size, Bureau of Land Management Report PT-87-015-3120-985.

2. Sunk costs are costs that have already been incurred and cannot be recovered if the project fails.

if the total costs exceed the economic value of the oil. The DOI assumption Ignores this possibility.

2. **Including or excluding the possibility of "clusters" of small fields.** *The MEFS is calculated on the basis of its stand-alone prospects. In other words, each prospect is evaluated on the bask of its ability to pay for all of the infrastructure necessary to develop the field, including the main pipeline to TAPS Pump Station #l in the Prudhoe Bay area.* In reality, two or more fields can share the costs of production facilities, the main pipeline, and other infrastructure costs. Also. offshore development in the Beaufort Sea could share infrastructure costs with onshore fields.[3] Consequently, there is a realistic possibility-Ignored by the DOI quantitative analysis–that ANWR 011 could be developed even though no single field exceeds the MEFS.

3. **Selection of the assumed tax and royalty system.** *The income taxes paid by a field developer are calculated using the terms of the tax system prior to the* 1986 *changes in the tax law. These* terms include allowance of investment tax credits, 80 percent expensing of intangible drilling costs, ACRS depreciation for 5-year property for tangible drilling costs, and a 46 percent Federal income tax rate. The industry has claimed that the result of the 1986 changes, on balance, has been to reduce the incentive to find and develop new fields. Thus, using current tax rules might tend to lower the estimated oil potential in ANWR.

4. **Assumed oilfield costs.** The estimated costs of drilling, building the pipeline, and other necessary construction and operations are based on the 1981 National Petroleum Council report on Arctic oil and gas,[4] supplemented with other data. According to industry reports, experience of the past few years–especially following the severe oil price drop of 1985/86-has demonstrated that the costs of Arctic operations can be reduced significantly, For example, both ARCO and the Standard Alaska Production Company claim to have reduced development drilling costs sharply by Increasing drilling efficiency. Thus, there is a strong possibility that the DOI cost data overstates the likely costs for ANWR field development and depresses the estimated oil potential.

5. **Assumed oil prices.** in its base case, DOI assumed that world oil prices would rise to $35/bbl in 1984 dollars by 2000 and would then rise in real terms by 1 percent per year thereafter. DOI's analysis clearly demonstrates that the estimates of MEFS– and thus the likely resource value - are highly sensitive to the assumed oil price. For example, for a field in the western portion of ANWR, MEFS is 425 million bbl at a $35/bbl oil price and 1.39 billion bbl for a $22/bbl oil prices Although DOI's price assumptions have been severely criticized, OTA believes that oil prices could attain this level if current forecasts of future world oil demand and supply trends prove to be correct. There are, however, plausible circumstances that would maintain prices significantly below this level. in OTA's view, the range of plausible year 2000 oil prices is wide– probably at least from $22 to $40 per barrel in 198? dollars–and there is no way to select a "most likely" price that could achieve any kind of consensus.

6. **Inclusion or exclusion of geologic targets.** *The DOI recoverable resource analysis is restricted to the* 26 *largest structural prospects identified by the initial geophysical surveys of the area.* As noted in DOI's ANWR Resource Assessment,[6] additional amounts of economically recoverable oil may be present in smaller structural traps and in so-called stratigraphic traps

3. These factors are discussed in the Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, April 19S7.
4. National Petroleum Council, U.S. Arctic Oil and Gas, December 19S1.
5. Young and Hauser, op.cit., Box 3-B, footnote 1.
6. U.S. Department of the Interior, Arctic National wildlife Refuge, Alaska, Coastal Plain Resource Assessment, April 1967.

that were not identified by the available geophysical? information. Including these additional prospects should increase the estimated values of both the probability of finding economically recoverable oil in ANWR **and the mean recoverable resource.**

The first, second, fourth, and sixth factors tend to understate the likely oil potential in ANWR; the third tends to overstate it; and the fifth gives **no clear direction. Overall, OTA believes that i)O1's economic evaluation of ANWR oil potential is likely to be too pessimistic, especiaMy with regard to the probability of finding a field of commercial size.**

The DOI assessment of ANWR'S oil potential is dependent on both the economic and geologic assessments, however. The geologic assessment prepared **by the State** of Alaska is **more pessimistic** than DOI's geoiogic assessment. For example, the State estimated the "50th percentile" in-place resource to be 3,77 billion barrels (that is, there is a 50 percent chance that there are at least 3.77 billion barreis of in-place resources) versus DOI's estimate of 11.9 **billion.** The primary factors causing the disagreement are sharply differing views of the likelihood of finding large volumes of oil-bearing Ellesmerian rocks in the coastal plain (the State largely discounts the role of the Ellesmerian) and differing estimates of success rates for indhddual wells (the State expects tower success rates than does DOI). Given the judgmental character of the estimates and the lack of drilling data, this level of disagreement is not **at all unusual.** However, the State's estimates would imply a much lower resource value for the ANWR coastal plain than the value assigned by DOI.

The Energy Information Administration (EIA) also has examined the DOI assessment of economically recoverable oil in the coastal plain. EIA concfuded that 1)01's assessment of in-place resources was reasonable, but it disagreed strongly with 001's evaluation of the risk of finding economically recoverable oil and also disagreed with DOI'S assessment of the likely magnitude of any recoverable resources. In particular, EIA **rejected DOI's estimate that there is only a is percent probability of finding oil in economically recoverable quantities; instead, EIA concluded that the probability of finding economically recoverable oil in ANWR is very high.** EIA **projects the likely economically recoverable oil in ANWR (at DOI's assumed oil prices) to be 3.4 billion barrels, with little likelihood (compared to DOI's 81 percent likelihood) that nothing will be recovered.** OTA generally agrees with **ElA's** qualitative assessment of 001's economic evaluation, We note, however, that ElA's alternative methodology for estimating ANWR recoverable resources is unsophisticated, relying on **a** simple extrapolation of the recovery rates of known North Slope fields. On the other hand, given the limited data on ANWR, ElA's slmple approach may prove just as accurate as the more detailed approach of DOI.

7. **Energy Information Administration, Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, revised edition, SR/RNGD/87-01. In its repo EIA arrived at essentially the same qualitative conclusions about the details of DOI's economic analylis as OTAdid and as hdiscussed them in more detail.**