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FEASIBILITY STUDY OF HEAVY OIL RECOVERY — PRODUCTION, MARKETING, TRANSPORTATION, AND REFINING CONSTRAINTS TO INCREASING HEAVY OIL PRODUCTION IN ALASKA

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ABSTRACT

This report is one of a series of publications resulting from a study of the feasibility of increasing domestic heavy oil production being conducted for the U.S. Department of Energy. This report summarizes available public information on the potential of heavy oil production in Alaska. Heavy oil (10° to 20° API gravity) exists and is produced on the North Slope of Alaska; but the technical, environmental constraints and high cost of transportation to refineries on the U.S. West Coast make the economics for producing significant volumes of heavy oil unfavorable. Volumes of proprietary data and feasibility studies exist within major companies, but only limited data is available in the public domain. Alaskan North Slope crude oil is marketed under the legislative constraints of having to be sold in the U.S., thus, it has to compete in the world market with a delivery constraint. California is the recipient and refines most of Alaska's current 1.7 million barrels per day oil production. Transportation, refining, and competition in the market limit development of Alaska's heavy oil resources. A number of enhanced oil recovery technologies for production of Alaska's heavy oil have been reported in the literature including gas, CO_2, in situ combustion, and steam. Thermal production of heavy oil has been attempted but requires close spacing. Several light oil reservoirs, with reserves of >50 million barrels each, have been discovered and deemed non-commercial. Constraints on producing heavy oil in Alaska indicate that without significant economic incentives, very little of the heavy oil in Alaska will be produced and even then the cost may be prohibitively expensive leaving most of Alaska's heavy oil unproduced.

EXECUTIVE SUMMARY

Previous estimates of the heavy oil (10° to 20° API gravity) resources in Alaska indicate a range from 5 to 35 billion barrels (bbl) of oil. Although volumes of proprietary data exist in company files, publicly available data are limited. Alaska produces heavy oil from the Milne Point field but the volume is small (<0.1%) of total Alaskan North Slope (ANS) daily oil production. On the basis of publicly available data, this study determined that little of the heavy oil in Alaska is likely to be developed without significant economic incentives and even then the cost may be prohibitively expensive compared to heavy oil in other parts of the U.S. or the world and thus

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most of Alaska's heavy oil may be unproduced. This oil has to compete on the world oil market even though legislative constraints mandate that ANS must be sold to the U.S. This constraint mandates that produced Alaskan heavy oil (AHO) must be refined either in Alaska or in the heavy oil refining areas of California or the U.S. Gulf Coast. This makes AHO compete directly with heavy oil produced in California where the transportation cost of AHO to California may exceed $10/barrel. Limitations are also imposed by the harsh environment of Alaska. The fragile Arctic tundra is supported by thick permafrost that must be maintained since the artificial islands in the permafrost are the support (base) for all drilling and production operations. This limits thermal recovery of the shallow heavy oil that is found scattered in the shallow fluvial-dominated formations on the North Slope that lay above lighter oils that are currently being produced. Reinjection of produced gas mandates that the heavy oil will be some of the last resources developed, since natural gas will be used to supplement pressure and as a solvent to recover more valuable lighter crude oil on the North Slope. Interior basins of Alaska are still unexplored and significant potential exists outside current fields for discovery of significant light, medium and heavy oils. Minimum throughput (300,000 barrels oil per day, BOPD) on the TransAlaska Pipeline (TAP) is a concern but heavy oil will not keep the pipeline full as the line was not designed to transport viscous heavy oil.

With current constraints, the heavy oil fields in California, Wyoming, and the Gulf Coast states (Texas, Arkansas, Louisiana, and Mississippi) will be developed long before Alaska's. The major heavy oil refining capacity is in California refining Californian, heavy and 70% ANS. The U.S. Gulf Coast will refine light oil and Caribbean blended heavy. A few Midwest refineries will refine Canadian blended crude (bitumen, upgraded bitumen and diluent) and light crudes. The price of heavy oil at the refinery gate will limit refining of AHO in California, as refiners will find imported Caribbean medium and heavy oil at a much lower price than AHO or will refine imported light and medium crude and make a better rate of return.

INTRODUCTION

As part of a nationwide assessment of the feasibility of heavy oil recovery conducted by NIPER (BE11B task 5 and SGP37), this report evaluates the factors affecting – and the feasibility of increasing – Alaskan heavy oil production. The term "heavy oil" as used in this report is oil of 10°-20° API (943-1,000 kg/m^3) inclusive at 60° F (15.6° C), and having a gas-free viscosity of 100-10,000 centipoise (MPas) inclusive at original reservoir temperature (Group, 1981). The objectives of this nationwide heavy oil feasibility study are (1) to investigate from publicly available data the known heavy oil resources; (2) to screen this resource for potential thermal or other enhanced oil recovery (EOR) techniques; and (3) to evaluate various economic facets that may have an impact on the expansion of heavy oil production (refining, transportation, environmental, etc.).

This portion of the study was undertaken because previous studies (Sharma, 1990) have indicated the existence of a significant heavy oil resource in Alaska. There is also growing concern that the decline in ANS crude oil production, currently (October 1992) at 1.705 million BOPD of 27° API gravity crude, contributing 23.8% of the total US production (Oil & Gas J., July 6, 1992), will have a significant impact on the U.S. energy supply (Fig. 1). Prudhoe Bay oil field has been on decline since May of 1989. Production is now restricted primarily by the amount of gas reinjection capability that currently exists at the North Slope (Krause et al, 1992), and not by the capacity of TAP or State off take restrictions, as was the case previously. Can Alaska continue to be the major U.S. oil producer if heavy oil is developed? Can thermal enhanced oil recovery, TEOR, (cyclic steam, steamflooding, and in situ combustion) technology be as successful in Alaska as it is in California – a model of TEOR success in recovering nearly half a million barrels of heavy oil per day (Moritis, 1990, 1992). This report provides a background listing some of the technical, economic, and environmental constraints to the production of AHO.

Alaska is believed to have huge heavy oil deposits, which at one time were thought to be as much as 35 billion barrels (Werner, 1984), of which 15 to 25 billion bbl was speculated to exist in

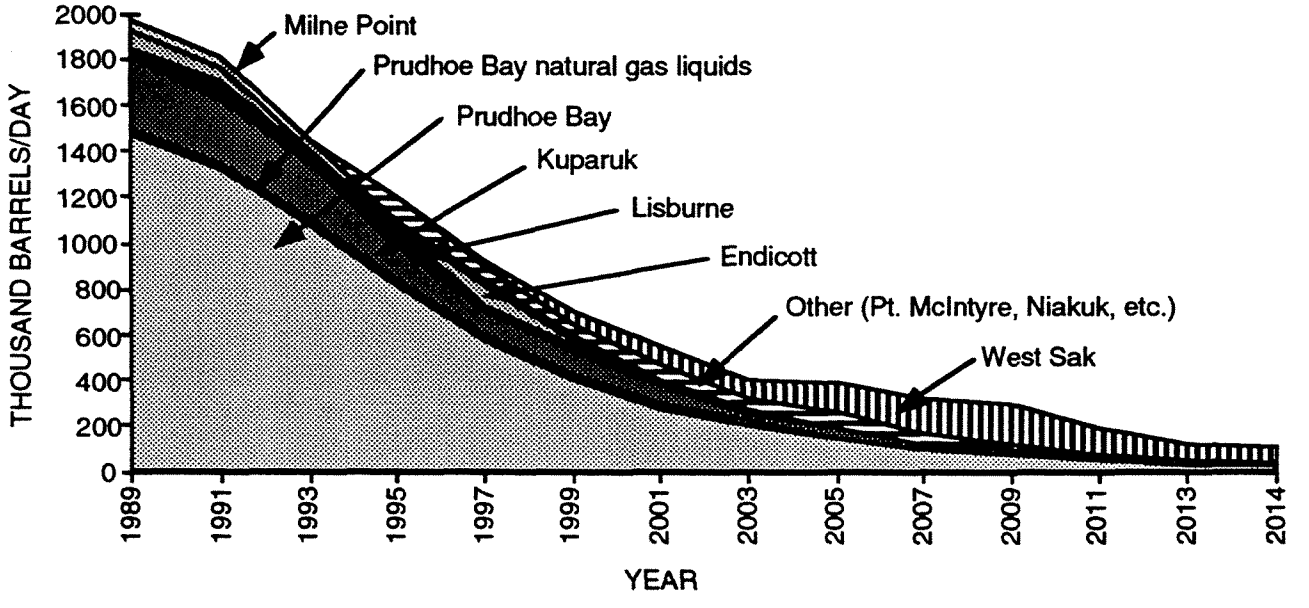

FIGURE 1. - Recent and projected production from North Slope of Alaska – (Thomas et al, Jan. 91).

the West Sak, and 11 to 19 billion bbl in Ugnu. ARCO's initial target was 25-30% recovery of the estimated 5-11 billion bbl of oil in place in the West Sak sands using thermal methods (Oil & Gas J, 1983). The original-oil-in-place (OOIP) in the overlying Ugnu reservoir was estimated to be 6-11 billion bbl, but no plans for its production were stipulated at that time. The pessimistic estimates, evidently based on further exploration and drilling in the last few years, have reduced these deposits to 5 billion bbl. Because of the low recovery factor, the recoverable oil is currently estimated to be only 423 million bbl in the West Sak, the most viable heavy oil reservoir (Thomas et al., 1991). The factors critical to the development of these resources are world oil prices, governmental policies, environmental constraints, availability of a transportation system to deliver the produced heavy oil to a suitable refinery, availability of capital, and rate of return on investment.

It has been proposed (Brashers, 1991) that an additional 0.93 million BOPD of heavy oil could be produced in the United States by the year 2010. This more than doubles current heavy oil production estimates of 0.8 million BOPD of heavy oil (Olsen et al., 1991) and is almost twice the current thermal oil production of about 0.46 million BOPD (Moritis, 1992). Because the economics of producing heavy oil is not as favorable as that of light oil, a major effort by both the government and industry is needed to increase the heavy oil production by this magnitude. The apparent consensus among operators is that AHO production — at current world oil prices — is only marginal, if feasible at all. If the price of heavy oil increased significantly, as occurred in the early 1980s, domestic heavy oil production would undoubtedly increase. This scenario is unlikely in light of increasing imports of light and medium oil below $25/bbl, as shown in Fig. 2.

Most of the data on Alaska is still confidential and publicly known information comes from news releases and briefings that contain little technical data. The University of Alaska, the Alaska Oil & Gas Conservation Commission, and more recently, the DOE (through EG&G Idaho, Inc.) have been the major sources of public information about these resources. This report refers to these sources for most of its technical data. Occasionally, the report refers to news briefs found in various trade journals. The major objective of this report is to briefly summarize, compile, analyze and present the relevant public-domain information in a simple and concise manner.

RESULTS AND DISCUSSION

Location of Heavy Oil Deposits in Alaska

Figure 3 shows the major oil producing fields in Alaska. Most of the production is from the North Slope that has more than 95% of the known proven oil resources in the state. A map of the North Slope showing the TransAlaskan pipeline, Naval Petroleum Reserve, Arctic National

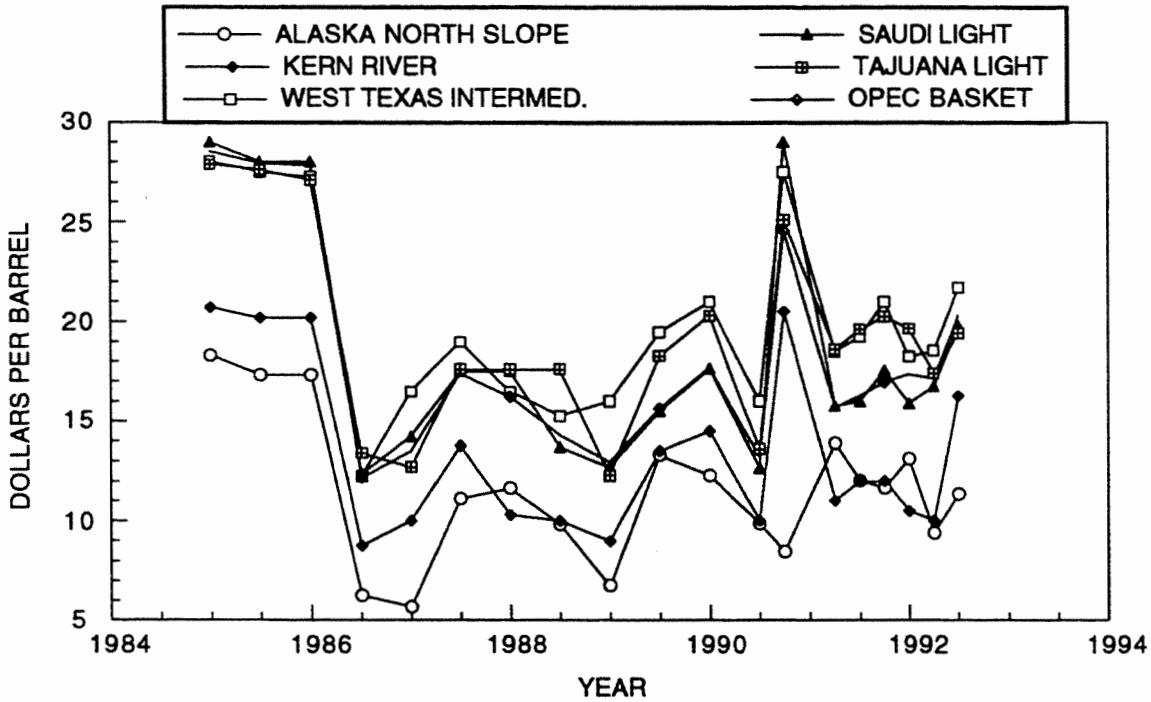

FIGURE 2. - Historic posted oil prices for various crude oils since 1985 – (Oil & Gas J., 1985-1992).

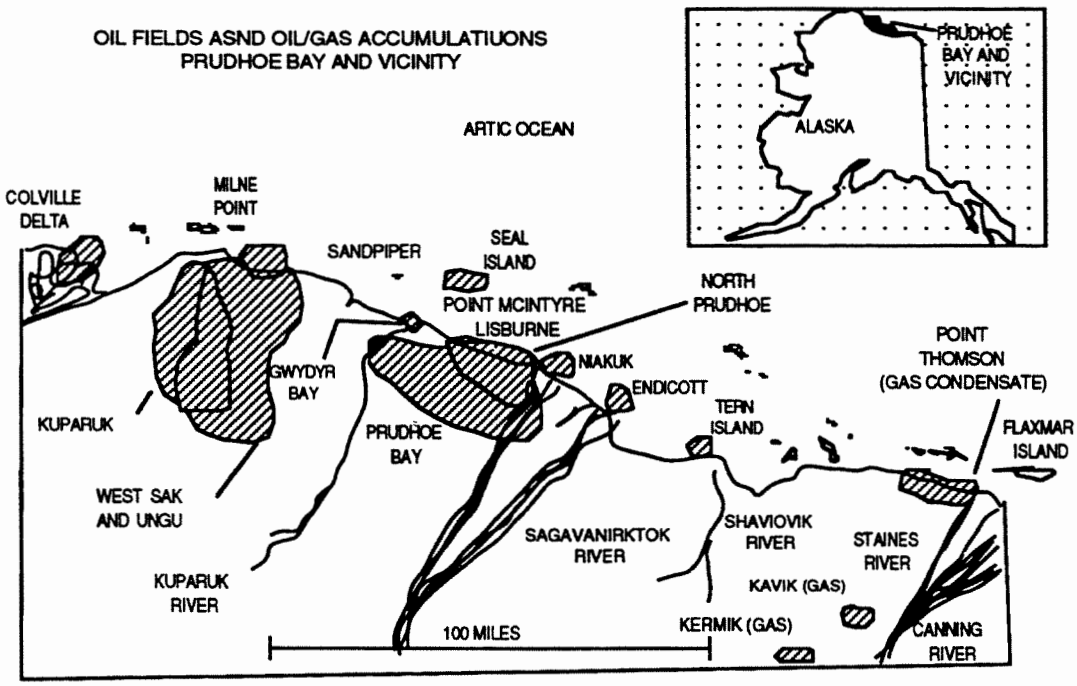

FIGURE 3. - Location of Alaskan oil and gas accumulations, highlighting North Slope fields – (Thomas et al., 1987).

Wildlife Refuge and major geologic features is illustrated in Fig. 4. Figure 5 is a composite well log and formation nomenclature for North Slope fields. Figure 6 is an index map for developed units of this area. Kuparuk River field is known to have huge deposits of both heavy and light oils. Most heavy oil in Alaska is in three shallower formations (Fig. 7), Upper Ugnu, Lower Ugnu, and West Sak, whereas the deeper Kuparuk sands (not shown in the figure) contain light oil.

The combined thickness of the West Sak and Ugnu formations averages 1,050 ft. These two formations are oil-bearing primarily in the Kuparuk River and Milne Point units, where they occur at depths ranging from 2,000 to 4,500 ft (Werner, 1984). West Sak, at a depth of 2,000 to 4,500 ft, is fine to fine-grained sand with interbedded mudstone and claystone deposited as fluvial-deltaic sands. Its porosity averages less than 20%, and the permeability is 10 to 140 millidarcies. It contains intermediate to slightly heavy oil of 50 to 3,000 cP (14°-22.5° API gravity) at a reservoir temperature of 45°-100° F. Properties of West Sak heavy crude oil are listed in Table 1. West Sak heavy oil is believed to have the same source as that of the deeper Kuparuk, Sadlerochit and Lisburne light oil reservoirs, but it has been biodegraded (Sharma, 1990), especially at shallower depths.

Ugnu, at a depth of 500 ft above West Sak, is unconsolidated sand. Its average porosity is 25%, and the permeability is very high. It contains viscous heavy oil – that can be classified as

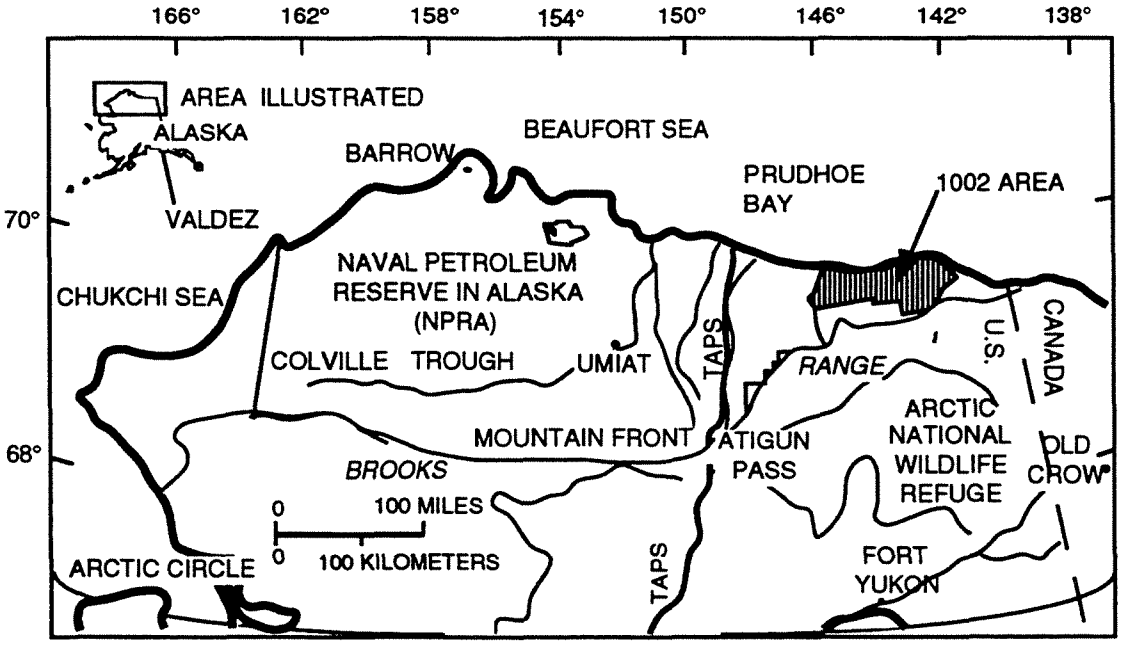

FIGURE 4. - Map of northern Alaska showing major geographic features and locations of Naval Petroleum Reserve Alaska (NPRA), Arctic National Wildlife Refuge (ANWR), and the TransAlaska Pipeline System (TAPS) – (Thomas et al., 1987).

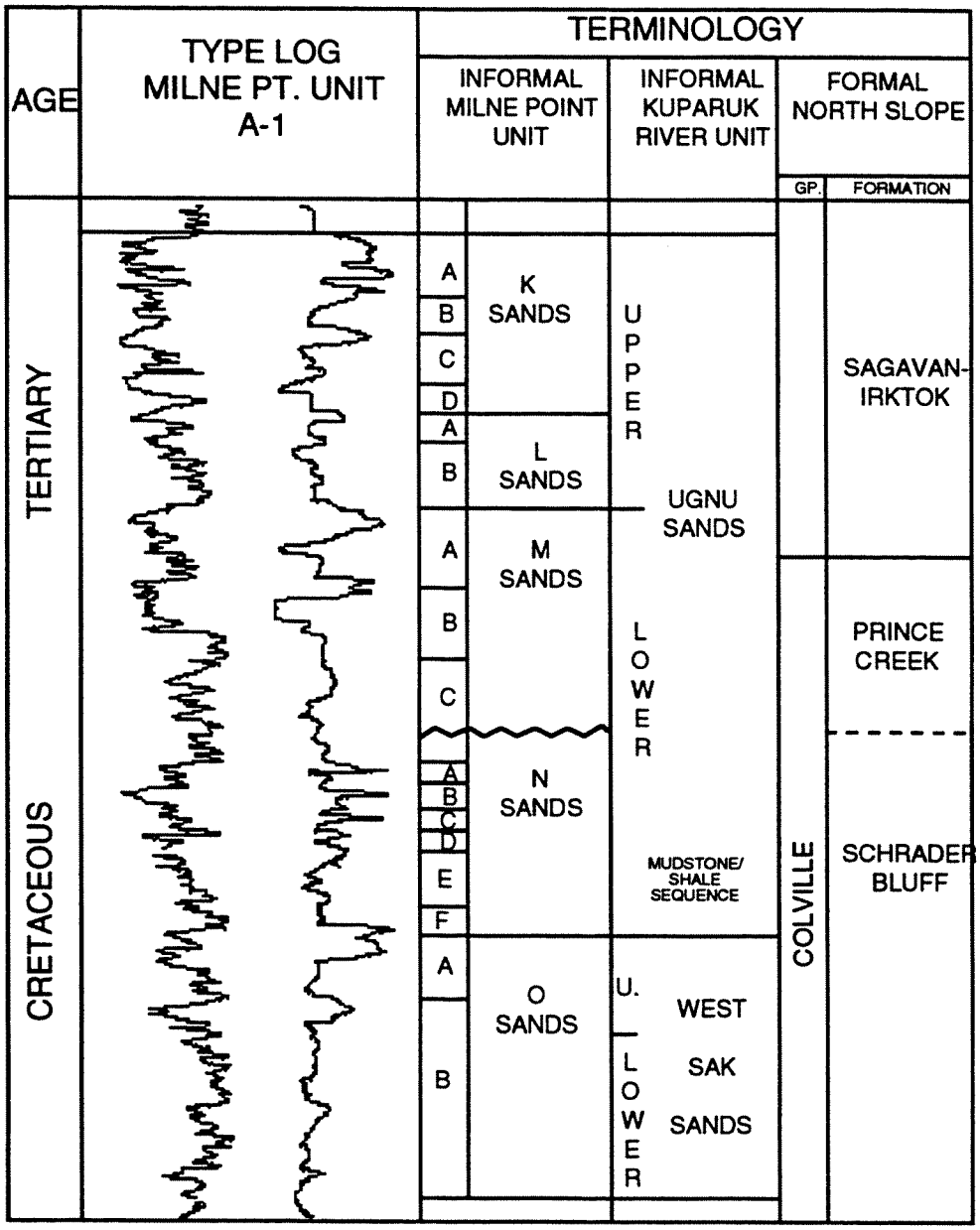

FIGURE 5. - Composite well logs and formation nomenclature for North Slope fields(Werner, 1984).

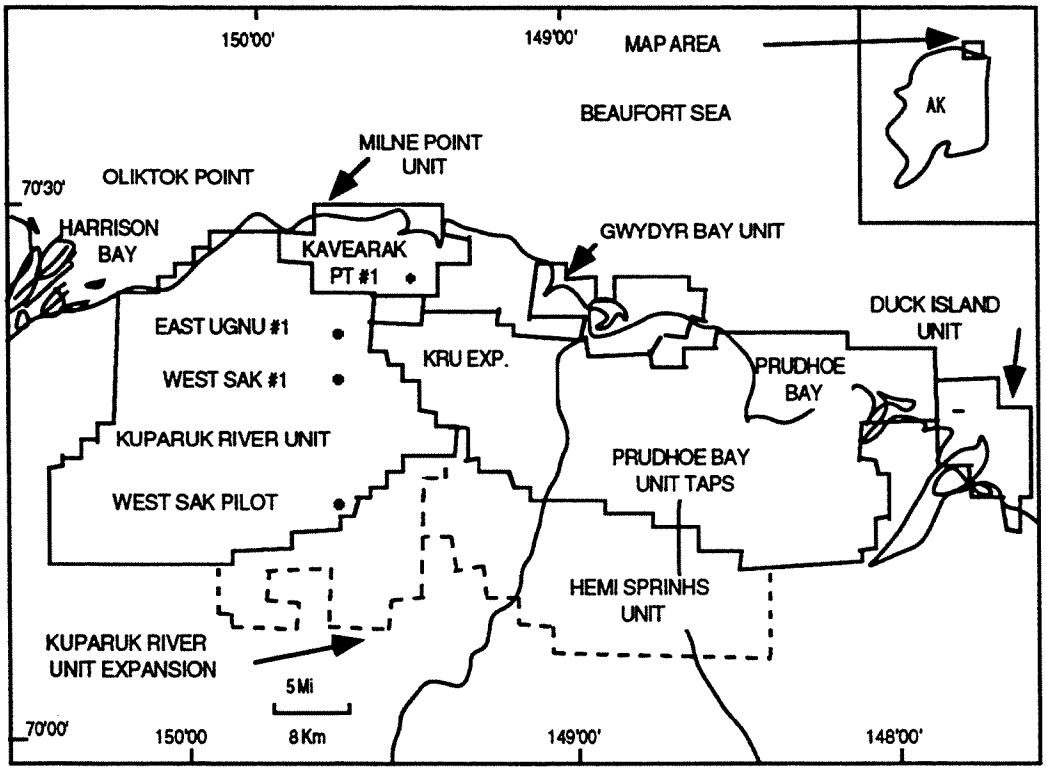

FIGURE 6. - Alaskan North Slope Index Map (Werner, 1984).

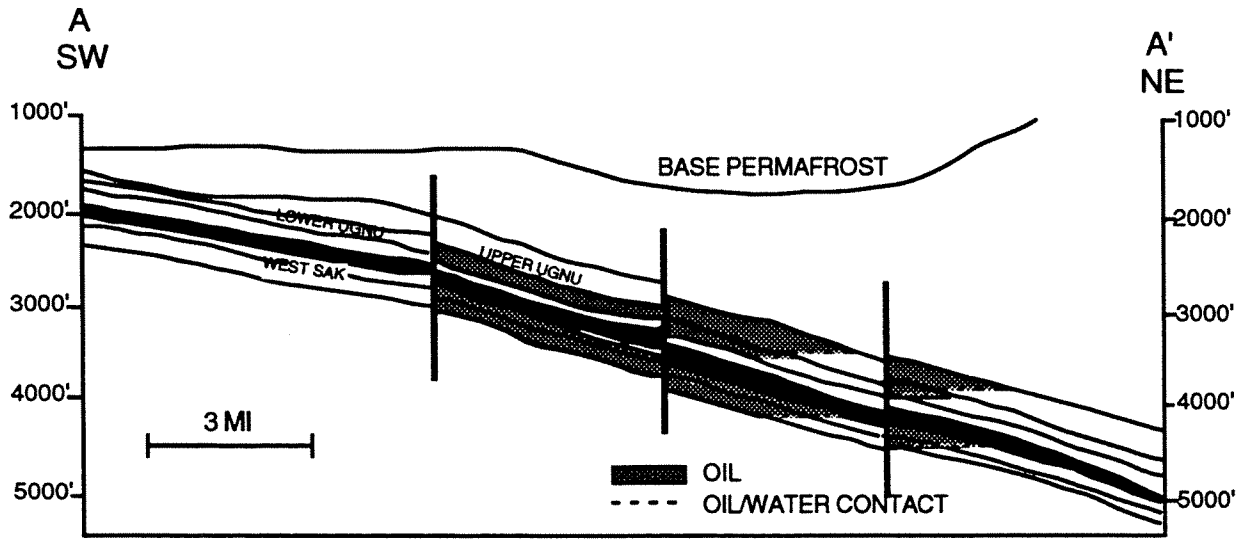

FIGURE 7. - Northern Kuparuk River Unit generalized structure showing faulting – (Werner, 1984).

TABLE 1

West Sak Reservoir and Crude Oil Properties [After Hallam et al., 1991]

Sampling depth, ft	4603
Reservoir temperature, °F	80
Bubble point pressure, psi	1,690
Oil gravity, °API	19.2
Oil density at bubble point pressure, g/cm^3	0.9022
Solution GOR at bubble point pressure, scf/STB	210
Viscosity at bubble point pressure and 80 °F, cP	35.4
Oil FVF, bbl/STB	1.069
Gas Composition, % methane	98
Mol. Wt. of C_{21+} Fraction	455

COMPOSITION (mol %): N_2: 0.03; CO_2: 0.02; C_1: 38.33; C_2: 0.86; C_3: 0.36; C_4: 0.18; C_5: 0.06; C_6: 0.20; C_7: 0.02; C_8: 0.01; C_9: 0.82; C_{10}: 1.50; C_{11}: 1.72; C_{12}: 0.35; C_{13}: 0.50; C_{14}: 0.80; C_{15}: 0.94; C_{16}: 0.80; C_{17}: 0.57; C_{18}: 1.80; C_{19}: 2.47; C_{20}: 2.84; C_{21}: 38.82

bitumen or extra heavy oil – of several thousand cP viscosity (7° to 12° API gravity) at a reservoir temperature range of slightly lower than 45° to 65°. The Ugnu crude oil properties are listed in Table 2. The oil-bearing zone of Ugnu has a width of about 2 miles and a length of about 9 miles and extends east-west. The average oil saturation within the best portions of the reservoir is between 66 and 72%. The structure dips from southwest to northeast at about 2 degrees (Hallam et al., 1991).

A considerable volume of tar deposit is reported to underlie the light- to heavy-oil sands in Endicott field, which is mostly offshore. The base of this tar zone is at a depth of approximately 10,403 ft and the top is at 10,395 ft. The 18° API heavy oil, which overlies the tar zone, has a reservoir temperature of 200° to 225° F. The 1002 area in ANWR, located east of Kuparuk (Fig. 4), is reported to have a 95% probability of 1.2 to 4.8 billion bbl, and the mean probability of 3.45 to 13.8 billion bbl undiscovered crude oil (Thomas et al, 1991). The estimates differ within each probability range because of independent estimations by various sources. How much of that oil is heavy is not known as the area is essentially undrilled. The area is not yet available for exploration to the industry because of its protective status as a wildlife refuge, nor does it appear to be open for drilling in the near future.

TABLE 2

Ugnu Reservoir and Crude Oil Properties [After Hornbrook et al., 1991]

Depth, ft	2400-3000
Reservoir temperature, ^{o}F	45-65
Oil gravity, ^{o}API	7.1 to 11.5
Solution GOR at 60 ^{o}F and 1328 psi pressure, scf/STB	120-130
Oil viscosity, cP	> 60,000
Net Pay, ft	75
Net/Gross	0.6-0.83
Porosity	0.34-0.37
Oil saturation	0.66-0.72
Reservoir pressure (psi)	1330

Elemental Analysis (%): Carbon: 85.1; Hydrogen: 10.9; Nitrogen: 0.5; Oxygen: 1.8; Sulfur: 1.7
SARA ANALYSIS (%): Saturates: 10.6; Aromatics: 53.0; Resin I: 30.4; Resin II: 2.3; Asphaltene: 3.6

Size of Heavy Oil Deposits in Alaska

Recent estimates of resource including that of the Fisher et al., 1992, do not differentiate oil by gravity, and heavy oil accumulations in Alaska have been less clearly defined than that of light oil, such as Prudhoe Bay. With the small volume of data acquired and it's limited disclosure to the public, the total heavy oil deposits in Alaska have been estimated (Sharma, August 1990) to be as high as 40 billion bbl, and 15 to 20 billion bbl of this oil is in West Sak reservoir alone, making it the largest known heavy oil accumulation in the United States. Ugnu is a giant accumulation, with 6.5 billion bbl in upper Ugnu and 8.5 billion bbl in lower Ugnu. Approximately 0.43 billion bbl of bitumen (or extra heavy oil) is reported to be in Endicott, but it is currently considered immobile (Sharma, August 1990). Figure 8 shows the relative importance of heavy and light oils in the North Slope of Alaska.

According to these estimates, the size of heavy oil deposits is about the same as the size of known light oil deposits in Alaska, which is reported to be 33 billion bbl. Later studies tend to reduce these estimates. For example, one estimate puts the Ugnu deposits at 6 billion barrels, of which only 2 billion bbl were determined to be potentially exploitable (Hallam et al., 1991). Due to technical and operational difficulties, the recovery factor for AHO is believed to be very low, as little as 5% by some estimates. The spread in various estimates, quite understandably, is caused by the scarcity of data.

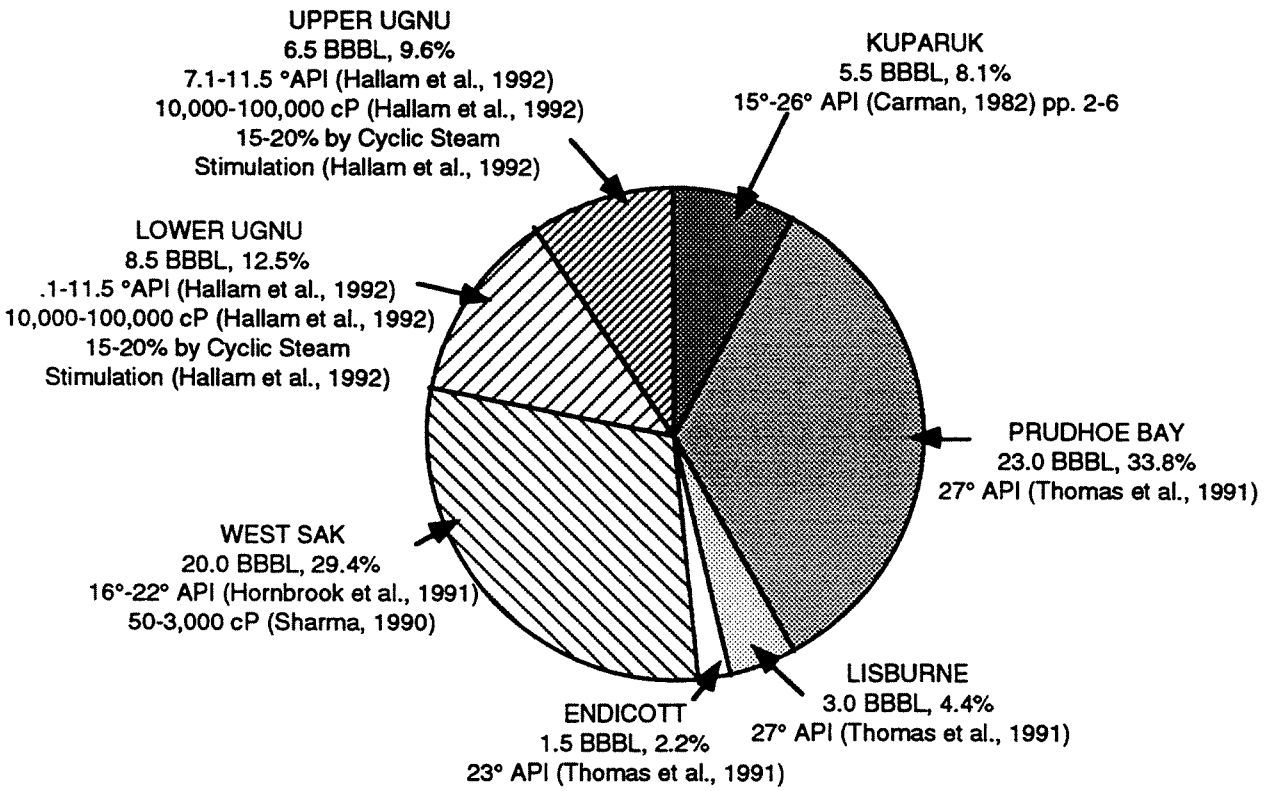

FIGURE 8. - The total estimated original oil-in-place in the North Slope of Alaska – (Kamath and Sharma, 1986) with API gravity and proposed recovery factors from reference listed.

Table 3 shows the past cumulative oil production. The only currently producing heavy oil reservoir is Schrader Bluff (Milne Point field), which has the same source of oil as that of West Sak. Conoco was producing 17° API oil through nine wells in May 1992. The highest producing well yielded 16,239 bbl oil per month (BOPM) (Alaskan Oil and Gas Commission, 1992). Other high yielding wells, in order, were producing approximately 15,000; 13,000; and 12,600 BOPM. Conoco performed an inverted 9-spot injectivity test, but the results have not been disclosed.

There are several smaller heavy oil reservoirs offshore which are not currently developed because their size is smaller than the offshore economic cut-off limit (e.g., Sandpiper – no estimate, 1 well drilled; and Seal Island/North Star – recoverable oil estimated to be 150 million bbl, 50 miles NW of Prudhoe Bay).

Geological Structure of Heavy Oil Reservoirs in Alaska

The geology of West Sak and Ugnu reservoirs, which contain most of the heavy oil, is described below and shown in Figs. 9 through 12. The tar sands underlying Endicott light oil fields are not included because they are considered immobile using current technology.

TABLE 3

Estimates Of Alaskan North Slope Oil Resources (million barrels) [After Sharma, 1990]

Field	Original Oil-in-place[1]	Cum. oil produced[2]	Recoverable reserves[3]	Remaining oil
Prudhoe Bay	23,000	6,605	4,700	11,695
Lisburne	3,000	49	150	2,801
Endicott	1,500	86	280	1,134
Kuparuk	5,500	616	885	3,999
West Sak	20,000	0	0	20,000
Lower Ugnu	8,500	0	0	8,500
Milne Point		9	50	
Point McIntyre		0	200	
Total	68,000	7,365	6,265	54,629

Source:
[1] Kamath and Sharma, 1986
[2] Annual Production Statistics, Alaska Oil and Gas Conservation Commission. As of 12/31/89
[3] Gould et al., Alaska Update: September 1988 - January 1990. As of 12/31/89

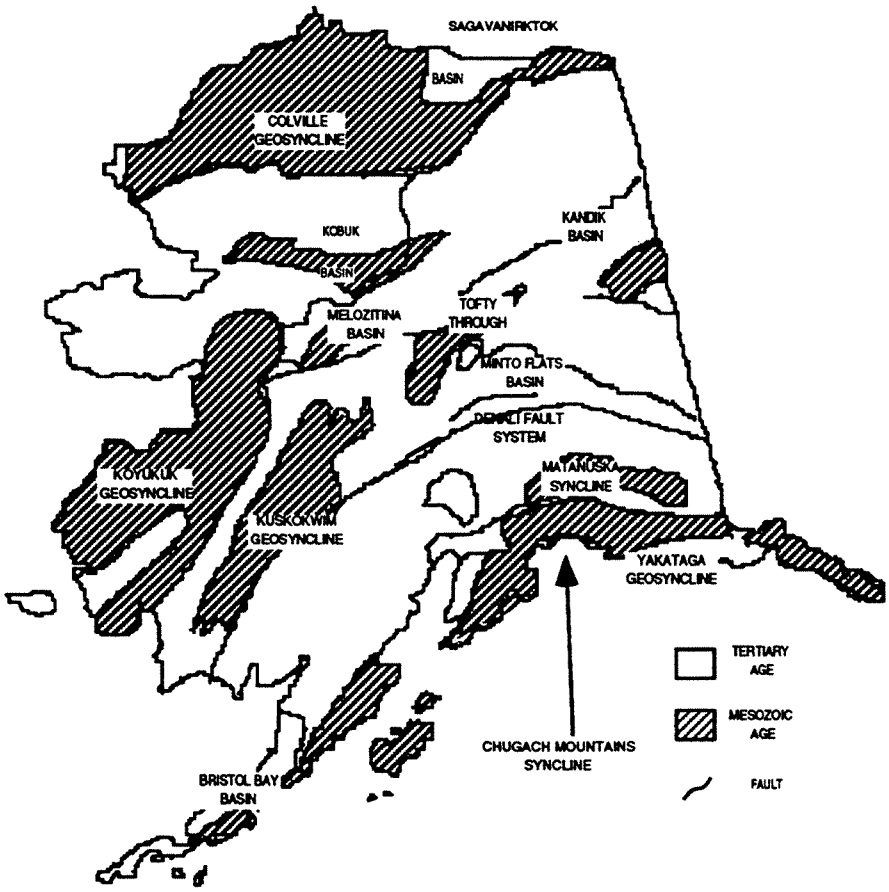

FIGURE 9. - Major depositional basins in Alaska.

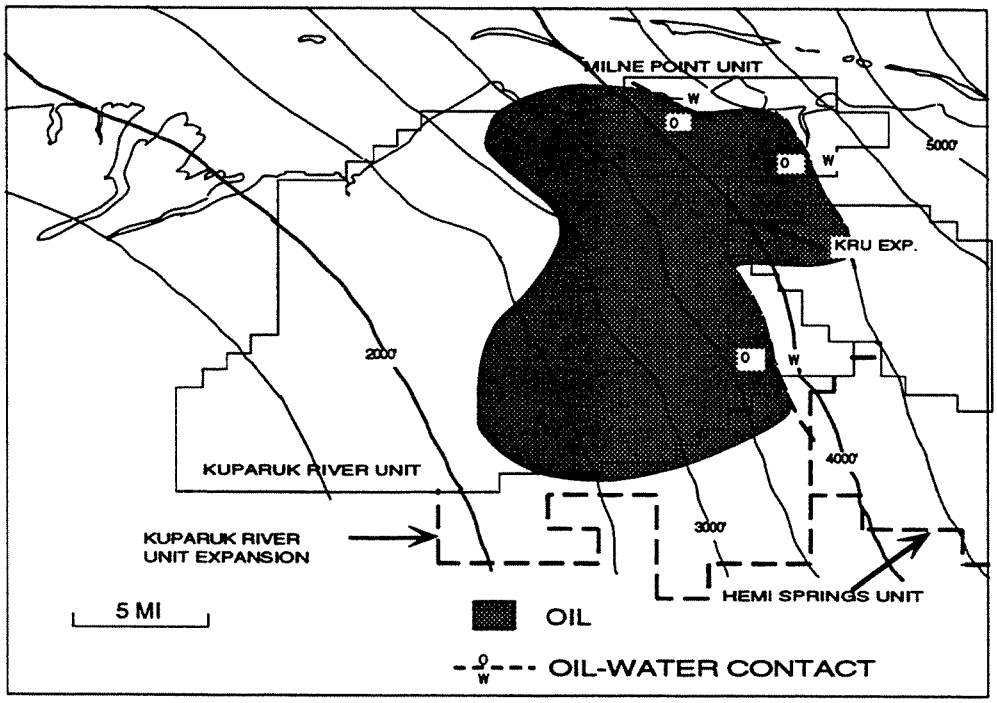

FIGURE 10. - Structure on top of West Sak sands – (Werner, 1984).

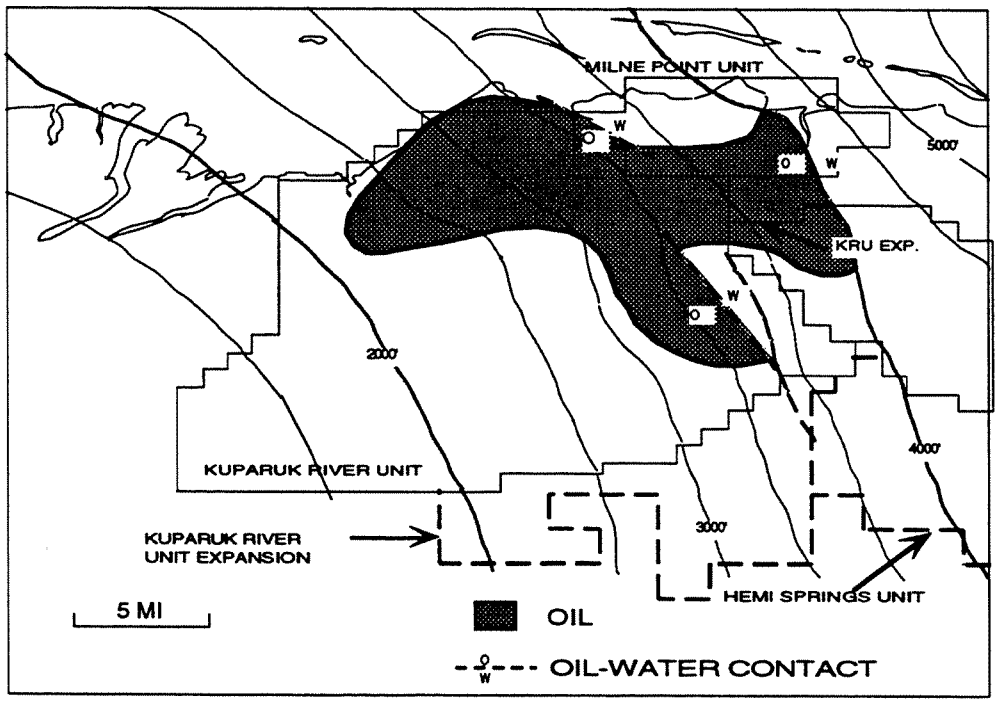

FIGURE 11. - Structure on top of Lower Ugnu sands. Oil-bearing portion is stippled – (Werner, 1984).

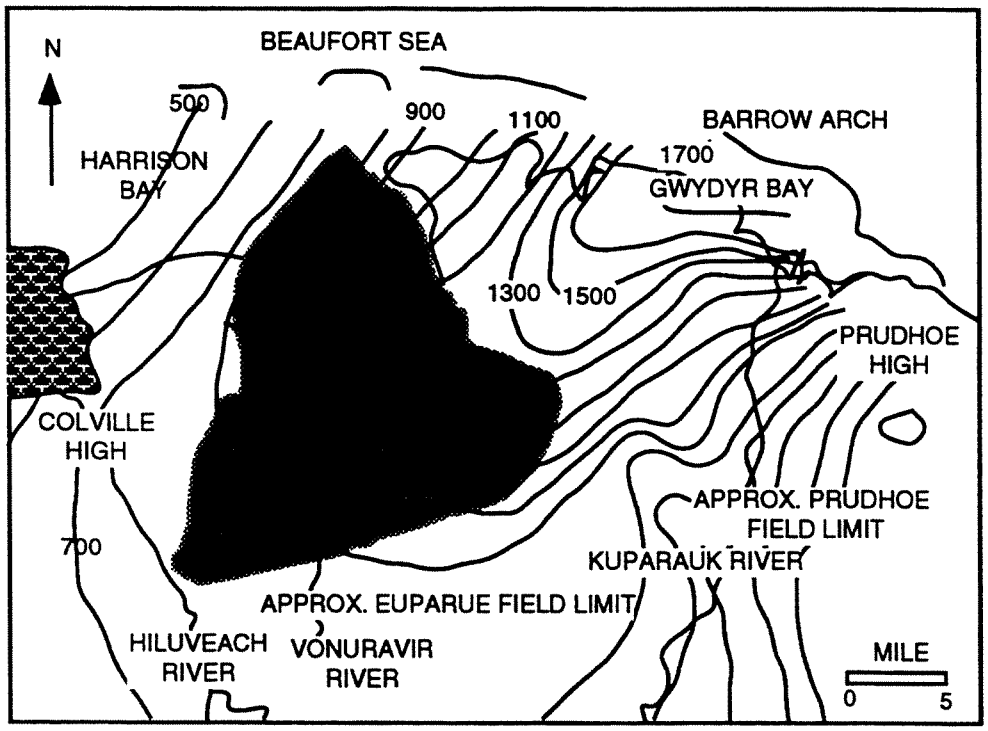

FIGURE 12. - Structure on top of Upper Ugnu sands. Oil bearing portion is stippled.

Ugnu:

The Ugnu sands are predominantly fine-to medium-grained, well-sorted quartz and unconsolidated sands. Core data show porosity from 30 to 35% and horizontal air permeability from 200 to 3,000 millidarcies (Werner, 1984). The reservoir temperature varies from 45° to 65° F. The reservoir pressure gradient is estimated to be 0.446 psi/ft, and the fracture gradient is 0.71 psi/ft, with Poisson's ratio determined to be 0.37 (Hallam et al., 1991).

Ugnu sands are divided into upper and lower members. The lower Ugnu is 250 to 350 ft thick with three to five major sand beds, which increase in thickness and lateral continuity, generally to the Northeast. The lower Ugnu is separated from the underlying West Sak sands by a regionally extensive mudstone that ranges from 100 to 150 ft thick in the Kuparuk area (Fig. 7). The uppermost beds of the lower Ugnu are more laterally extensive and thicker. They are interpreted to be fluvial-dominated delta deposits (delta plain and fluvial deposits) and are believed to be the most promising oil productive region in the Ugnu sands.

The upper Ugnu has an average thickness of 300 ft in the Kuparuk area and consists of very fine- to medium-grained sands with interbedded siltstone, mudstone, and coal. It is composed of five to seven major sands, each having an average thickness of 20 to 30 ft. Hallam et al. (1991) divided the Ugnu into zones A through C (Fig. 13), with zone B being the delta top and the

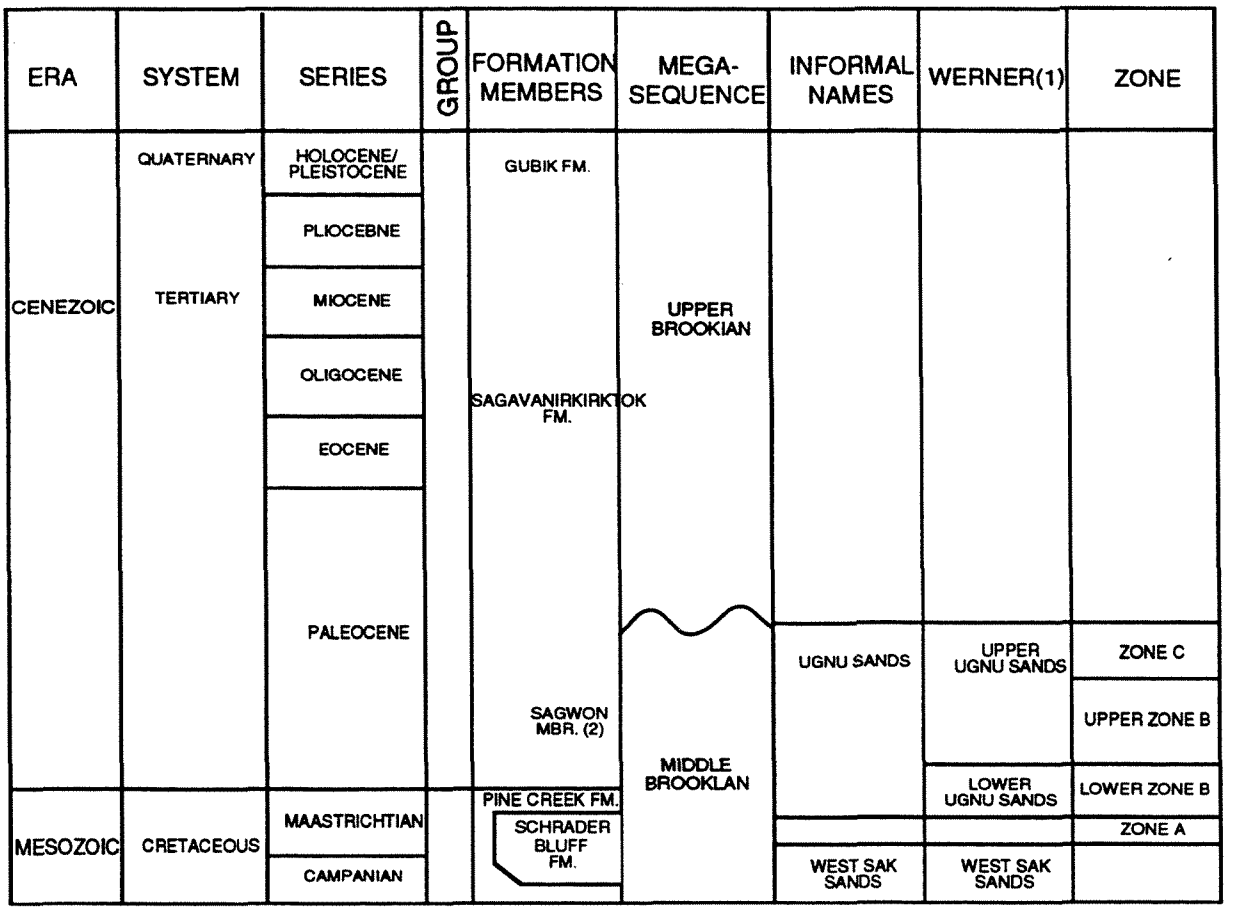

FIGURE 13. - Geologic column of North Slope of Alaska.

principal bitumen bearing unit with an estimated OOIP of > 6 billion bbl. Previous estimates (Werner, 1984) placed Ugnu reserves at 11 to 19 billion bbl. Hallam's paper refers to the data from two wells — one drilled in 1983 and one in 1989 — in which injection was tested. Out of the revised 6 billion bbl OOIP estimated by Hallam et al., 2.5 billion bbl met their screening criteria, but only 2 billion bbl was considered "potentially exploitable." The excluded 0.5 billion bbl oil had physical constraints such as proximity to the faults or overlying temperature-sensitive drill sites.

West Sak:

The West Sak sands are the most likely future candidates for heavy oil production on the North Slope. With API gravity of 16 to 22 degrees, and in-place viscosity of as low as 35.4 cP at 80° F (Hornbrook et al., 1989), West Sak crude should be easier to produce, transport, and market than Ugnu heavy oil.

The West Sak (Fig. 10) thins from 450 ft in the Southwest to 200 ft in the Northeast, with an average thickness of 300 ft in the Kuparuk area (Werner, 1984). It consists of very fine- to fine-

grained sandstone and silty sandstone with interbedded siltstone and mudstone. Upper and lower units are recognized consisting in part of amalgamated sand-rich units ranging up to 10 ft in thickness, with the lower member consisting of thin-bedded sands ranging from 0.2 to 5 ft thick. Sands in the lower member may be laterally continuous for up to 3 to 5 miles. The upper West Sak consists of two distinct and laterally extensive sands, each of which is up to 25 to 40 ft thick and consists of individual beds 0.5 to 10 ft in thickness. The West Sak represents a transition from inner shelf deposition for the lower West Sak to shallow marine or delta front deposition for the upper West Sak. The estimated resource for the West Sak ranges from 15 to 25 billion bbl (Hornbrook et al., 1989). However, a poor recovery factor is expected — as low as 5% — that reduces the reserve to 310 million barrels (Alaska Dept. of Natural Resources, 1992). The reserve is defined as the economically recoverable portion of a resource at current market conditions.

Technical Challenges in the Recovery of Heavy Oil from Alaska

Although Alaskan heavy oil deposits are almost as large as those of light oil deposits in Alaska, their recovery is significantly more difficult for both technical and economical reasons. These heavy oils are in relatively shallower sands, around 4,000 ft below the surface. The sand at these depths is unusually cold, 45° to 100° F, because of the 2,000 ft of overlying sub-freezing permafrost. The cold temperatures and the heat-sensitive structural integrity of permafrost pose some uncommon challenges, as discussed in the following paragraphs. Some of these heavy oils (e.g., Endicott, 429 million bbl of bitumen is currently considered immobile) are too viscous to be considered economically recoverable.

Kuparuk reservoirs, light as well as heavy oil, are characterized as being thin and as having areally broad pays, no gas-caps, and low-pressure reservoirs, thus requiring artificial lift. The heavy oil reservoirs, since they occur in shallower formations, also suffer from proximity to the permafrost that results in reduced reservoir temperatures and increased viscosity (*Oil & Gas J.*, March 1983). Steamflooding, the first choice for producing heavy high-viscosity crude, requires careful scrutiny because of the possibility of melting the overlying permafrost layers, resulting in loss of surface production facilities. If the steam is injected at the surface instead of sand face using downhole steam generators, adequate insulation of the tubings from the surface to the sand face is required to avoid melting or thawing the surrounding permafrost. Downhole steam generators have never been shown to be a viable technology even after hundreds of millions of dollars of research and development in the 1970s and 1980s. Melting causes the permafrost to compact and subside, subjecting the well casing to strains that may lead to failure (Hallam et al., 1991). Injecting steam at the surface would require adequate insulation because of economic reasons, i.e., to save the extensive heat loss at the subzero temperatures in Alaska. If steam is injected downhole, it must be at least below the level of the permafrost. Sand production from West Sak is a serious problem because sands are unconsolidated, as experienced by Conoco in the

nearby Milne Point. Nevertheless, Conoco is currently producing an average of 300 BOPD per well from Shrader Bluff (which is essentially Milne Point), implying that handling such problems are costly but not prohibitive.

The primary recovery factor from these heavy oil deposits is estimated to 5%, (Sullivan, 1991) which is only a small fraction (1/4th) of the recovery factor at the light-oil Prudhoe Bay deposits. The reasons could be the heterogeneous geological structures of the formations, the higher viscosities of oil at the low reservoir temperature, or absence of natural pressure-maintenance mechanisms such as a gas-cap or waterdrive. These conditions may require that secondary (i.e., pressure maintenance) — and soon after — tertiary oil recovery techniques be employed very early.

The 5% recovery factor reported in the literature appears to be low despite the geological and geophysical abnormalities. It is possible that the 5% recovery estimate came from considering the percentage of recoverable oil from the entire reservoir. In reality, though, only the most promising sections of these reservoirs will be developed, such as the hotter and higher-°API eastern sections of West Sak, which has a target recovery factor of > 20% with waterflooding and even higher with steam or CO_2. If such preferential development is assumed in an economic model, it will likely lower the threshold oil price for economic viability, perhaps as low as $20 per barrel (based upon current posted oil price and estimated freight). It would not, however, affect the overall reserve estimates.

Applications of EOR techniques in these reservoirs are also likely to be challenging. Generally, thermal and miscible recovery methods have shown to be economically feasible for heavy oil reservoirs. Both fireflooding (in situ combustion) and steamflooding have to be carefully examined to eliminate any danger of melting the permafrost. Steamflooding, the most common heavy oil recovery technique, suffers from extensive heat losses to surrounding layers because of the small thicknesses of the oil-bearing sands and because of the lower-than-normal temperatures of the surrounding formations. In popular miscible gas displacement techniques, CO_2 has shown in the laboratory to experience problems in achieving dynamic miscibility (Sharma, June 90). The current heavy crude price outlook may even require that unconventional techniques promising lower operating cost and/or higher recovery factor be explored, such as, e.g., *in situ* combustion.

Environmental Constraints

Persistent pollution problems on the North Slope have been reported in a National Wildlife Federation study (*Oil & Gas J.*, Feb. 1, 1988). One of the claims made in the study was that reserve pits, 250 in number, each containing as much as 13 million gallons of used drilling mud and associated waste, constitute a risk of toxic pollution on the North Slope. Analyses of these wastes are said to show heavy metals, hydrocarbons, and additives. The study also states that

Alaska's Department of Environmental Conservation recorded 953 spills on the North Slope (during 1985-86) involving 4,600 bbl of oil and other liquids.

The financial liabilities of oil spills are also enormous. The Exxon Valdez spill on March 24, 1989, has had a huge impact on oil companies operating on the North Slope. The final cost of cleanup may be in hundreds of millions of dollars. British Petroleum shelved an $80 million development project (*Oil & Gas J.*, Oct. 1, 1990) because of changes in Alaska's severance tax calculations approved after the Valdez spill. A spill-readiness team, capable of handling a 1.8-million bbl spill in Prince William Sound, may cost the petroleum industry $58.5 million per year, according to the Alaska Oil Spill Commission (*World Oil*, May 1990). In spite of these well publicized problems, the petroleum industry's environmental record has been good in this area.

Transportation

The capacity to increase North Slope production by adding heavy oil production is severely hampered by transportation problems. Marketing oil from these fields requires transportation to the lower 48 states. Existing facilities (Fig. 14) include TransAlaska-Alaska pipeline, the main pipeline from Prudhoe Bay to the lower 48 states, and a branch pipeline from Kuparuk River fields to the TAP. Tests have shown that the TransAlaska-Alaska Pipeline is capable of a throughput of more than 2 million barrels/day using drag reducing agents (Williams, 1990). TAPS has the additional capacity, but the pipeline from Kuparuk to TAP is running full (1991), which is perhaps the reason for delaying the further development of heavy oil from West Sak, and possibly other reservoirs as well.

West Sak crude appears to be amenable to pipeline flow with an average gravity of 19.2° API and an average viscosity of 35.4 cP at 80° F (Hornbrook et al., 1989), whereas Ugnu crude, having viscosities of 60,000 to 10,000,000 cP at reservoir conditions, is seemingly difficult to transport through the existing pipelines in a cost effective manner (Hallam, 1991). This constraint adds to the difficulties in economic production of Ugnu reservoirs and makes it unlikely that Ugnu will be developed now or in the near future.

Alternative to ANS crude oil transport through TAP were considered early in the development of North Slope fields and the design of TAP. A consortium of companies determined the feasibility of constructing a major refinery in Alaska and shipping the refined oil south instead of crude (Schmidt, 1991). The proposal was deemed uneconomical because of harsh climate, potential for environmental problems (disposal of heavy ends and metals), transport of batches of product over a single pipeline and then different tankers for different products, large tank farm complex and anticipated high operating costs. Since the refining of 28° API gravity crude in large volumes was not justifiable, it is unlikely that the construction of upgraders to process heavier oil may be feasible. Some companies have reanalyzed this scenario in recent years, but the TAP remains to be the only feasible option thus far.

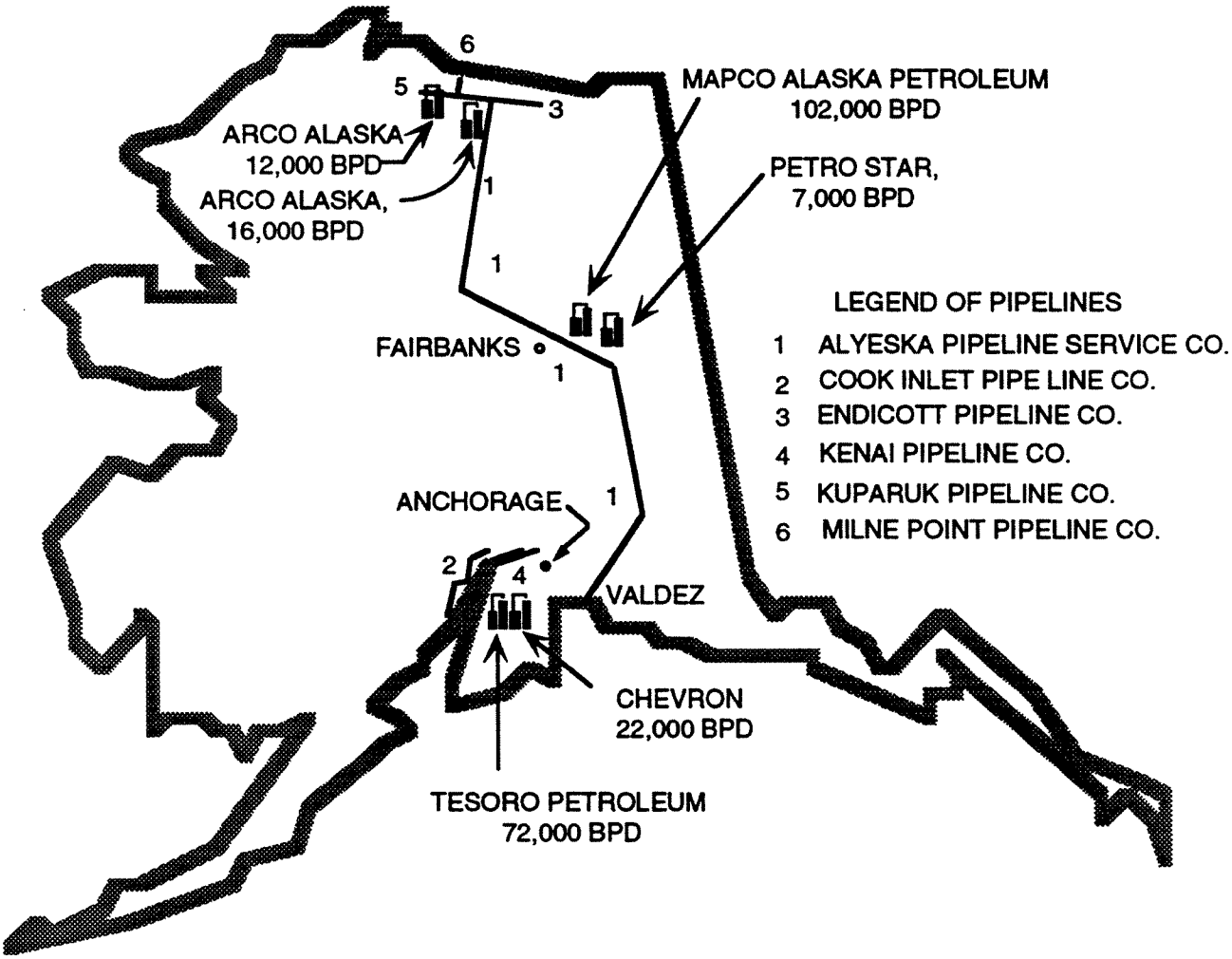

FIGURE 14. - Location of existing pipelines and refineries in Alaska.

Unless significant new large oil fields are developed on the North Slope, the declining production from the existing reservoirs will result in the usage of TAP pipeline falling below its 300,000 b/d economic threshold by the year 2009 (Fossil Energy Review, Jan.-Mar 1991), at which point the pipeline is likely to be shut down. Prudhoe Bay oil field passed its production peak in 1986. Production is expected to decline about 10% per year over the next five years (Fossil Energy Review, Jan.-Mar 1991). The need to keep this pipeline flowing may be an incentive to develop some of these otherwise difficult heavy oil reservoirs and open exploration of adjacent known structures which may contain significant light oil.

Economic Considerations

With resources in the billions of barrels, the incentive to produce North Slope heavy crude would appear to be very high; however, production and transportation expenses are also extremely high. ARCO Alaska was once prepared to spend more than 7 billion dollars over 10 years to raise its proven North Slope reserves by almost 900 million barrels by 1997 (*Oil & Gas J.*, April 1988).

They assumed reasonable oil prices and stable taxes. In the first phase, the West Sak field development was scheduled as part of this expenditure.

As early as 1982, ARCO tied production of it's North Slope heavy oil to state tax policies (*Oil & Gas J.*, Mar. 22, 1982). In 1989, Alaska's legislature voted to reduce the tax incentive programs, the Economic Limit Factor (ELF), originally created to promote additional drilling in the North Slope's oil fields (Enhanced Recovery Week, Aug. 7, 1989). This move, retroactive from Jan. 1, 1989, was claimed to cost operators up to $100 million. Operators claim that ELF provided the impetus for the startup of many economically marginal projects. ARCO Alaska announced that it would forego its long awaited West Sak field development. Interestingly, this occurred after ARCO and it's West Sak partners were reported to have spent more than $225 million in engineering and research to design the recovery project (Enhanced Recovery Week, Jun. 26 1989). It is not clear whether the decision to cancel the planned development was based solely on the repeal of the ELF incentive or upon other factors such as non-availability of pipeline capacity at that time or revised reserve estimates. The current revised recoverable reserve estimate of West Sak, the most viable of the heavy oil deposits, is 310 million barrels (Dept. of Natural Resources, 1992). This lower or reserve estimate from a huge resource of 15-25 billion bbl represents the expectation of a very low recovery factor.

The technical challenges discussed in the earlier sections of this report will no doubt add costs to recovering AHO. Some of the cost factors making heavy oil production in Alaska less lucrative include finding an appropriate production technique, higher cost of EOR applications, increased risk factor if a non-conventional technique is adopted, and lower market price at the wellhead due to the oil being heavier and remotely located. These costs are in addition to the already high cost of operating in Alaska due to the remoteness and harsh Arctic climate.

Several factors, on the other hand, are in favor of developing these deposits. One is the huge size of these deposits. Some other possible factors are: the need to pump more oil through TAP in order to meet the minimum requirement for its effective operation; the possibility of sharing existing facilities, field equipment, and other resources at tremendously lower costs; and the potential for future tax incentives. Most operators have publicly expressed — and backed up by their actions — that the development of AHO on its own economic merit, is not feasible under the current market conditions and statutory marketing requirements. They have sought tax incentives and pressed for relaxation of the compliance standards of various regulations.

The apparent unwillingness of current operators to pursue development does not mean an absolute non feasibility of developing these resources. If there were not a sizable resource base, major oil companies would not have undertaken production studies or studies on oil transport (e.g., mixing heavy oil with the current 27° API ANS oil). Major oil companies have traditionally sought capital-intensive projects with a risk-adjusted > 10-20% annual rate of return on

investment. These major oil companies have to prioritize their budgeted capital investment in world-wide opportunities by postponing less lucrative projects. Technically, the special challenges expected in developing these reservoirs are well within the capabilities of the petroleum industry. These resources may practically be considered off-limits (because of their capital-intensive nature) to the non-major oil companies that are usually willing to venture under less favorable conditions.

Alternative ways to decrease the dependence on foreign oil should be considered versus stimulating production with incentives. For example, the refinery capacity for processing domestic heavy oil may be increased in order to reduce the dependence on imported oil. Such an action may have its own difficulties, and may not be feasible or economical. Imports of heavy oil from Canada to the upper Midwest and from Mexico or Venezuela to the Gulf Coast are tied to low crude prices. Besides, these nations are our long-term dependable suppliers, with whom the U.S. is trying to build a hemispheric energy agreement. The merit of curtailing imports from these countries needs to be carefully analyzed. It may also be impractical since some U.S. refineries are owned by the subsidiaries of major oil companies of these countries.

Possible Methods of Recovery of Heavy Oil from Alaska

West Sak and possibly Ugnu are heavy oil reservoirs that can be considered to be likely candidates for early EOR applications because of their low recovery factor. The presence of large reserves of natural gas, approximately 27 trillion scf (Sharma, 1988), of which 12.5% is CO_2, provides an opportunity for EOR of the North Slope's heavy oil. One important consideration is that the gas has to be pipelined for use in these heavy oil reservoirs, most likely for the West Sak. No immediate plans are speculated by the major oil companies on miscible flooding the West Sak and Ugnu sands, and no such plan was made at the time of field development. Conoco had originally planned developing the Ugnu/West Sak heavy oil, and is believed to have acquired some surface equipment (Tom Reid, memo 7-29-92). With no ready market for the natural gas, ARCO, BP, Chevron, Exxon, Mobil and Phillips have announced they are investing 1.1 billion dollars to construct a natural gas handling plant. The plant, scheduled to be completed in 1995, will be operated by ARCO. The project, designed to stimulate declining production and handling produced natural gas, is expected to increase oil production from the North Slope by 100,000 BOPD. Most of the recovered gas will be reinjected (*World Oil*, 1990) to help maintain production. Prudhoe Bay Field (Sadlerochit reservoir) and then the Kuparuk Field (Kuparuk sands) are likely to be the major utilizers of this gas. The Schrader Bluff Pool of the Milne Point Unit is also a possible future candidate.

Laboratory Studies:

There are more laboratory and simulation studies in the public literature than reservoir or oil information. In the context that these are laboratory studies, which show potential for heavy oil

production, they are limited in scope. They often look at one aspect which is removed from some of the overwhelming technical, environmental and economic constraints that exist including competition on the world market for investment capital.

Due to the high viscosities resulting from the relatively low reservoir temperatures (average between 45° and 100° F) of these shallow heavy oil reservoirs overlain by permafrost, thermal and miscible methods have been seriously considered and laboratory tested as discussed below.

Miscible Displacement:

The feasibility of miscible methods for recovering West Sak oil was tested in a slim tube packed with Ottawa sands (Sharma, June 1990). Use of slim tube testing is a standard practice for estimating minimum miscibility pressure (MMP) of miscible systems. CO_2, the first choice of many miscible processes these days, was unable to develop dynamic miscibility with West Sak oil at reservoir conditions. N-Butane was found to be first contact miscible with West Sak oil and recovered as much as 80% of oil-in-place. A 1:4.7 solvent mixture of Natural-Gas-Liquids: Prudhoe Bay Gas also yielded similar recovery. Introduction of water to the system did not seem to affect miscibility, but the precipitation of asphaltene was mentioned to be a problem.

Steam and Steam-Solvent Displacement:

A study (Hornbrook et al., 1989) conducted at the University of Alaska, Fairbanks, indicated that the recovery of West Sak crude may be enhanced by adding CO_2 to steam injection. Increases in ultimate recovery and recovery rate as well as a reduction in the required heat inputs were some of the results of this study. The tests also indicated that there is an optimum steam/CO_2 concentration – 3:1 molar ratio – yielding a 12.8% increase in recovery.

The CO_2-steam process was tested (Sharma, June 1990) in a 2" diameter sandpack of 4' length containing fluid-loss-control sand (Oklahoma #1) saturated with a relatively lower viscosity West Sak oil (34.5 cP). Steamflooding by itself recovered 77% of oil after six pore volumes (cold water equivalent, CWE) of steam injection. Oil recovery was significantly lower when the sandpack also contained gas when the test started. With an initial gas saturation of 11.2%, only 53% oil was recovered. Steam by passing, as a consequence of gas presence, was mentioned as a possible cause for the lower recovery.

Addition of N_2 with steam increased oil recovery by 8% over steam-only injection. Methane with steam increased recovery over steam-only run by 13.4%. Most spectacular results were obtained with CO_2 simultaneously injected with steam, recovering 92% of oil after similar throughput as in other runs. Rate of recovery was also faster when one of the gases — CO_2, N_2 and methane — were simultaneously injected with steam (Sharma, June 1990). It is not clear whether the presence of these gases affected the precipitation of asphaltene as they did for the miscible displacement, or any other problems were noticed.

An economic model study was performed for steam injection. Some of the assumptions in their model are listed in Table 4. It appears from their report that the higher performing CO_2-steam process was not evaluated. This simplified model, which did not consider the effects of reservoir heterogeneities and rock-fluid interactions, showed an oil price range of $18-25/barrel to be economic (Table 5). It appears from their report that the economic model prices and costs are based on 1988 dollars, adjusted for inflation at a rate of 4%, and include the (unrealistic) cost of transportation ($4.08/bbl) from the Kuparuk field to Valdez. In their opinion, the recovery of West Sak oil is technically feasible, but recovery remains to be proven economical because of problems posed by heterogeneities and clay swelling.

Some of the issues that need to be addressed in a more comprehensive model include reservoir heterogeneities, clay-swelling (especially at the higher temperatures encountered in steam processes), asphaltene precipitation, and wettability changes. Some economically beneficial factors, such as cost-sharing between various large projects, may also exist that could reduce the break-even price. For example, production and separator facilities that already exist in the Kuparuk field (currently used for light-oil) may become available on a cost-sharing basis for heavy oil production upon depletion of its North Slope light oil. Also, the cost of drilling per well may be lower due to the large number of wells to be drilled in the vicinity. Note that even though these resources underlie the current Kuparuk drilling pad sites, the existing wells cannot be used for heavy oil production after light oil has been produced because the casing string was not designed to withstand the strain of steam injection.

TABLE 4

Estimated Costs and Assumptions Used in Initial Sensitivity Analysis
[After Sharma, June 1990]

Cost of Drilling	= $242 per foot	(From nearby Kuparuk, 1986)
Drilling & Completion	= $2,500,000	
Surface Equipment	= $1,000,000	
Steam Generator	= $1,000,000	
Steam Quality	= 0.60 - 0.90	
Windfall Tax Limit	= $21 per barrel	
Water Cost	= $0.20 per barrel	
Gas Cost	= 0.46 per Mcf	
Inflation Factor	= 4%	(Estimated)
Economic Limit Factor	= 0.25	
Rate of Return	= 15 & 20% annually	(10-20% is industry range)
Transport Cost	= $ 4.08/barrel	(Kuparuk to TAP Valdez)
Residual Oil Saturation	= 0.12 of Pore Volume	(Assumed Propriety Info.)
Moveable Oil Saturation	= 20% of initial oil in place	(Assumed Propriety Info.)

TABLE 5

Preliminary Results Indicating Required Price Range of Oil for Economic Feasibility in West Sak
[After Sharma, June 1990]

REQUIRED PRICE OF OIL FOR 15% RATE OF RETURN

Steam Quality	1000 barrels/day	1250 barrels/day	1500 barrels/day	1750 barrels/day	2000 barrels/day
0.60	50.61	39.07	31.31	25.66	21.37
0.70	43.70	33.66	26.79	21.59	19.68
0.80	39.06	29.83	23.50	20.00	18.59
0.90	35.76	27.39	21.56	19.41	18.11

REQUIRED PRICE OF OIL FOR 20% RATE OF RETURN

Steam Quality	1000 barrels/day	1250 barrels/day	1500 barrels/day	1750 barrels/day	2000 barrels/day
0.60	58.24	45.10	36.34	29.26	25.12
0.70	50.37	38.85	31.08	25.56	21.31
0.80	45.19	34.78	27.62	22.13	19.86
0.90	41.55	32.10	25.50	20.81	19.32

Thermal recovery methods will affect permafrost layer. Hallam et al. (1991) simulation study shows such effect. At the end of the sixth steam cycles (in third year), thaw radius was approximately 10 ft at the sandface and 1 ft at the surface for a well-insulated casing. The consequences of thawing need to be carefully studied.

A recent laboratory study on the feasibility of producing the Ugnu reservoirs (Hallam et al., 1991) concluded: (1) Development would not be economic under current conditions; (2) at high temperatures, the formation undergoes a drastic reduction in permeability due to pore-throat plugging with an oil-wet material; (3) the oil has been biodegraded, with the degree of biodegradation influenced by the depth below the permafrost (shallow being more biodegraded); (4) the volume of the resource that can be recovered with thermal methods that use fracturing will be limited by the lack of continuity in the sands and shales; (5) a reservoir simulation indicated cyclic steam recoveries of 15% to 20% at a steam-oil ratio of about 5; and (6) proximity to the permafrost requires the use of insulated tubing during steam operations to prevent melting of the permafrost and subsequent casing failure. These conclusions indicate that the development of Ugnu reservoir seems unlikely in the near future unless drastic economic changes somehow take place.

CONCLUSIONS

Significant heavy oil (10° to 20° API gravity) exists in Alaska and is being produced in limited volumes, but technical, environmental, transportation and refining constraints make near term increased production unlikely because of unfavorable economics. The harsh climate for thermal (steam) recovery of AHO and the high cost of transport of a more viscous oil (through TAP to Valdez, Alaska and then by tanker to the U.S. West Coast refineries) significantly add to the production and delivery cost of a low-priced heavier oil. Economic recoverability of this oil is highly sensitive to the availability of existing facilities on a cost-sharing basis. For example, the limited capacity of the existing branch pipeline from Kuparuk River field to TAP is a likely cause for the delay of development of even the most promising heavy oil reservoir.

With the legislative constraint of having to sell ANS crude to the U.S., AHO would have to compete not only with world oil but also with heavy oil produced in California, which refines most of Alaska's current production. This has an adverse effect on production and exploitation of Alaskan, and perhaps also California heavy oil resources.

Volumes of proprietary data and feasibility studies exist within major companies producing ANS oil, yet only a limited amount of data is available in the public domain. With limited access to data, no comprehensive evaluation could be undertaken, but the size of the resource warrants a comprehensive study with industry participation and limited disclosure. This may prompt less opposition to opening up adjacent areas for exploration by those who currently oppose drilling. The size of reserves and recovery estimates have been mostly speculative and widely divergent. A number of EOR technologies for production of AHO have been reported in the literature including gas, CO_2, in situ combustion and steam. Thermal production of heavy oil (hot water/steam) has been attempted, but the results of the field pilot have not been made public. Close spacing will be required. Constraints on producing heavy oil in Alaska indicate that even with significant economic incentives and a significant increase in oil prices, little of the heavy oil in Alaska will be produced. If the current production decline and lack of further investment continue due to lack of access to explore and develop light oil reservoirs and better prospects elsewhere in the world, it is very likely that there will not be sufficient infrastructure or light oil diluent (for blending with heavy oil to lower viscosity) available for the development, production, and transport of Alaska's heavy oil resource.

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