Alaska

Oil & Gas Report

December 2004

Alaska Department of Natural Resources
Division of Oil & Gas
550 W 7th Ave. Suite 800
Anchorage, Alaska 99501
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Front cover:
Looking west across the Staines River, Eastern North Slope.
Bruce Webb

STATE OF ALASKA
Governor Frank H. Murkowski

ALASKA DEPARTMENT OF NATURAL RESOURCES
Tom Irwin, Commissioner

DIVISION OF OIL AND GAS
Mark D. Myers, Director

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Forward

This report replaces the annual “Historical and Projected Oil and Gas Consumption” report that the Division of Oil and Gas published between 1979 and 1999. The Division issued a 2000 annual report for year-end 1999 data, but did not issue a report for year-end 2000 data. Historical production for annual years 2000 and 2001 were published in the March 2003, Tables & Graphs Edition available on our web site. The 2003 Report included data ending December 31, 2002 and this report includes data ending December 31, 2003. This 2004 Report contains the division’s most recent oil production forecasts by field, and reserve estimates.

2004 Oil and Gas Report

For the period ending December 31, 2003

Alaska Department of Natural Resources
Division of Oil and Gas

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Introduction

This report is divided into five sections. Section I (Introduction) summarizes historic oil and gas production volume on Alaska's North Slope and Cook Inlet and discusses some of the methods and assumptions used in this report. Section II examines the state's oil and gas leasing programs, and exploration licensing and incentive programs. Section III presents oil and gas units in Alaska. It describes the individual units on the North Slope and in Cook Inlet and their producing reservoirs, sometimes called Participating Areas. Section IV includes tables and charts depicting historic and forecast oil and gas production through 2022. Finally, Section V presents tables describing historical royalty oil and gas production, and royalty-in-kind sales contracts by volume and by customer for each unit, participating area, or field.

Oil and Gas Reserves

Polar Resolution
PTI

Reserves begin with estimates of original oil or gas in-place (OOIP). Only a fraction of the original oil or gas in any reservoir can be extracted depending on available technology and production economics. Recoverable reserves, what is economically and technically feasible to extract vary between 15% and 85% of OOIP depending on the reservoir depth, rock and fluid type, technology, and to a lesser extent, market price. Total estimated recoverable and remaining recoverable reserves are the focus of this report, specifically Section IV. Reserves can be calculated by many methods and there is often no consensus on which method is best to apply to each reservoir at any given point in time. Three state agencies are responsible for evaluating oil and gas reserves and production: the Alaska Oil and Gas Conservation Commission (AOGCC), the Department of Revenue, Tax Division (DOR), and the Department of Natural Resources, Division of Oil and Gas (DOG). Each agency calculates reserves using slightly different methods. AOGCC emphasizes geologic and engineering factors to estimate the total recoverable resource. DOR calculations emphasize oil and gas production economics and the impact of oil prices forecasted far into future. DOG reserves are calculated from the forecast of production from existing and planned developments that may reasonably be expected to occur in the near future. These agencies cooperate and coordinate the preparation of reserves estimates and production forecasts.

Ultimate recovery estimates from large oil fields typically increase through their development years, i.e. ultimate recoveries are often greater than early predictions. In the early 1980's estimated reserves for the Prudhoe Bay Unit Initial Participating Area (PBU IPA) were between seven and nine billion barrels. By January 1986, ultimate recovery at the PBU IPA was projected to be 10.2 billion barrels; 4.4 billion produced and 5.8 billion remaining. By December 2002, estimated recovery increased to 13 billion barrels: 10.8 billion produced and 2.2 billion remaining reserves. By year-end 2003, we estimated the Prudhoe Bay field contains more than 2.8 billion recoverable barrels of oil. New investments, improved technologies, and careful costs management, all have helped to increase the portion of OOIP extracted from the Prudhoe Bay and Kuparuk fields. Further improvements in technology may increase future reserve estimates. Other factors affecting ultimate recovery are energy prices, the cost of new investment and ongoing operations, the impact of fiscal incentives, and competing development opportunities available to the state's oil and gas operators in other parts of the world.

North Slope oil reserve estimates developed by DOG are illustrated in detail in the oil forecast tables found in Section IV. As indicated above, remaining reserves in any particular North Slope production unit are defined in terms of cumulative production predicted for the next 18 years. Many of these units will

likely produce well beyond the forecast period that ends in 2022. This additional production will increase the ultimate recovery estimated in this report. Oil and gas reserve estimates for Cook Inlet fields also are based on cumulative forecast production. Reserves of undeveloped North Slope and Cook Inlet oil and gas fields are included in the forecast and, while speculative, they are based in part on the latest reports available from the producers as well as on DOG in-house interpretation.

The State of Alaska's royalty reserves are calculated by finding the product of each field's reserves with the state's royalty ownership interest in the field. On average, the state retains a 1/8th royalty interest in most of the producing oil and gas fields in Alaska. There are also third-party royalty owners in the Colville River and North Star Units on the North Slope, and Beluga River, Cannery Loop, Kenai, Sterling, Ninilchik, Nicolai Creek, Deep Creek, and West Forelands fields in the Cook Inlet. These units and fields include federal and private Native Corporation acreage. Also, the state derives royalty from numerous non-unitized oil and gas leases. The state has no royalty interest in the reserves in the East Barrow, South Barrow and Walakpa fields on the North Slope nor does the state have any royalty interest in the Swanson River, Beaver Creek, Lone Creek, Moquawkie or Birch Hill fields in the Cook Inlet.

Pump Station 4
G. Mull

Oil Production Forecast

North Slope production of oil, condensate, and natural gas liquids (NGLs), which peaked at 2.0 million barrels per day in 1988, declined to 1.0 million barrels per day in 2002 where it remains steady. By the end of the forecast period in 2022, ANS production will have droped to 513,000 barrels per day. Cook Inlet oil production peaked at 230,000 barrels per day in 1970, declined to 31,000 barrels per day in 2002 and 27,500 in 2003. Oil production in Cook Inlet is expected to continue to 2016. The projection includes oil production forecast from Swanson River and Beaver Creek even though the State gets no direct royalty share of that production. Details can be found in Section IV.

Oil Production History

First commercial production from an Alaska oil field began at Swanson River, Cook Inlet in 1959. Five other Cook Inlet fields began production between 1965 and 1972. Most recently, West McArthur River began production in 1993 and Redoubt in 2002. All Cook Inlet oil is currently shipped to the Tesoro refinery at Nikiski on the Kenai Peninsula. Oil from fields on the west side of Cook Inlet is transported by pipeline to the Drift River terminal, then transported to Nikiski. Oil from the eastside fields is shipped by pipeline directly to the refinery. By year-end 2003, the Cook Inlet has produced almost 1.3 billion barrels of oil, including 10 million barrels of NGLs.

Trans-Alaska Oil Pipeline
K. Banks

Oil production on the North Slope began in 1969 at Prudhoe Bay. Production was initially restricted to small quantities used to fuel field operations until the Trans Alaska Pipeline System (TAPS) was completed in July 1977. The operators injected surplus crude and residual oil back into the Prudhoe Bay reservoir. Similarly, oil production at the Endicott Field in the Duck Island Unit was re-injected into the reservoir until a pipeline linking Duck Island to TAPS was completed. From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time the proportion of both produced gas and water to oil increased. Eventually, oil production was constrained by the rate at which the separating plants could process gas and water. To alleviate this constraint the gas and water handling facilities were expanded in 1986, 1991, and 1993-94.

The 1999 miscible injectant "MIX" project also adds to the field's gas handling capacity.

The North Slope has produced 14.4 billion barrels of oil and natural gas liquids (NGLs) by the end of 2003; nearly all from the large Prudhoe Bay and Kuparuk fields. NGLs produced on the North Slope are blended with oil and shipped down TAPS or used to make miscible injectant (MI) for enhanced oil recovery projects. Since 1996, NGLs have been shipped from Prudhoe Bay to the Kuparuk River Unit via the Oliktok pipeline for MI in the Large-Scale Enhance Oil Recovery (LSEOR) project at Kuparuk. Today, incremental oil production from new fields brought on line since 1995 account for about 27 percent of total yearly Alaska North Slope production.

Gas Production History

Kenai Fertilizer Plant
D. Colley

Cook Inlet gas production began in 1959 as a by-product of Swanson River oil development. As more oil and gas fields were discovered nearby markets for the gas were developed in Anchorage and Kenai to supply space heat and electricity generation. In 1968 Unocal started up the ammonia-urea plant at Nikiski to take advantage of the abundance of cheap stranded natural gas. This plant was acquired in 2000 by Agrium, Inc., of Calgary, Alberta. In 1969, Phillips and Marathon began operating the liquid natural gas (LNG) plant, also located at Nikiski. In recent years, LNG exports to Japan accounted for about 1/3 of total Cook Inlet gas production. Industrial use of Cook Inlet gas has remained fairly constant since 1983; production has increased in step with the growing residential and commercial demand for space heating and electric power generation. Cook Inlet natural gas production has remained relatively stable at an average of 213 Bcf per year from 1997 to 2001.

North Slope gas production began near Barrow in the mid-1940s. This gas initially was used to fuel a nearby military base. Gas service was extended to the village after World War II. The East Barrow and Walakpa fields were developed in 1980 to provide gas to Barrow. Gross gas production on the North Slope in 2000 was 3.2 trillion cubic feet (8.7 billion cubic feet (bcf)) per day but 93 percent of this volume was injected into oil producing reservoirs. The remaining net gas production, equal to 297 Bcf in 2003, is consumed locally on the North Slope to fuel oil field equipment, operations, and pipelines (including the first four TAPS pump stations). North Slope industrial yearly gas consumption is approximately equal to annual gas produced in Cook Inlet.

The history of Swanson River gas production differs from other Cook Inlet fields. Swanson River injected gas imported from other fields to enhance oil production. In 1992 the operator began to "blow-down" the reservoir. In recent years, the Swanson River field has become a major net gas producer in Cook Inlet but as production rates decline it may soon provide gas storage services.

History

Pre-1950's Activity

Alaska's oil has long been the subject of interest and speculation. Historically, oil seeps were observed by Inupiat Eskimos, and according to archaeological evidence, oil shale was used for fuel by the indigenous peoples of the Arctic. As early as 1853, during the Russian period, oil was reported on the west side of Cook Inlet in the vicinity of the Iniskin Peninsula and in 1882, a Russian named Paveloff took the first samples of oil. Early traders on the North Slope also reported seeps along the coast. Early explorers and prospectors staked claims to oil along Cook Inlet in 1892 and 1896. In 1896, oil claims were staked at Katalla approximately 50 miles southeast of Cordova. Oil was discovered there in 1902. An on-site refinery near Controller Bay produced a total of 154,000 barrels over the thirty years it was in operation. The refinery burned down in 1933 and was not replaced. In about 1903, Austin Lathrop drilled three wells in the Cold Bay area and entrepreneurs drilled several wells near Chignik and other coastal areas of Alaska in search of oil. In 1910, all oil lands in Alaska except Katalla were withdrawn from entry by the federal government.. Since oil had been discovered at Katalla in commercial quantities, title was considered valid. Because of the land withdrawals, no oil drilling activity took place in Alaska for the next decade with the exception of Katalla. Drilling resumed after the Mineral Leasing Act of 1920 provided for two-year prospecting permits.

Puale Bay, AK Peninsula
T. Ryherd

On the North Slope, the first geologic and topographic studies date back to 1901 and the first formal descriptions were recorded by the U.S. Geological Survey in 1919. By 1921, prospecting permits were filed, and in 1923 President Harding established by executive order the Naval Petroleum Reserve No. 4 (NPR-4), now known as the National Petroleum Reserve-Alaska (NPR-A). The Geological Survey conducted reconnaissance mapping from 1923 through 1926 and published the results in 1930.

The first exploration phase of NPR-4 started in 1943 and ended in 1953. Between 1923 and 1953, the United States Navy drilled 37 test wells and found three oil accumulations and six gas accumulations within the reserve. Only two of these discoveries were considered sizable, namely Umiat, with an estimated 50 million barrels of recoverable oil, and Gubik, with an estimated 600 billion cubic feet of recoverable gas. Gas from another of the discoveries during that period, the small South Barrow field, is being produced today for local consumption at Barrow.

Puale Bay, AK Peninsula
T. Ryherd

Statehood - 1959

At the time of statehood, both Congress and Alaskans recognized the importance of the state's natural resources, specifically, oil and gas. In the late 1950's, Congress was debating the Alaska Statehood Act. A major concern expressed was how the potential new state, which was one of the poorest in the country, could support itself since it did not have an economic base sufficient to support the new state. As a result, the Alaska Statehood Act allowed the State of Alaska to select 104 million acres of land from the federal public domain. The Act also granted to Alaska the right to all minerals underlying these selections and specifically required the state to retain this mineral interest when conveying interests in the surface estate. The mineral estate was seen as so important to Alaska's financial survival that the Statehood Act provided that if Alaska disposed of its mineral estate contrary to the Act, it would forfeit that mineral estate to the federal government.

The importance of natural resources to the state of Alaska is addressed in Article VIII of the Alaska Constitution which became operative with the formal proclamation of statehood, January 3, 1959. Art. VIII, sec. 1 states that *"[i]t is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest."* The Alaska legislature realized the importance of oil and gas in Alaska's future. The Alaska Land Act of 1959 included a section specifically addressing the leasing and administration of the state's oil and gas resources It also recognized that other natural resources like coal and geothermal energy would play a major role in Alaska's future.

Cook Inlet

Modern day exploration in Cook Inlet began in 1955 when Richfield Oil Corporation began exploration on the Kenai Peninsula in the Swanson River area. Oil was discovered on July 23, 1957, at a depth of 11,000 feet and the discovery well flowed at a rate of about 900 barrels a day. This discovery began an oil rush in Southcentral Alaska.

Shortly after the Swanson River discovery, Standard Oil Company of California and Richfield formed a joint venture to explore for oil. Additional wells were drilled in the Swanson River area, and more leases were taken on both sides of Cook Inlet. Several other oil companies moved in to participate in leasing and drilling activities on the Kenai Peninsula. By 1959, 187,000 barrels of crude oil were produced annually. The state's first competitive sale was held December 10, 1959 bringing the state over $4 million in bonus bids.

Cook Inlet Platform
D. Colley

Following further development of the Swanson River and Soldotna Creek Units, annual production rose to 600,000 barrels by 1960. In 1962, Pan American Petroleum Corporation discovered the first offshore oil in Cook Inlet. This led to extensive exploration throughout the Cook Inlet region in the 1960's and 1970's. Chevron opened a refinery in 1963, and in 1969, the Tesoro refinery began operating. Cook Inlet production peaked at 83 million barrels per year in 1970 and had declined to 11 million barrels per year by 1999. Most of the larger fields were found by the mid-1960's.

The first major gas discovery occurred in October 1959 by Union Oil Company of California and Ohio Oil Company in the Kenai gas field. Gas production began the following year and continues today. Several additional large gas discoveries quickly followed and the Phillips/Marathon LNG project stared operating in 1969. The Unocal fertilizer plant began operation in 1968 and is now owned and operated by Agrium U.S., Inc. By 1984, net annual natural gas production reached 217 bcf per year, and peaked at 223 bcf in 1996.

The North Slope

The U.S. Department of the Interior, Bureau of Land Management opened North Slope lands for competitive bidding in 1958 when 16 thousand acres were offered in the area of the Gubik gas field. That same year, BLM opened four million acres in an area south and southeast of NPR-A (then named NPR-4) for simultaneous filing and subsequent drawing. From 1962-1964, industry exploration programs expanded rapidly. During this period, Sinclair and British Petroleum drilled a total of seven unsuccessful wildcat wells in the arctic foothills in search of oil.

Snow Geese
S. Schmitz

In 1964, in conjunction with the Statehood Act, the State of Alaska selected some 80 townships across the northern tier of lands between the Colville and Canning Rivers and received tentative approvals on 1.6 million acres from the federal government in October of the same year. In December 1964, the state held the first North Slope Competitive Sale. Lease Sale 13 covered 625,000 acres in the area east of the Colville River Delta. In July 1965, the state held Lease Sale 14 which included the onshore area in the vicinity of Prudhoe Bay. In Lease Sale 18, held January 1967, the offshore Prudhoe Bay tracts were offered and leased.

After drilling several dry holes in the area immediately surrounding the Prudhoe Bay structure, a rig was moved to the Prudhoe Bay State No. 1 location near the mouth of the Sagavanirktok River in early 1967. This proved successful, and in early 1968, Atlantic Richfield (ARCO) announced the discovery of what was to become the first commercial North Slope oil field at Prudhoe Bay. In 1969, Atlantic Richfield and British Petroleum agreed to jointly operate Prudhoe Bay. Prudhoe Bay Field did not begin production until 1977 after the construction of the 800-mile Trans-Alaska Pipeline.

Following the Prudhoe Bay discovery, exploration activity on the North Slope increased dramatically. Thirty-three exploration wells were completed in 1969 as industry prepared for Lease Sale 23 in September of that year. The state offered more than 450,000 acres along the Arctic coast between the Canning and Colville rivers and earned over $900 million in bonus bids on 164 tracts. The next North Slope sale was not held until 1979, however, during this time, over 100 exploratory wells were drilled on the North Slope with 19 of those wells discovering oil or gas.


Brooks Range Foothills, ANWR
B. Webb

Since 1959 the State has held 101 competitive lease sales in which it has offered millions of acres throughout Alaska. By year-end 2002, 27 exploratory wells had been drilled in the federal waters of the Beaufort Sea resulting in four discoveries. These discoveries are Kuvlum, Hammerhead, Sandpiper, and Tern Island/Liberty. Since 1999, several sales weres held in NPR-A and several exploration wells drilled.

Exploration wells drilled on North Slope state leases since the Prudhoe Bay discovery have resulted in dozens of discoveries, many of which were found in the vicinity of Prudhoe Bay. Most of the post-Prudhoe Bay discoveries are currently producing oil because of the existence of Prudhoe Bay infrastructure and their relatively close location to the Trans-Alaska Pipeline. Five of these, Lisburne, Kuparuk, Milne Point, Endicott, and Point McIntyre are major fields. Fields recently brought into production are Alpine, Northstar, Tarn, Meltwater, West Sak and Northstar. Although initial production on the North Slope was from onshore areas, six fields produce at least some of their reserves from offshore areas including Endicott, Lisburne, Prudhoe Bay, Point McIntyre, Milne Point, Niakuk, and Northstar.


Tree Row
S. Schmitz


Alaska Highway
B. Havelock

Outlook

Oil Production and Natural Gas Development

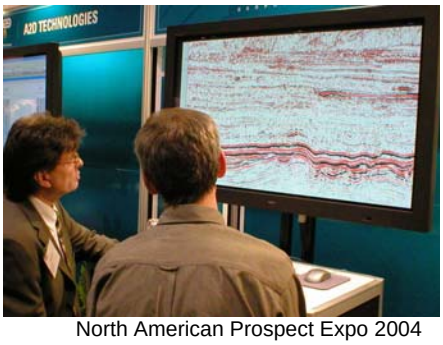
While production from the largest of North Slope fields, Prudhoe and Kuparuk is in decline, smaller and more numerous satellite oil and gas reservoirs are being developed and produced. New companies have entered the Alaska crude oil and gas upstream sector in recent years. Interest continues to grow, especially among independent exploration and production companies and in areas beyond the mature oil provinces of the North Slope and Cook Inlet. The long-term picture for oil production is one of gradual decline, supplemented with smaller field-size oil development and with gas field development in or near existing infrastructure.

While drilling activity shows slight increases in recent years and the total number of feet drilled per year has been relatively steady since the mid-eighties, total oil production has steadily declined since it peaked at two million barrels per day in 1988. Gross oil and natural gas liquid (NGL) production from state lands continues to decline. The lion's share of Alaska oil production comes from the North Slope, from the Nation's largest oilfields of Prudhoe Bay and Kuparuk. The current production rate from the North Slope is slightly under one million barrels per day. We expect that rate to hold steady at or near one million barrels per day for at least the next eight years.

Sustained drilling activity is a result of new discoveries, satellite field development in or near Prudhoe/Kuparuk infrastructure, in-field drilling, re-working of wells, side-tracking of wells to reach "behind the pipe" oil, and advances in drilling and completion efficiency (new fluids, technology, tools, materials) in the main Prudhoe and Kuparuk pools. In Cook Inlet, stepped-up gas exploration drilling is driven by decline in production from existing fields.

Incentives

Since 2001, we have seen a new surge in exploration interest with smaller, aggressive companies looking for gas, not just oil, in under-explored areas of Alaska, like the North Slope Foothills, other Interior Alaskan basins and the Alaska Peninsula region. This exploration is driven by increasing demand for energy here in Alaska, as well as across the North American continent coupled with the availability of land and prospects in Alaska. Alaska oil and gas will continue to play a fundamental if not critical role in meeting the Nation's energy needs.



North American Prospect Expo 2004
B. Havelock

While statistics show the total number of separate reservoirs in production increasing they are smaller and may not stem the overall decline of North Slope production later this decade. In an attempt to avert the decline in oil production, the Division has created new programs to attract explorers to areas of Alaska.

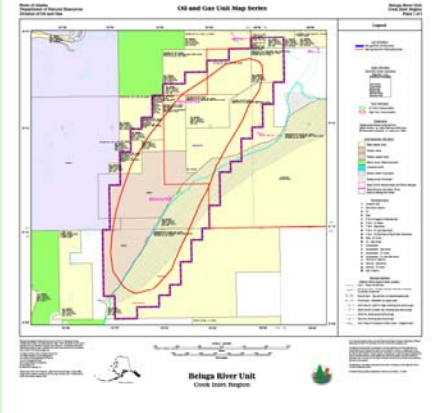
ADNR holds four regularly scheduled oil and gas lease sales per year. The Division of Oil and Gas and the Division of Geological and Geophysical Survey are working on obtaining geologic and geophysical data as well as conducting its own field work in new areas. DGGS and DO&G geologists completed field work that will help companies in evaluating hydrocarbon potential for the proposed Alaska Peninsula Oil and Gas Lease Sale tentatively scheduled for fall 2005. In addition to competitive areawide leasing, ADNR has instituted an exploration licensing program to encourage exploration in oil and gas basins outside of Cook Inlet and the North Slope. Four exploration licenses have already been issued – in the Nenana and Copper River basins, and two licenses in the Susitna basin. Recently, DO&G received

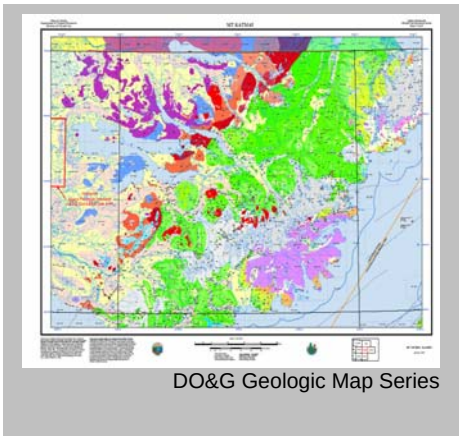
exploration license proposals for the northern portion of the Bristol Bay basin and Healy area. A short-lived shallow natural gas leasing program allowed DO&G to issue non-competitive leases to explore for and develop natural gas reservoirs, including coalbed methane, located within 3,000 feet of the surface. For additional details, see Section II.

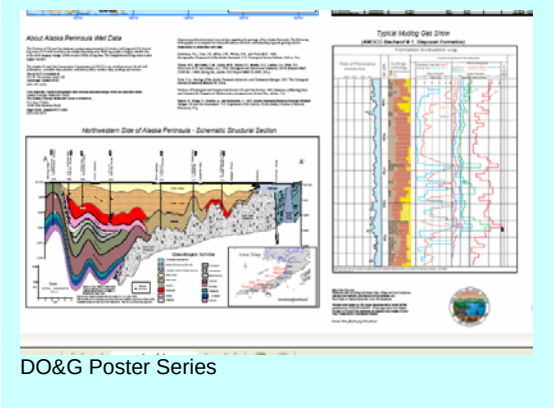
ADNR remains committed to environmentally safe exploration and development of its oil and gas resources. The Division of Mining Land and Water and the University of Alaska completed a study on tundra travel which resulted in a longer exploration season on the North Slope. The Division of Oil and Gas has worked closely with new Cook Inlet and North Slope explorers including Pelican, Alliance, Pioneer Oil & Gas, Pioneer Natural Resources, AVCG, Kerr-McGee, and Armstrong to facilitate their exploration activities, and the Department has made a special effort to disseminate information to new companies seeking to invest in Alaska. Steps have been taken to streamline permitting, including revising the Alaska Coastal Management Program and creating a large project permit office in the ADNR. ADNR has been studying a natural gas pipeline to the Lower 48 states in an effort that includes economic modeling of gas sales and pipeline options; negotiations with North Slope gas producers and companies like TransCanada; and accelerated processing of pipeline Rights of Way applications. ADNR is also committed to ensuring that companies have access to existing facilities and pipelines, and that pipeline tariffs are just and reasonable.


Alaska Natural Gas Pipeline Corridor

The Division has several exploration incentives available, including drilling and seismic credits, and royalty reduction. For additional information on programs and incentives, see Section II and contact Pat Galvin, Leasing Petroleum Land Manager, 907-269-8775 or email: Patrick_Galvin@dnr.state.ak.us


DO&G Unit Map Series


DO&G Geologic Map Series


DO&G Poster Series

Section Two

Leasing Licensing & Incentives

Leasing

Areawide Leasing

Oil and gas lease sales are the initial step in a process that generates nearly 80 percent of the State's General Fund Revenue. Although the primary purpose of leasing State lands is to provide for oil and gas development and the subsequent economic benefits, the program in itself has been a significant revenue source. Through lease sale bonus bids alone, the State has received over $2 billion in revenue.

Since 1959 the State has held 101 competitive lease sales in which it has offered millions of acres throughout Alaska. Several leasing methods, authorized under the AS 38.05, were used to encourage responsible oil and gas exploration and development and maximize State revenue. These methods include combinations of fixed and variable bonus bids, royalty shares and net profit shares. The fixed lease terms generally involve an obligation to remit royalty payments in the form of a $12^{1/2}$ or $16^{2/3}$ percent share of gross production paid in-kind or in-value. Occasionally, the State has imposed a fixed royalty rate of 20 percent. The minimum royalty obligation is $12^{1/2}$ percent. The State has also used sliding-scale royalty terms in its leases based on production or oil price or gross revenue.

Areawide Leasing
ADNR, DO&G

The most common bid variable used by the State is the cash bonus. The State may require minimum bids of $5 to $10 per acre (and sometimes higher). The State may also use the royalty rate or the net profit share as the bidding variable, though this has happened only rarely (Sale 30, the joint federal-state Beaufort Sea sale held in 1979 was one of these occasions).

The Division annually issues a new *Five-Year Oil and Gas Leasing Program* that sets out the sale schedule for the succeeding five years. All proposed lease sales are Areawide sales held each year. An Areawide sale is one in which all available State acreage within a geographic region is included. Traditionally, the four geographic regions have been the North Slope, North Slope Foothills, Beaufort Sea, and Cook Inlet. The first such sale was the North Slope Areawide held in June 1998. Since then, Areawide sales have been held in the other three regions. In addition, the State has added Areawide sales on the Alaska Peninsula, located in Southwest Alaska, beginning in 2005. Areas outside these regions are available for exploration through other oil and gas programs.

Sale Areas
A total of 24 lease sales are proposed over the next five years; five in each region of northern Alaska and in Cook Inlet, and four on the Alaska Peninsula beginning in 2005.

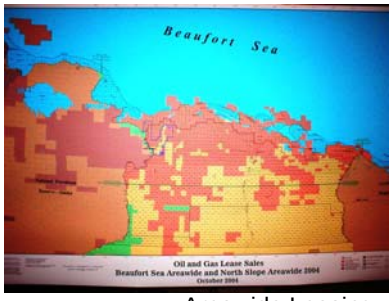
STATE OF ALASKA
FIVE-YEAR OIL AND GAS LEASING PROGRAM

2004 through 2008

Sale	Annually Held In
North Slope Foothills Areawide	May
Cook Inlet Areawide	May
North Slope Areawide	October
Beaufort Sea Areawide	October
Alaska Peninsula	October (beginning in 2005)

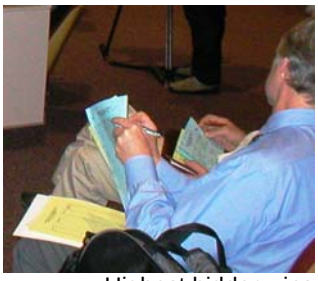
Leasing

If the decision is to proceed with a sale, a Sale Announcement, including the sale terms, bidding method, tract map, and mitigation measures will be issued 90 days prior to that sale. If a best interest finding or a supplement to a previous finding is required, it will be released at the same time as the Sale Announcement.



Areawide Leasing


Competitive sealed bid


Highest bidder wins

Shallow Gas Leasing

Exploration Licensing
C. Beaty

Alaska's Shallow Gas Leasing Program underwent much change in 2004. This program originally allowed the Division of Oil and Gas to issue non-competitive leases to explore for and develop natural gas from fields if part of the field was within 3,000 feet of the surface. In 2004, the legislature repealed the program and replaced it with provisions added to the areawide leasing and exploration licensing programs that allow for gas-only leases and licenses. The new program includes lease and license terms that encourage competitive leasing for development of unconventional gas resources.

The 2004 legislation addressed a number of concerns raised by the public associated with the shallow gas leasing program and the related topic of coalbed methane development. In particular, the legislation ensures that all future oil and gas leasing and licensing decisions will be based upon a finding that issuance of the lease or license is in the best interest of the state. Also, the legislation provides for protection of drinking water sources, requires noise mitigation and setback standards, and provides additional surface owner protections. Additionally, after a comprehensive public process, ADNR adopted enforceable standards for CBM development in the Mat-Su Borough to further address public concerns.

At present, there are 4 shallow natural gas leases active in Northwest Alaska in the vicinity of Red Dog Mine and 8 shallow natural gas leases active in South-central Alaska in the vicinity of Homer. All other shallow natural gas leases (in the Mat-Su and Delta areas) have either expired or are in the process of being relinquished. All shallow natural gas lease applications (in the Mat-Su, Holitna and Healy areas) pending at the time of passage of the 2004 legislation have either been closed or converted to exploration licenses.

SUMMARY OF STATE COMPETITIVE LEASE SALES

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
12/10/1959	1	Cook Inlet	88,055	77,191	87.66%	$52.08	37	31	$4,020,342	Bonus; No Min	12.5% Royalty
7/13/1960	2	Cook Inlet	17,568	16,506	93.96%	$24.70	27	26	$407,655	Bonus; No Min	12.5% Royalty
12/7/1960	3	Mixed	73,048	22,867	31.30%	$1.54	26	9	$35,325	Bonus; No Min	12.5% Royalty
1/25/1961	4	Cook Inlet	400	400	100.00%	$679.04	3	3	$271,614	Bonus; No Min	12.5% Royalty
5/23/1961	5	Mixed	97,876	95,980	98.06%	$74.71	102	99	$7,170,465	Bonus; No Min	12.5% Royalty
8/4/1961	6	Gulf Ak	13,257	13,257	100.00%	$8.35	6	6	$110,672	Bonus; No Min	12.5% Royalty
12/19/1961	7	Mixed	255,708	187,118	73.18%	$79.43	68	53	$14,863,049	Bonus; No Min	12.5% Royalty
4/24/1962	8	Cook Inlet	1,062	1,062	100.00%	$4.80	8	8	$5,097	Bonus; No Min	12.5% Royalty
7/11/1962	9	Mixed	315,669	264,437	83.77%	$59.42	89	76	$15,714,113	Bonus; No Min	12.5% Royalty
5/8/1963	10	Cook Inlet	167,583	141,491	84.43%	$29.23	200	158	$4,136,225	Bonus; No Min	12.5% Royalty
12/11/1963	12	Cook Inlet	346,782	247,089	71.25%	$12.31	308	207	$3,042,681	Bonus; No Min	12.5% Royalty
12/9/1964	13	Mixed	1,194,373	721,224	60.39%	$7.68	610	341	$5,537,100	Bonus; No Min	12.5% Royalty
7/14/1965	14	North Slope	754,033	403,000	53.45%	$15.25	297	159	$6,145,473	Bonus; $1/acre Min	12.5% Royalty
9/28/1965	15	Cook Inlet	403,042	301,751	74.87%	$15.49	293	216	$4,674,344	Bonus; $1/acre Min	12.5% Royalty
7/19/1966	16	Mixed	184,410	133,987	72.66%	$52.55	205	153	$7,040,880	Bonus; $1/acre Min	12.5% Royalty
11/22/1966	17	Cook Inlet	19,230	18,590	96.67%	$7.33	36	35	$136,280	Bonus; $1/acre Min	12.5% Royalty
1/24/1967	18	Mixed	47,729	43,657	91.47%	$33.90	23	20	$1,479,906	Bonus; $1/acre Min	12.5% Royalty
3/28/1967	19	Kachemak Bay	2,560	RULED INVALID 12/9/74							
7/25/1967	20	Cook Inlet	311,250	256,447	82.39%	$73.14	295	220	$18,757,341	Bonus; $1/acre Min	12.5% Royalty
3/26/1968	21	Ak Pen	346,623	164,961	47.59%	$18.24	308	147	$3,009,224	Bonus; $1/acre Min	12.5% Royalty
10/29/1968	22	Cook Inlet	111,199	60,272	54.20%	$17.29	230	125	$1,042,220	Bonus; No Min	12.5% Royalty
9/10/1969	23	North Slope	450,858	412,548	91.50%	$2,181.66	179	164	$900,041,605	Bonus; No Min	12.5% Royalty
5/12/1971	24	Cook Inlet	196,635	92,618	47.10%	$4.92	244	106	$455,641	Bonus; No Min	12.5% Royalty
9/26/1972	25	Cook Inlet	325,401	178,245	54.78%	$7.43	259	152	$1,324,673	Bonus; No Min	12.5% Royalty
12/11/1972	26	Cook Inlet	399,921	177,973	44.50%	$8.75	218	105	$1,557,849	Bonus; No Min	12.5% Royalty
5/9/1973	27	Cook Inlet	308,401	113,892	36.93%	$9.92	210	96	$1,130,325	Bonus; No Min	12.5% Royalty
12/13/1973	28	Cook Inlet	166,648	97,804	58.69%	$253.77	98	62	$24,819,190	Bonus; No Min	16.67% Royalty
10/23/1974	29	Cook Inlet	278,269	127,120	45.68%	$8.19	164	82	$1,040,910	Bonus; No Min	16.67% Royalty
7/24/1979	29B	Copper Riv	34,678	34,678	100.00%	$4.56	20	20	$158,042	Bonus; No Min	20% Royalty
12/12/1979	30	Beaufort Sea	341,140	296,308	86.86%	$1,914.87	71	62	$567,391,497	Net Profit Share (NPS)	20% Royalty; $850 & $1750/acre
9/16/1980	31	North Slope	196,268	196,268	100.00%	$63.12	78	78	$12,387,470	Bonus; No Min	20% Royalty; 30% NPS
5/13/1981	33	Cook Inlet	815,000	429,978	52.76%	$10.00	202	103	$4,299,782	Royalty; 20% Min	$10/acre Bonus
8/25/1981	32	Cook Inlet	202,837	152,428	75.15%	$10.00	78	59	$1,524,282	Royalty; 20% Min	$10/acre Bonus
2/2/1982	35	Cook Inlet	601,172	131,191	21.82%	$10.00	149	31	$1,311,907	Royalty; 12.5% Min	$10/acre Bonus
5/26/1982	*36	Beaufort Sea	56,862	56,862	100.00%	$573.02	13	13	$32,583,452	Bonus; No Min	12.5% Royalty & 40% NPS
8/24/1982	*37	Copper River	852,603	168,849	19.80%	$3.33	217	33	$562,944	Bonus; No Min	12.5% Royalty & 30% NPS
8/24/1982	37A	Cook Inlet	1,875	1,875	100.00%	$52.00	1	1	$97,479	Bonus; No Min	43% Royalty
9/28/1982	*34	North Slope	1,231,517	571,954	46.44%	$46.70	261	119	$26,713,018	Bonus; No Min	Royalty:16.67%-40%NPS; 12.5%-30%NPS
5/17/1983	*39	Beaufort Sea	211,988	211,988	100.00%	$99.05	42	42	$20,998,101	Bonus; $10/acre Min	12.5% Royalty & 30% or 40% NPS
9/28/1983	40	Cook Inlet	1,044,745	443,355	42.44%	$7.17	284	140	$3,177,178	Bonus; $1/acre Min	12.5% Royalty
5/22/1984	43	Beaufort Sea	298,074	281,784	94.53%	$114.32	69	66	$32,214,794	Bonus; $10/acre Min	16.67% Royalty
5/22/1984	*43A	North Slope	76,079	76,079	100.00%	$125.44	15	15	$1,612,583	Bonus; $10/acre Min	12.5% Royalty & 30% NPS
9/18/1984	41	Bristol Bay	1,437,930	278,939	19.40%	$3.03	308	63	$843,965	Bonus; No Min	12.5% Royalty
2/26/1985	46A	Cook Inlet	248,585	190,042	76.45%	$13.28	65	50	$2,523,334	Bonus; $1/acre Min	12.5% & 16.67% Royalty
9/24/1985	45A	North Slope	606,385	164,885	27.19%	$28.25	113	32	$4,657,478	Bonus; $5/acre Min	16.67% Royalty
9/24/1985	47	North Slope	192,569	182,560	94.80%	$63.79	50	48	$11,645,003	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48	North Slope	526,101	266,736	50.70%	$9.16	104	54	$2,444,342	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48A	Beaufort Sea	42,053	42,053	100.00%	$12.13	11	11	$510,255	Bonus; $5/acre Min	12.5% Royalty
6/24/1986	49	Cook Inlet	1,189,100	394,881	33.21%	$2.40	260	98	$947,171	Bonus; $1/acre Min	12.5% & 16.67% Royalty
1/27/1987	51	North Slope	592,142	100,632	16.99%	$2.88	119	26	$289,625	Bonus; $2/acre Min	12.5% Royalty
6/30/1987	50	Beaufort Sea	118,147	118,147	100.00%	$56.05	35	35	$6,621,723	Bonus; $5/acre Min	16.67% Royalty
1/26/1988	*54	North Slope	421,809	338,687	80.29%	$13.83	89	72	$4,683,388	Bonus; $5/acre Min	12.5% Royalty
9/28/1988	55	Beaufort Sea	201,707	96,632	47.91%	$152.13	56	25	$14,700,602	Bonus; $10&$25/ac Min	12.5% & 16.67% Royalty
9/28/1988	69A	North Slope	775,555	368,490	47.51%	$16.61	155	75	$6,119,135	Bonus; $5/acre Min	12.5% Royalty

SUMMARY OF STATE COMPETITIVE LEASE SALES

1/24/1989	52	Beaufort Sea	175,981	52,463	29.81%	$33.12	43	15	$1,737,513	Bonus; $10/acre Min	12.5% Royalty
1/24/1989	72A	North Slope	677	677	100.00%	$671.90	1	1	$454,977	Bonus; $10/acre Min	12.5% Royalty
1/29/1991	*67A	Cook Inlet	549,364	191,588	34.87%	$28.77	140	55	$5,511,338	Bonus; $5/acre Min	12.5% Royalty
1/29/1991	*70A	North Slope	532,153	420,568	79.03%	$65.88	135	109	$27,707,541	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	64	North Slope	754,542	34,143	4.52%	$7.10	141	6	$242,389	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	*65	Beaufort Sea	491,091	172,865	35.20%	$40.46	108	36	$6,993,949	Bonus; $5/acre Min	16.67% Royalty
9/24/1991	*74A	Cook Inlet	605,851	26,605	4.39%	$12.06	134	5	$320,853	Bonus; $5/acre Min	12.5% Royalty
1/22/1992	61	North Slope	991,087	260,550	26.29%	$9.32	181	46	$2,429,551	Bonus; $5/acre Min	12.5% Royalty
6/2/1992	68	Beaufort Sea	153,445	0	0.00%	$0.00	36	0	$0	Bonus; $10/acre Min	12.5% Royalty
12/8/1992	75	North Slope	217,205	124,832	57.47%	$78.11	90	55	$9,750,111	Bonus; $10/acre Min	State =12.5% & ASRC =16.67%
1/26/1993	76	Cook Inlet	393,025	141,504	36.00%	$461.25	86	36	$65,269,167	Bonus; $5/acre Min	12.5% Royalty
1/26/1993	67 A-W	Cook Inlet	282,577	129,810	45.94%	$18.75	69	33	$2,433,864	Bonus; $5/acre Min	12.5% Royalty
5/25/1993	77	North Slope	1,260,146	45,727	3.63%	$25.47	228	8	$1,164,555	Bonus; $5/acre Min	12.5% Royalty
5/25/1993	70 A-W	North Slope	37,655	28,055	74.51%	$48.41	11	8	$1,358,027	Bonus; $10/acre Min	12.5% Royalty
9/21/1993	57	North Slope	1,033,248	0	0.00%	$0.00	196	0	$0	Bonus; $5/acre Min	12.5% Royalty
9/21/1993	75A	North Slope	14,343	14,343	100.00%	$31.36	11	11	$449,847	Bonus; $10/acre Min	16.67% Royalty
10/30/1994	78	Cook Inlet	396,760	136,307	34.36%	$12.14	90	34	$1,654,137	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	67A-W2	Cook Inlet	152,768	13,804	9.04%	$7.29	36	3	$100,638	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	74W	Cook Inlet	66,703	17,015	25.51%	$31.76	16	4	$540,406	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	76W	Cook Inlet	251,614	14,220	5.65%	$5.61	50	4	$79,722	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	78W	Cook Inlet	260,453	36,478	14.01%	$7.06	56	11	$257,583	Bonus; $5/acre Min	12.5% Royalty
12/5/1995	80	North Slope	951,302	151,567	15.93%	$22.02	202	42	$3,337,485	Bonus; $10/acre Min	12.5% Royalty
10/1/1996	86A	North Slope	15,484	5,901	38.11%	$343.40	13	5	$2,026,247	Bonus; $100/acre Min	16.67%&16.67-33.33% SSR
12/18/1996	85A	Cook Inlet	1,061,555	173,503	16.33%	$17.92	234	44	$3,109,603	Bonus; $5/acre Min	12.5% Royalty
11/18/1997	86 **	Beaufort Sea	365,054	323,835	88.70%	$86.42	181	162	$27,985,125	Bonus, $10/acre Min	16.67% Royalty
2/24/1998	85A-W	Cook Inlet	757,878	98,011	12.90%	$8.46	157	24	$828,807	Bonus, $5/acre Min	12.5% Royalty
6/24/1998	87	North Slope	Areawide	518,689	N/A	$99.86	N/A	137	$51,794,173	Bonus, $5/acre Min	12.5% Royalty
2/24/1999	NS 1999	North Slope	Areawide	174,923	N/A	$14.85	N/A	40	$2,596,838	Bonus; $5/acre Min	12.5% Royalty
4/21/1999	CI 1999	Cook Inlet	Areawide	114,514	N/A	$10.75	N/A	41	$1,436,685	Bonus; $5/acre Min	12.5% Royalty
8/16/2000	CI 2000	Cook Inlet	Areawide	100,480	N/A	$9.15	N/A	27	$919,750	Bonus; $5/acre Min	12.5% Royalty
11/15/2000	BS 2000	Beaufort Sea	Areawide	25,840	N/A	$13.13	N/A	11	$338,922	Bonus; $10/acre Min	12.5% & 16.67% Royalty
11/15/2000	NS 2000	North Slope	Areawide	652,355	N/A	$15.41	N/A	145	$10,052,665	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/9/2001	CI 2001	Cook Inlet	Areawide	102,523	N/A	$9.05	N/A	29	$928,085	Bonus; $5/acre Min	12.5% Royalty
5/9/2001	NSF 2001	NS Foothills	Areawide	858,811	N/A	$11.41	N/A	170	$9,799,277	Bonus; $5/acre Min	12.5% Royalty
10/24/2001	BS 2001	Beaufort Sea	Areawide	36,331	N/A	$94.90	N/A	24	$3,447,734	Bonus; $10/acre Min	12.5% & 16.67% Royalty
10/24/2001	NS2001	North Slope	Areawide	434,938	N/A	$15.89	N/A	146	$6,911,572	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/1/2002	CI 2002	Cook Inlet	Areawide	64,923	N/A	$7.05	N/A	21	$421,841	Bonus; $5/acre Min	12.5% Royalty
5/1/2002	NSF 2002‡	NS Foothills	Areawide	213,374	N/A	$14.32	N/A	51	$2,889,532	Bonus; $5/acre Min	12.5% Royalty
10/24/2002	BS 2002	Beaufort Sea	Areawide	19,226	N/A	$26.34	N/A	15	$506,405	Bonus; $10&$100/ac Min	12.5%, 16.67% & 20% Royalty
10/24/2002	NS 2002	North Slope	Areawide	32,316	N/A	$17.94	N/A	12	$579,728	Bonus: $10/acre Min	12.5%,16.67%&16.67-33.33% SSR
5/7/2003	CI 2003	Cook Inlet	Areawide	73,869	N/A	$9.34	N/A	27	$689,949	Bonus; $5/acre Min	12.5% Royalty
5/7/2003	NSF 2003	NS Foothills	Areawide	5,760	N/A	$6.35	N/A	1	$36,576	Bonus; $5/acre Min	12.5% Royalty
10/29/2003	BS 2003	Beaufort Sea	Areawide	36,995	N/A	$33.96	N/A	20	$1,358,187	Bonus; $5 & $10/ac Min	12.5 % 16.67% Royalty
10/29/2003	NS 2003**	North Slope	Areawide	210,006	N/A	$17.08	N/A	75	$3,586,400	Bonus; $10/acre Min	12.5 % 16.67% Royalty
5/19/2004	CI 2004	Cook Inlet	Areawide	363,520	N/A	$7.23	N/A	72	$2,629,820	Bonus: $5/acre Min	12.5% Royalty
5/19/2004	NSF 2004	NS Foothills	Areawide	28,800	N/A	$5.37	N/A	5	$154,656	Bonus; $5/acre Min	12.5% Royalty
10/29/2004	BS 2004	Beaufort Sea	Areawide	125,440	N/A	$42.09	N/A	28	$5,280,384	Bonus; $10/acre Min	12.5% - 16.67% Royalty
10/29/2004	NS 2004	North Slope	Areawide	225,280	N/A	$41.94	N/A	61	$9,447,757	Bonus; $10/acre Min	12.5% - 16.67% Royalty
TOTAL: 101 Sales				**17,001,049**		**$121.79**		**6,145**	**$2,070,539,118**		

'*Economic Incentive Credits were offered for these sales.

** Sale 86A: State received $259,435; ASRC received $1,766,812.

‡ Sale NSF 2002 Bonus does not include 20% of Bonus bid ($1.25 million) retained by the state for relinquished tracts.

** NS 2003: State received $3,546,578; ASRC received $39,822.

Licensing

Exploration Licensing

Exploration Licenses are designed to stimulate exploration in Alaska's frontier basins, and complement the State's oil and gas leasing program. The North Slope and Cook Inlet, which are the main thrust of the State's competitive leasing program, remain off limits to Exploration Licensing.

There are, however, several large sedimentary basins within interior Alaska, some of which are virtually unexplored. The highly variable structural geology of these basins offers the potential for structural traps in overthrust belts and strike slip systems. Various types of clastic and carbonate stratigraphic traps may also be present. Exploration Licensing will allow companies to explore these frontier basins with minimal initial costs.

Mat-Su coring program
C. Ruff

An area selected for Exploration Licensing must be between 10,000 to 500,000 acres. A license will be awarded to the applicant who has committed the most dollars to an exploration program. The recipient of a license will be required to post a bond in the amount of the work commitment and pay a $1 per acre license fee. There are no additional charges during the term of the license, which can be up to 10 years.

During its term any portion of the licensed area may be converted to oil and gas leases. The term of the leases can then extend beyond the original term of the license. If converted, annual lease rentals are set at $3 per acre.

Susitna Basin
Aeromagnetic survey
K. Dirks

Licensing Process

The licensing process will be initiated in one of two ways: Each year during the month of April applicants may submit to the Commissioner of the Department of Natural Resources a proposal to conduct exploratory activity within an area they have specified. Or the commissioner, at anytime, can issue a notice requesting the submittal of proposals to explore an area designated by the commissioner. Once a request for proposals has been issued applicants will have 20 days to notify the commissioner of their intent to submit a proposal, and 60 days in which to submit.

Within 30 days of receiving any proposal the commissioner will either reject it in a written decision or give public notice of the intent to evaluate the proposal's acceptability. This notice will solicit public comments on the proposal(s) and request competing proposals. The commissioner may also modify any proposal and request a new one based on those modifications.

Submitted proposals must (1) describe the area proposed to be subject to licensing, (2) state the specific minimum work commitment expressed in dollars, (3) describe the amount and form of security to be posted based on the projected cost of the planned exploration work, (4) propose the term of the license (unless already established by the commissioner) and (5) verify that a prospective licensee meets minimum qualifications.

Licensing

Best Interest Finding

After considering all submitted proposals and public comment on those proposals the commissioner shall issue a written finding determining whether or not granting the Exploration License is in the State's best interests. The finding must describe the limitations, conditions, stipulations or changes from the initiating proposal or competing proposals that are required to make the issuance of the license conform to the best interests of the State. If only one proposal was submitted, the finding must also identify the prospective licensee.

If the finding concludes that an Exploration License should be awarded and there has only been a single applicant, that applicant will have 30 days after issuance of the finding to accept or reject the license award.

Alaska Peninsula seep
M. Myers

Bidding Process

If competing proposals are submitted and the commissioner determines that an Exploration License should be awarded, the commissioner will issue an invitation to submit a sealed bid. A bid deposit equal to 20 percent of the license fee must be submitted with the bid. The successful bidder will be the applicant who submits the highest bid in terms of exploration expenditures.

Once notified a successful bidder will have 10 days in which to accept or reject the license award. If the successful bidder fails to accept the award within the allotted time the bid deposit and the right to accept the award are forfeited. The next successive highest bidders will then have an opportunity to accept the award.

Relinquishment of Lands

If by the fourth anniversary of the Exploration License the licensee has completed less than 25 percent of the total work commitment the license will be terminated, with the remainder of the security forfeited to the State. If the licensee has completed less than 50 percent of the total work, then 25 percent of the licensed area will be relinquished, with an additional 10 percent relinquished each successive year until half of the original acreage has been relinquished.

License Applications

The State has issued four Exploration Licenses covering 1.66 million acres and currently has one pending in the northern portion of the Bristol Bay basin.

Licenses Issued:

Copper River

Licensee:	Forest Oil Corporation
Size:	318,756.35 Acres
Exploration Commitment:	$1,420,000
Term:	5 years
Effective Date:	October 1, 2000

Nenana Basin

Licensee:	Andex Resources
Size:	483,942 Acres
Exploration Commitment:	$2,525,000
Term:	7 years
Effective Date:	October 1, 2002

North Slope mosquitoes
S. Schmitz

Susitna Basin I

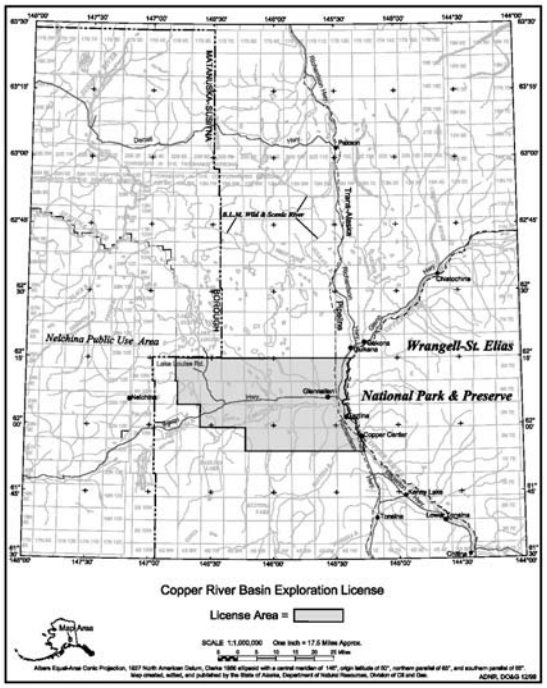
Licensee:	Forest Oil Corporation
Size:	386,204 Acres
Exploration Commitment:	$2,520,000
Term:	7 years
Effective Date:	November 1, 2003

Susitna Basin II

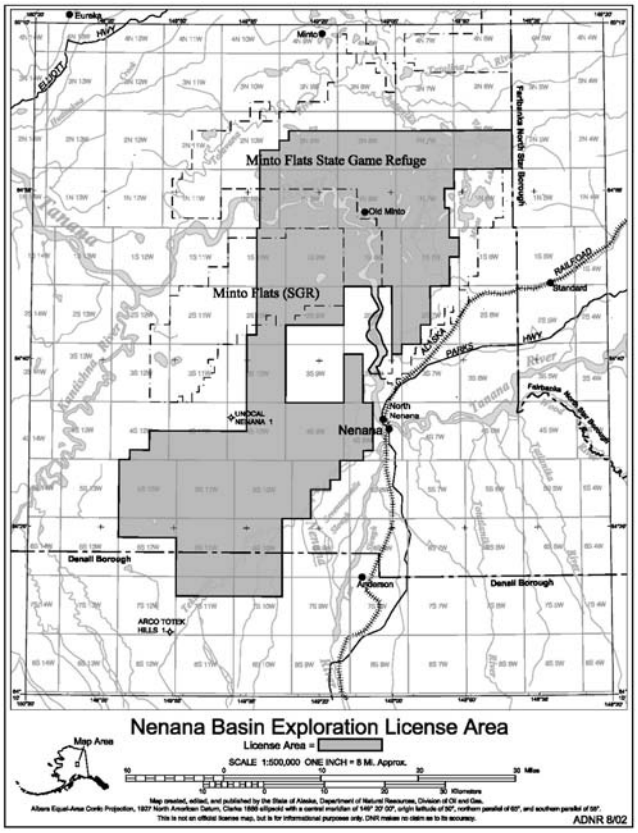
Licensee:	Forest Oil Corporation
Size:	471,474 Acres
Exploration Commitment:	$3,000,000
Term:	7 years
Effective Date:	November 1, 2003

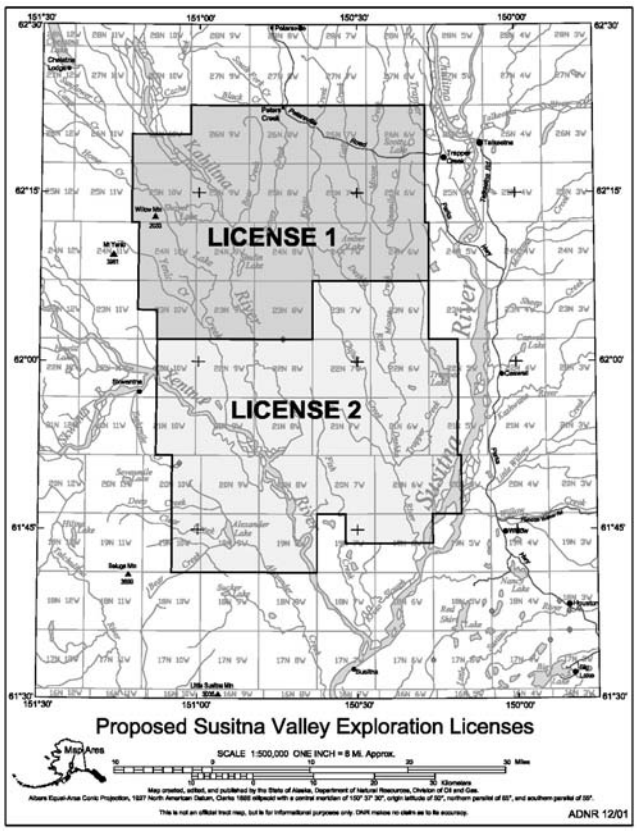
Bristol Bay (Proposed)

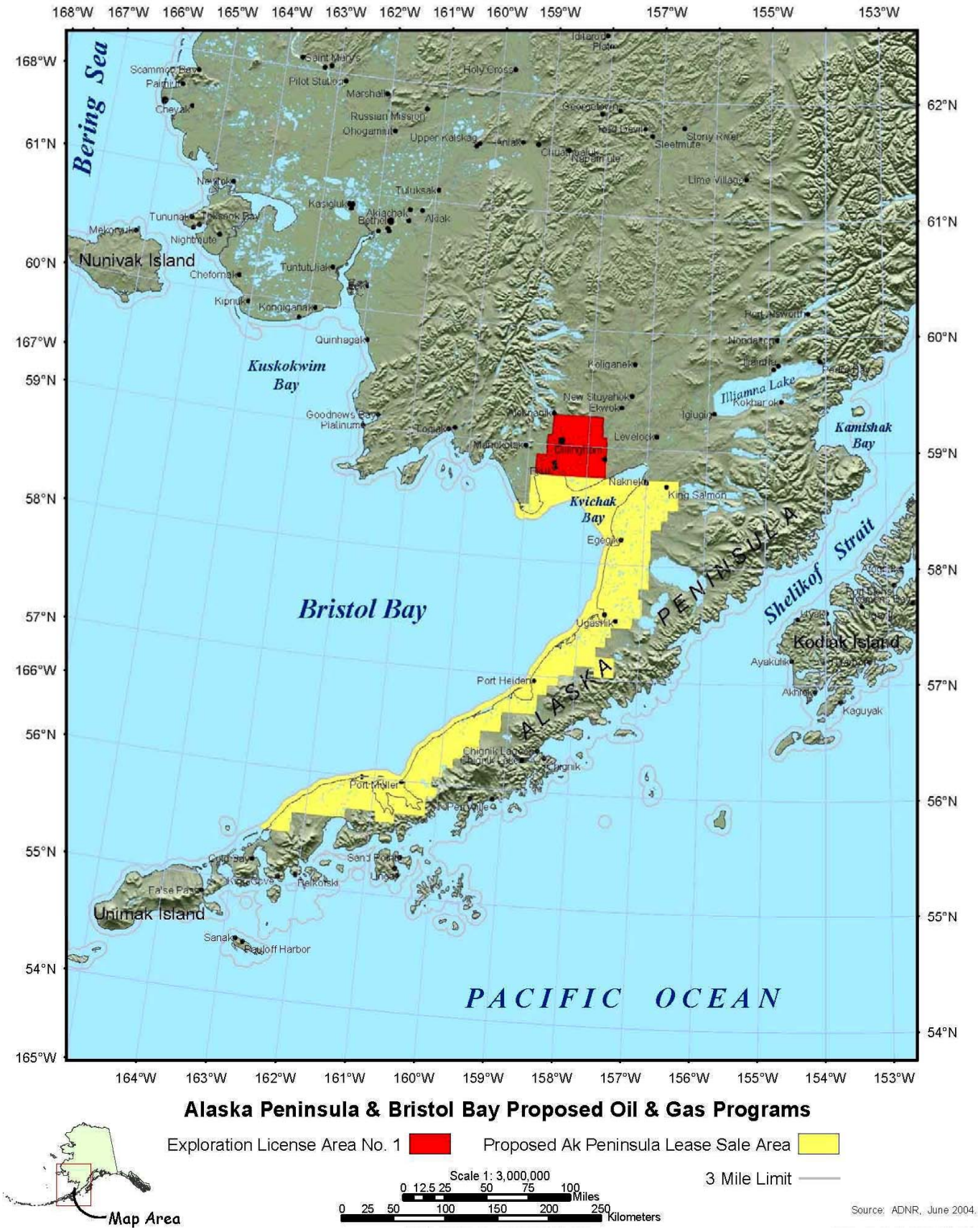
Licensee:	Bristol Shores LLC
Size:	329,113 Acres
Exploration Commitment:	$3,200,000
Term:	7 years
Effective Date:	Not Yet Issued



Current Exploration License Areas






Bering Sea
Nunivak Island
Kuskokwim Bay
Bristol Bay
Kvichak Bay
Illiamna Lake
Kamishak Bay
Shelikof Strait
ALASKA PENINSULA
Kodiak Island
Unimak Island
PACIFIC OCEAN
Alaska Peninsula & Bristol Bay Proposed Oil & Gas Programs
Exploration License Area No. 1
Proposed Ak Peninsula Lease Sale Area
3 Mile Limit
Scale 1: 3,000,000
0 12.5 25 50 75 100 Miles
0 25 50 100 150 200 250 Kilometers
Map Area
Source: ADNR, June 2004.

Exploration Incentive Credit and Tax Credit Programs

AS 38.05.180(i): Exploration Incentive Credits (EIC)

This EIC is included as a term of every lease. AS 38.05.18(i) provides for a system in which a lessee of State land drilling an exploratory well may earn credits depending on the footage drilled and the region in which the well is located. The statute also provides for an EIC for geophysical work on State land if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area. The geophysical information obtained is made public following the sale. Information is held confidential for two years, but confidentiality may be extended if the lessee meets certain requirements. The Department of Natural Resources Commissioner grants credits as high as 50 percent of the costs. Credits may be applied against State royalty and rental payments or taxes, or they may be assigned. Since the State began offering this program, lessees have earned $54.7 million in credits for exploratory drilling.

AS 41.09.010: Exploration Incentive Credits

This EIC, adopted in 1994 under AS 41.09.010, allows the Natural Resources Commissioner to grant an EIC for exploratory drilling, the drilling of a stratigraphic test well, and for geophysical work on land in the State, regardless of whether the minerals are State-owned. This program is designed to encourage oil and gas exploration within remote parts of the State and to provide a means for the State to obtain exploration data from federal, private, and Native Corporation lands. As with the Title 38 program, the credits may be applied against oil and gas royalties, rentals, lease sale bonus bids and taxes, or they may be assigned. Drilling data will be kept confidential for two years, with no extension of this period. Copies of geophysical data may be shown to interested parties by the State, but may not be transferred to third parties. Credits may be as high as 50 percent of eligible costs if performed on State land, and as high as 25 percent when performed on federal or private land. A credit may not exceed $5 million per eligible project, and the total of all credits may not exceed $30 million. Drilling credits are based upon the footage (measured depth) drilled. All activity qualifying for this EIC must be completed by July 1, 2007.

AS 43.55.025: Oil and Gas Exploration Tax Credit

This program, adopted in 2003, allows for a production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is three or more miles from the bottom hole location of a preexisting well that was spud more than 150 days, but less than 35 years, prior to the spud date of the eligible exploration well. The program also allows for a production tax credit of 40 percent of the cost of an exploratory well if the bottom hole location is 25 miles or more from the boundary of any unit under a plan of development as of July 1, 2003. The program also offers seismic exploration tax credits of 40 percent of eligible costs for those portions of activities outside of a unit that is under a plan of development or plan of exploration. Seismic data qualifying for this credit will be held confidential for 10 years and 30 days. This tax credit is transferable. This program only applies to wells drilled between July 1, 2003 and July 1, 2007.

Imnaitchiak Cherts
P. Decker

AS 43.20.043: Gas Exploration and Development Tax Credit

This program, adopted in 2003, is applicable only to operators and working interest owners engaged in exploration for and development of gas resources and reserves south of 68 degrees North latitude (excludes North Slope and Beaufort Sea). The program allows for a 10 percent tax credit equivalent of qualified capital investments made after June 30, 2003, and 10 percent of the annual cost of activity in the State during each tax year. The total allowable yearly tax credit may not exceed 50 percent of the taxpayer's total tax liability. Unused tax credits may be carried forward for up to five years. Credit is

transferable only as part of a conveyance, assignment, or transfer of the taxpayer's business. Credit under this program may be used in conjunction with any other credit authorized by AS 43.20, but not for tax credit or royalty modification provided under any other title. This program expires January 1, 2013.

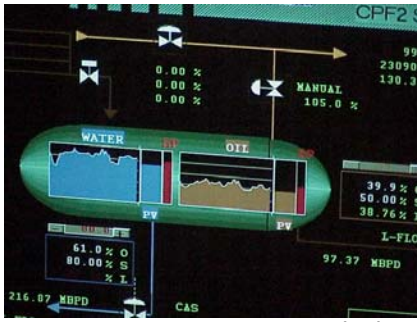
Royalty Reduction

Since 1995, Alaska law has allowed the Commissioner of Natural Resources to adjust the royalty reserved to the State in order to encourage otherwise uneconomic production of oil and gas. If a delineated field or pool has not previously produced, the royalty can be lowered to 5 percent. If an existing producing field or pool, the royalty may be reduced to as low as 3 percent in order to prolong its economic life as costs per barrel or barrel equivalent increase. In order to establish production of shut-in oil or gas, the royalty may also be reduced to as low as 3 percent. These royalty reduction provisions expire on July 1, 2015.

Discovery Royalty

Alaska law permits the granting of reduced royalty for wells in the Cook Inlet sedimentary basin that have discovered oil or gas in a previously undiscovered oil or gas pool, providing that the wells are capable of producing in paying quantities. The discovery royalty is established at 5 percent for 10 years following the discovery of a pool. The discovery royalty applies to all oil or gas from that pool that is attributable to the lease.

B. Webb



S. Schmitz

Cook Inlet Royalty Reduction

In 1998 the governor signed legislation granting a 5 percent temporary royalty rate on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first ten years of production from six specified fields in the Cook Inlet sedimentary basin. The six fields eligible for royalty reduction were discovered before January 1, 1988 and have been undeveloped or shut-in. The fields identified in the law are Falls Creek; Nicolai Creek; North Fork; Point Starichkof; Redoubt Shoal; and West Foreland. Production from these fields had to begin before January 1, 2004 to be eligible for the royalty reduction.

Section Three

Oil and Gas Units

North Slope
Cook Inlet
Non-Unitized Production Fields and Pools

Oil and Gas Units

TABLE 3.1 OIL & GAS UNITS

NORTH SLOPE WEST

Colville River
Kuparuk River
Oooguruk
Nikaitchuq
Tuvaaq

NORTH SLOPE CENTRAL

Milne Point
Prudhoe Bay
Northstar
Duck Island

NORTH SLOPE EAST

Badami
Point Thomson

COOK INLET NORTH

Pioneer
Stump Lake
Lewis River
Pretty Creek
Beluga River
Three Mile Creek
North Cook Inlet

COOK INLET CENTRAL

South Granite Point
Nicolai Creek
North Trading Bay
Trading Bay
West McArthur River
South Middle Ground Shoal
Redoubt
Birch Hill
Swanson River
Beaver Creek
Sterling
Cannery Loop
Kenai

COOK INLET SOUTH

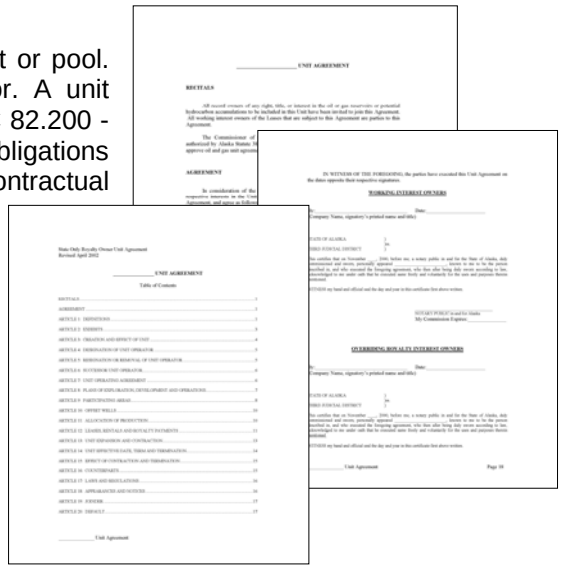
Kasilof
Ninilchik
South Ninilchik
Deep Creek
Nikolaevsk
Cosmopolitan
North Fork

Oil and Gas Units

Unitization

Unitization is the grouping or pooling of working interest and royalty ownership in oil and gas leases that overlay a common petroleum reservoir. It is a method for developing an oil or gas pool that maximizes ultimate recovery, prevents economic and physical waste, and protects the rights of all parties with an ownership interest in the accumulation. When leases are unitized, operators can eliminate redundancy and waste by sharing infrastructure and facilities, splitting development costs fairly, and adopting unified reservoir management plans. Without unitization, competitive development can result in overly dense drilling, rapid loss of reservoir pressure, and undesired production of formation fluids. Unitization minimizes impacts to the environment, protects the value of leases, and ensures efficient and equitable recovery of hydrocarbons.

Unit Formation



The unitization process begins when lessees identify a prospect or pool. The lessees in the proposed unit area select a Unit Operator. A unit operator must be qualified to hold a lease as provided in 11 AAC 82.200 - 11 AAC 82.205 , and must be qualified to fulfill the duties and obligations prescribed in the Unit Agreement. A Unit Agreement defines a contractual relationship between the state, the royalty owners, and the working interest owners of the oil and gas leases included in the unit. The Unit Operator and the state negotiate the terms of the Unit Plan of Exploration or Development for the entire unit area, and the boundaries of the unit area (11 AAC 83.341). All lessees who hold an interest in the reservoir must be invited to join the unit. The Commissioner of the Alaska Department of Natural Resources then publishes a Decision and Finding approving or disapproving the unit application. Unitization extends a lease beyond its initial primary term.

Participating Areas

After delineation drilling and testing, the Unit Operator proposes a participating area within the boundaries of the unit. The Unit Operator must submit a participating area application 90-days before sustained production from a reservoir. Only those lands known to be capable of producing in paying quantities or capable of contributing to production are included in the participating area (11 AAC 83.351). The Unit Operator and state agree on a tract allocation schedule for leases in the participating area. Production volumes and costs are allocated to each tract. An oil and gas unit can have one or more participating areas within its boundaries depending on the geology of the area. Participating areas are described laterally and limited or defined by depth. After a stated period of time, usually 5 or 10 years to explore and delineate the pools in the unit, the unit boundary contracts down to the area that is contributing to production. The boundaries of the participating area must conform as close as possible to the boundaries of the oil or gas pool.

Chelatna River
C. Beaty

Unitization Criteria

The Director considers the following criteria when evaluating a unit or participating area application. Does the application,

- promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;
- promote the prevention of economic and physical waste; and
- provide for the protection of all parties of interest, including the state.

In evaluating the above criteria, the Director considers

- the environmental costs and benefits of unitized exploration or development;
- the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;
- prior exploration activities in the proposed unit area;
- the applicant's plans for exploration or development of the unit area;
- the economic costs and benefits to the state; and
- any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

The Unitization process takes about 100 days from the time of filing a complete unit application.

A complete application includes:

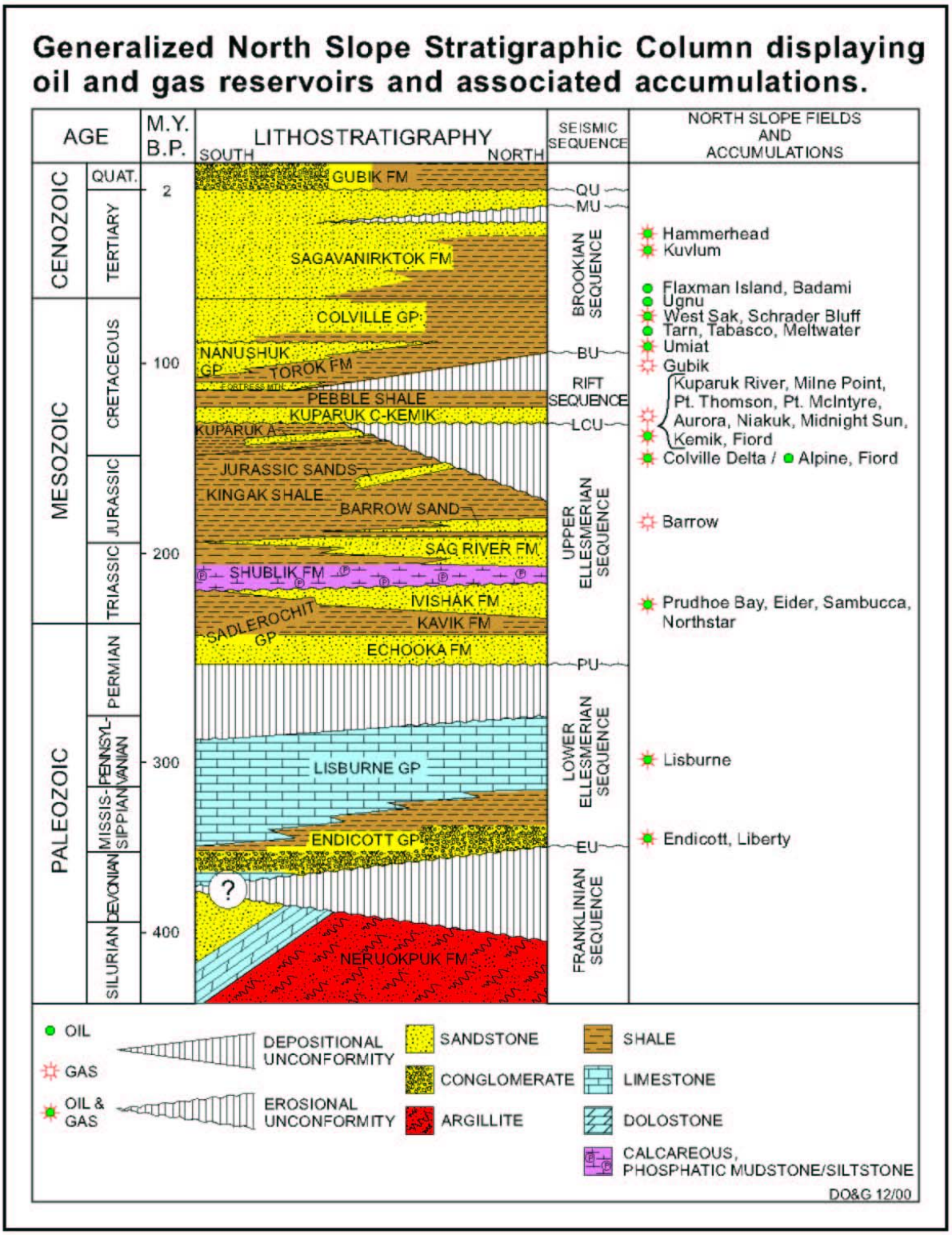
1)the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343 , executed by the proper parties;
2) the unit operating agreement executed by the working-interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;
3) evidence of reasonable effort made to obtain Joinder of any proper party who has refused to join the unit agreement;
4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data, directly supporting the application;
5) an explanation of proposed modifications, if any, of the standard state unit agreement form; and
6) the application fee prescribed by 11 AAC 05.010

Within 10-days of receipt of a complete application, a public notice is published initiating a 30-day comment period.

Plans of Exploration and Development

The Unit Operator and state must also agree on an initial Unit Plan of Exploration or Development 11 AAC 83.343. In concert with the Unit Agreement and Plans of Exploration, Development and Operation, a Unit Operating Agreement is drafted describing how expenses and revenues are distributed or paid among the Working Interest Owners in the unit. Unit Operators must submit an annual Plan of Development for approval (11 AAC 83.343). Often unit areas are explored and developed at the same time. Failure to meet the goals, objectives, and commitments in the Plan of Exploration or Development can result in default and unit termination.

Generalized North Slope Stratigraphic Column



North Slope

Alpine CD #2
S. Schmitz

Colville River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska and Arctic Slope Regional Corporation
Operator:	ConocoPhillips (Alaska), Inc.
State Acres:	88,766
First Production:	2000

Alpine PA

Status:	Producing
Discovery:	1994, ARCO Bergschrund #1
Reservoir:	Jurassic Kingak Formation, Alpine sandstone (-6,850 ft.)
Working Interest:	ConocoPhillips (Alaska), Inc. 56% Anadarko Petroleum Corp. 22% Phillips Alpine AK, LLC 22%

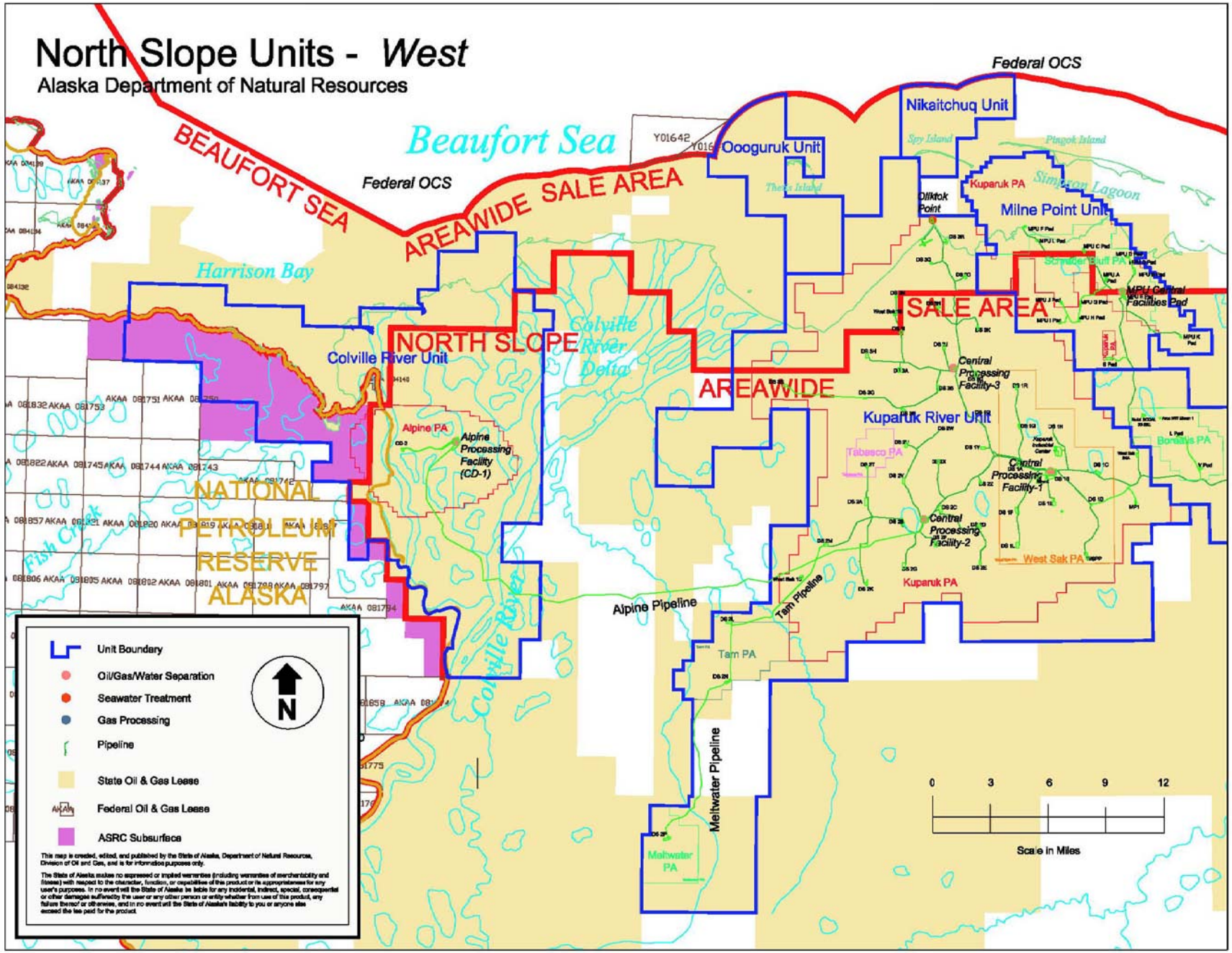
Nanuk Tract Operation

Status:	Test production
Discovery:	2000, ARCO Nanuk #2
Reservoir:	Cretaceous Torok Fm., Nanuq sandstone (-6,140 ft.)
Working Interest:	ConocoPhillips (Alaska), Inc. 56% Anadarko Petroleum Corp. 22% Phillips Alpine AK, LLC 22%

Fiord Discovery

Status:	Undeveloped
Discovery:	1992, ARCO Fiord #1
Reservoir:	Kuparuk/Nechelik sandstones (-6,890 ft. and -7,400 ft.)
Working Interest:	ConocoPhillips (Alaska), Inc. 56% Anadarko Petroleum Corp. 22% Phillips Alpine AK, LLC 22%

Alpine expansion loop
S. Schmitz


North Slope Units - West
Alaska Department of Natural Resources
Beaufort Sea
BEAUFORT SEA
AREAWIDE SALE AREA
Federal OCS
Federal OCS
Harrison Bay
Nikaitchuq Unit
Ooguruk Unit
Spy Island
Pingok Island
Thetis Island
Kuparuk PA
Simpson Lagoon
Oliktok Point
Milne Point Unit
Schrader Bluff PA
MPU Central Facilities Pad
SALE AREA
NORTH SLOPE
AREAWIDE
Colville River Unit
Colville River Delta
Central Processing Facility-3
Kuparuk River Unit
Alpine PA
Alpine Processing Facility (CD-1)
Tabasco PA
Central Processing Facility-1
Borealis PA
NATIONAL PETROLEUM RESERVE ALASKA
Central Processing Facility-2
West Sak PA
Kuparuk PA
Fish Creek
Colville River
Alpine Pipeline
Tarn Pipeline
Tarn PA
Meltwater Pipeline
Meltwater PA
Unit Boundary
Oil/Gas/Water Separation
Seawater Treatment
Gas Processing
Pipeline
State Oil & Gas Lease
Federal Oil & Gas Lease
ASRC Subsurface
N
0 3 6 9 12
Scale in Miles

North Slope

Kuparuk River Unit

Meltwater Pad
S. Schmitz

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	ConocoPhillips Alaska, Inc.
Acres:	276,027
First Production:	1981

Kuparuk PA

Status:	Producing
Discovery:	1969, Sinclair Ugnu #1
Reservoir:	Cretaceous Kuparuk Formation (-5,600 ft subsea)
Working Interest:	BP Exploration (Alaska), Inc. 39%
	ConocoPhillips 55%
	Unocal 5%
	XTO Energy, Inc./ExxonMobil 1%

Meltwater PA

Status:	Producing
Discovery:	2000, ARCO Meltwater North #1
Reservoir:	Late Cretaceous Seabee Fm. Bermuda/Cairn sand)
Working: Interest	BP Exploration (Alaska), Inc. 39%
	ConocoPhillips 55%
	Unocal 5%
	XTO Energy, Inc./ExxonMobil 1%

Hot Ice
B. Webb

Tabasco PA

Status:	Producing
Discovery:	1986, ARCO Kuparuk River Unit #2T-02
Reservoir:	Cretaceous Colville Group Tabasco sand
Working Interest:	BP Exploration (Alaska), Inc. 39%
	ConocoPhillips 55%
	Unocal 5%
	XTO Energy, Inc./ExxonMobil 1%

Tarn PA

Status:	Producing
Discovery:	1991, ARCO KRU Bermuda #3
Reservoir:	Late Cretaceous Seabee Fm., Bermuda sand (-4,376 to -5,990 ft)
Working Interest:	BP Exploration (Alaska), Inc. 39%
	ConocoPhillips 55%
	Unocal 5%
	XTO Energy, Inc./ExxonMobil 1%

North Slope

Kuparuk River Unit, Cont.

West Sak PA

Status:	Producing
Discovery:	West Sak River State #1
Reservoir:	Cretaceous Colville Group Tabasco sand
Working Interest:	BP Exploration (Alaska), Inc. 39% ConocoPhillips Alaska, Inc. 55% XTO Energy, Inc./ExxonMobil 1% Unocal 5%

Oooguruk Unit

Status:	Exploration
Royalty Ownership:	State of Alaska
Operator:	Pioneer Natural Resources, Inc.
Acres:	20,394
Working Interest:	Pioneer Alaska, Inc. 70% Armstrong Alaska, Inc. 30%

Nabors Rig 27E
C. Ruff

Nikaitchuq Unit

Status:	Exploration
Royalty Ownership:	State of Alaska
Operator:	Pioneer Natural Resources, Inc.
Acres:	12,047
Working Interest:	Kerr-McGee Oil & Gas Corp. 70% Armstrong Alaska, Inc. 30%

Tuvaaq Unit

Status:	Exploration
Royalty Ownership:	State of Alaska
Operator:	Pioneer Natural Resources, Inc.
Acres:	14,561
Working Interest:	Armstrong Alaska, Inc. 100%

North Slope

Milne Point Unit F-Pad
S. Schmitz

Milne Point Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	68,830
First Production:	1985

Kuparuk PA

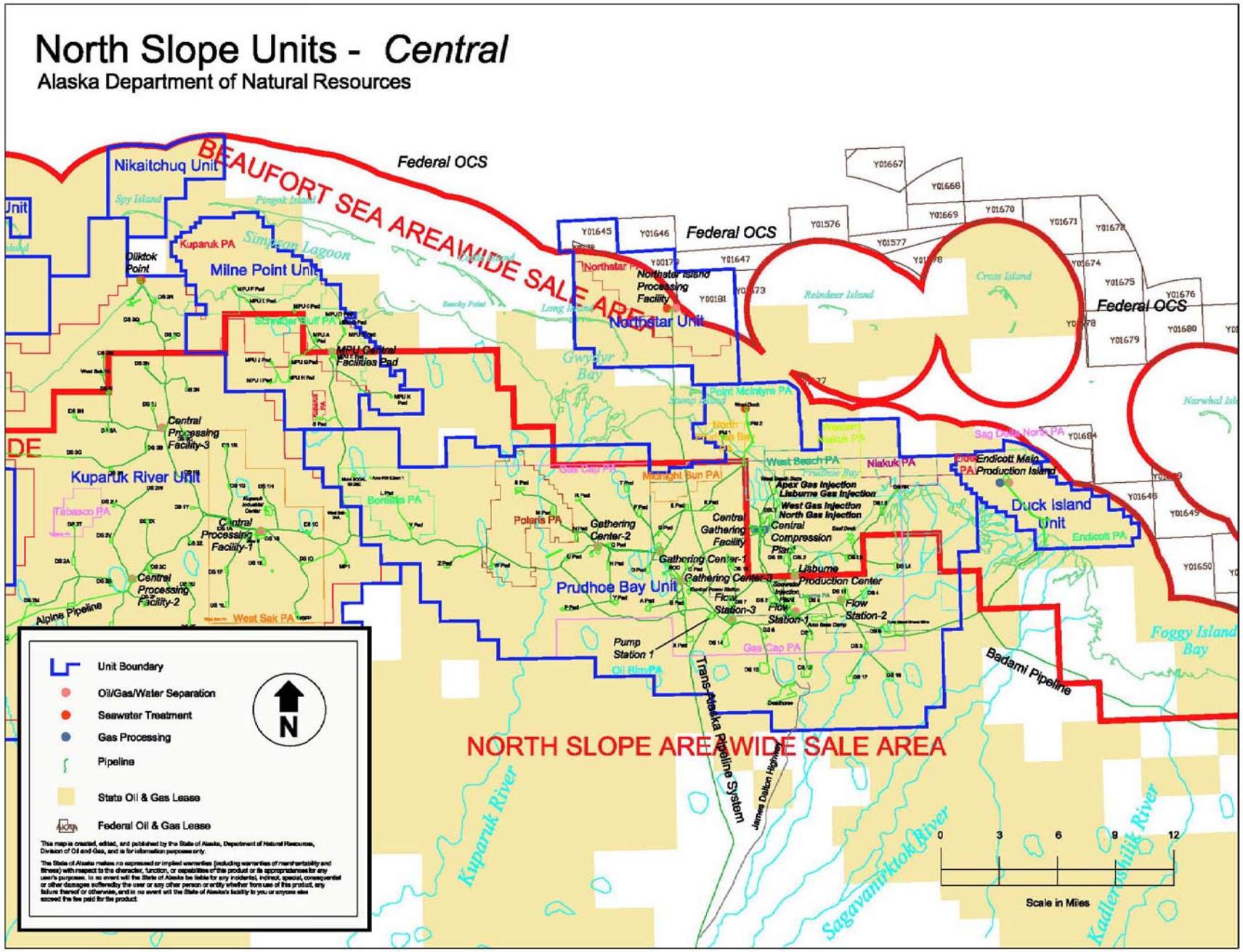
Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25 1993, BP Cascade #1
Reservoir:	Cretaceous Kuparuk Formation (-7,200 ft subsea)
Working Interest:	BP Exploration (Alaska), Inc. 100%

Schrader Bluff PA

Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25
Reservoir:	Cretaceous Colville Group Schrader Bluff Fm.
Working Interest:	BP Exploration (Alaska), Inc. 100%

Sag River Tract Operations (Undefined Pool)

Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25
Reservoir:	Sag River and Ivishak formations
Working Interest:	BP Exploration (Alaska), Inc. 100%


North Slope Units - Central
Alaska Department of Natural Resources
BEAUFORT SEA AREAWIDE SALE AREA
Federal OCS
Nikaitchuq Unit
Kuparuk PA
Milne Point Unit
Oliktok Point
Schrader Bluff PA
MPU Central Facilities Pad
Northstar Island Processing Facility
Northstar Unit
Reindeer Island
Cross Island
Point McIntyre PA
Central Processing Facility-3
Kuparuk River Unit
Tabasco PA
Central Processing Facility-1
Central Processing Facility-2
Alpine Pipeline
West Sak PA
Bermuda PA
Polaris PA
Gathering Center-2
Gathering Center-1
Gathering Center-3
Central Gathering Facility
Central Compression Plant
Apex Gas Injection
Lisburne Gas Injection
West Gas Injection
North Gas Injection
Lisburne Production Center
Prudhoe Bay Unit
Flow Station-1
Flow Station-2
Flow Station-3
Pump Station 1
Gas Cap PA
Oil Rim PA
Midnight Sun PA
West Beach PA
Niakuk PA
Endicott Main PA
Endicott Production Island
Duck Island Unit
Endicott PA
Sag Delta North PA
Badami Pipeline
Foggy Island Bay
Trans-Alaska Pipeline System
James Dalton Highway
NORTH SLOPE AREAWIDE SALE AREA
Kuparuk River
Sagavanirktok River
Kadleroshilik River
Unit Boundary
Oil/Gas/Water Separation
Seawater Treatment
Gas Processing
Pipeline
State Oil & Gas Lease
Federal Oil & Gas Lease
N
0 3 6 9 12
Scale in Miles

North Slope

Central Gas Facility
S. Schmitz

Prudhoe Bay Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	247,477
First Production:	1977
Working Interest: (*Aligned for all PA's ~December 2001)*	ExxonMobil Alaska Production,Inc. 36.39% ConocoPhillips Alaska, Inc. 36.07% BP Exploration (Alaska), Inc. 26.36% ChevronTexaco 1.16% Forest Oil Corporation 0.02%

Aurora PA

Status:	Producing
Discovery:	1969, Mobil North Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Borealis PA

Status:	Producing
Discovery:	1969, Mobil West Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Gas Cap PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Triassic Ivishak Sandstone (-8,800 ft subsea)

Lisburne PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Mississippian Lisburne Group

MIX Module
S. Schmitz

Midnight Sun PA

Status:	Producing
Discovery:	1997, BP Prudhoe Bay Un MDS #E-100
Reservoir:	Cretaceous Kuparuk Formation

Niakuk PA

Status:	Producing
Discovery:	1985, BP Niakuk #5
Reservoir:	Cretaceous Kuparuk Formation (-9,350 ft.)

Oliktok Point
S. Schmitz

Prudhoe Bay Unit, Cont.

North Prudhoe Bay PA

Status: Producing
Discovery: 1970, ARCO North Prudhoe Bay State #1
Reservoir: Triassic Sadlerochit Group

Oil Rim PA

Status: Producing
Discovery: 1968, Richfield Prudhoe Bay State #1
Reservoir: Triassic Ivishak sandstone (-8,800 ft subsea)

Polaris PA

Status: Producing
Discovery: 1969, Mobil North Kuparuk State #1
Reservoir: Cretaceous Colville Group, Schrader Bluff Fm.

Point McIntyre PA

Status: Producing
Discovery: 1988, ARCO Pt. McIntryre #3A
Reservoir: Cretaceous Kuparuk Formation

West Beach PA

Status: Producing
Discovery: 1976, ARCO West Beach #3
Reservoir: Cretaceous Kuparuk Formation

Deadhorse
S. Schmitz

Western Niakuk PA

Status: Producing
Discovery: 1985, BP Niakuk #5
Reservoir: Cretaceous Kuparuk Formation (-9,350 ft.)

Orion PA

Status: Producing
Discovery: 1968, Mobil Kuparuk State #1
Reservoir: Cretaceous Schrader Bluff Fm (-4,500 ft.ss)

North Slope

Northstar
C. Ruff

Northstar Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska/Federal
Operator:	BP Exploration (Alaska), Inc.
Acres:	23,343
First Production:	2001

Northstar PA

Status:	Producing
Discovery:	1984, Shell BF-47 (Seal Island) #1
Reservoir:	Triassic Ivishak Sandstone (-11,000 ft. subsea)
Working Interest:	BP Exploration (Alaska), Inc. 100%

Northstar pipeline Construction
S. Schmitz

North Slope

Tundra Moss Companion
S. Schmitz

Duck Island Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	28,189
First Production:	1994

Eider PA

Status:	Producing
Discovery:	1998, BP Duck Island Unit MPI #2-56/EID
Reservoir:	Triassic Ivishak Sandstone
Working Interest:	BP Exploration (Alaska), Inc. 100%

Endicott PA

Status:	Producing
Discovery:	1978, Sohio Sag Delta 34633 #4
Reservoir:	Mississippian Kekiktuk Conglomerate (-10,000 ft subsea)
Working Interest:	BP Exploration (Alaska), Inc. 68%
	ExxonMobil 21%
	Unocal 10%
	Doyon Ltd./NANA Regional Corporation/ConocoPhillips 1%

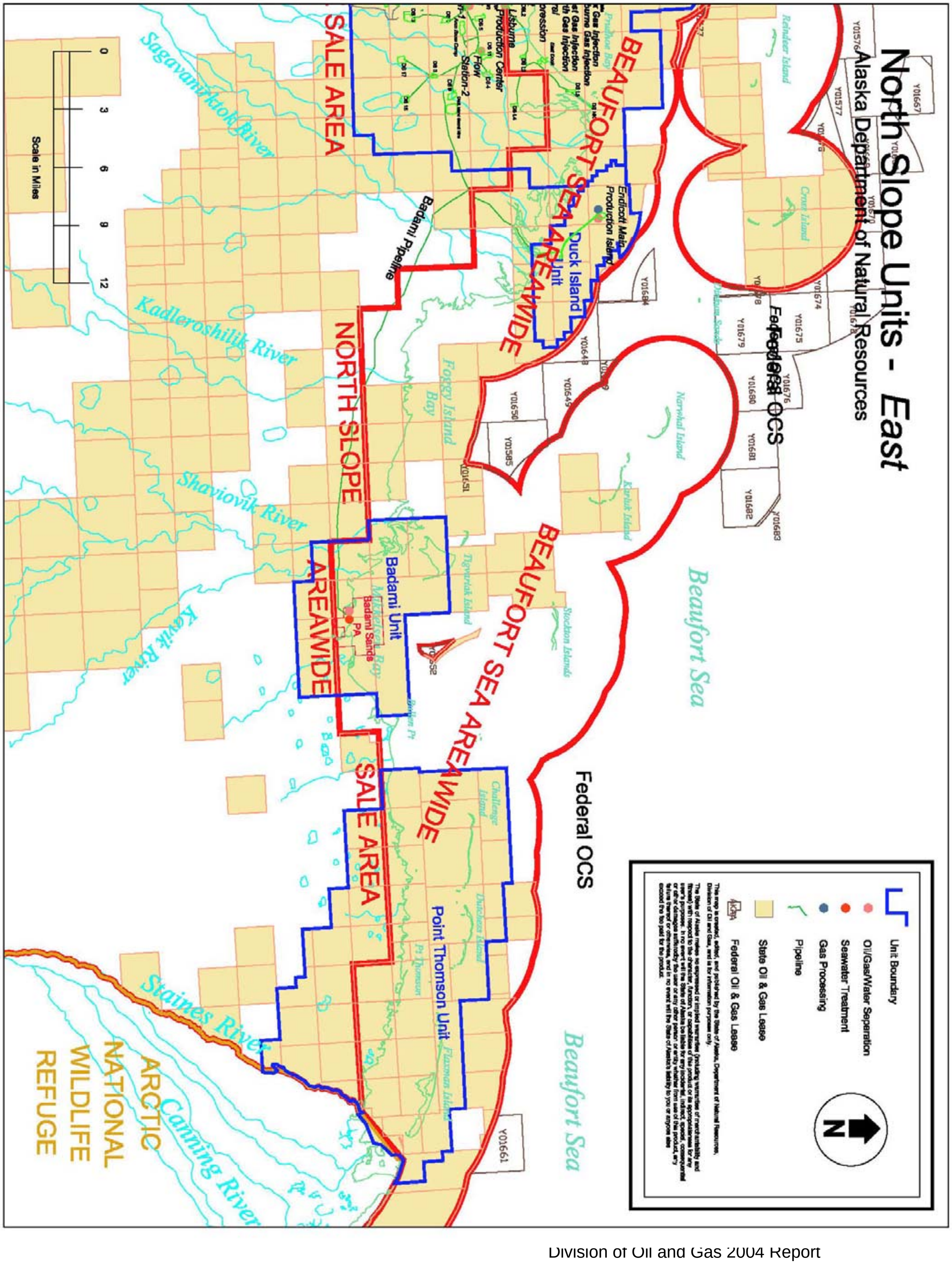
Sag Delta North PA

Status:	Producing
Discovery:	1982, Sohio Sag Delta #9
Reservoir:	Mississippian Alaphah Limestone
Working Interest:	BP Exploration (Alaska), Inc. 98%
	NANA Regional Corporation/Doyon Ltd. 2%

Brooks Range
S. Schmitz

Barrier Islands
B. Webb

Canning River well
B. Webb


North Slope Units - East
Alaska Department of Natural Resources
Unit Boundary
Oil/Gas/Water Seperation
Seawater Treatment
Gas Processing
Pipeline
State Oil & Gas Lease
Federal Oil & Gas Lease
BEAUFORT SEA AREAWIDE
NORTH SLOPE AREAWIDE
SALE AREA
Federal OCS
Beaufort Sea
Duck Island Unit
Endicott Main Production Island
Badami Unit
Badami Sands
Badami Pipeline
Point Thomson Unit
ARCTIC NATIONAL WILDLIFE REFUGE
Sagavanirktok River
Kadleroshilik River
Shaviovik River
Kavik River
Staines River
Canning River
Scale in Miles
0
3
6
9
12

North Slope

Badami Pad
B. Webb

Badami Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	BP Exploration (Alaska), Inc.
Acres:	37,401
Working Interest:	BP Exploration (Alaska), Inc. 100%

Badami Sands PA

Status:	Suspended
Discovery:	1990, Conoco Badami #1
Reservoir:	Tertiary Canning Formation
	Badami sandstone (-9,900 ft)
Working Interest:	BP Exploration (Alaska), Inc. 100%

Arctic Coastal Plain
B. Webb

North Slope

Point Thomson Unit

Exploration site before reclamation
B. Webb

Status:	Development
Royalty Ownership:	State of Alaska
Operator:	ExxonMobil
Acres:	106,184
First Production:	~2008
Discovery:	1977, Exxon Pt. Thomson #1
Working Interest:	BPAmerica 42%
	ExxonMobil 37%
	Chevron 19%
	Others <3%

Point Thomson Sands Discovery

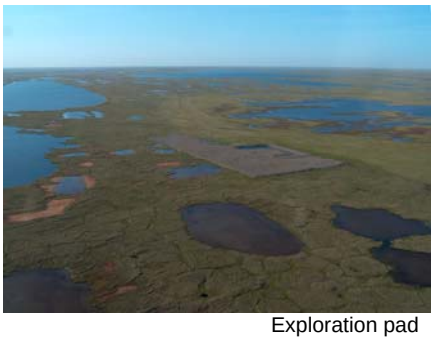
Status:	Undeveloped
Discovery:	1977, Exxon Pt. Thomson #1
Reservoir:	Lower Cretaceous Thomson sandstone (-12,834 ft.)

Flaxman Discovery

Status:	Undeveloped
Discovery:	1975, Exxon Alaska State A #1
Reservoir:	Tertiary Flaxman sand (-12,565 ft.)

Sourdough Discovery

Status:	Undeveloped
Discovery:	1994, BP Sourdough #2
Reservoir:	Reservoir information not available



Exploration pad
B. Webb

Cook Inlet

Pioneer Peak
ADCED

Pioneer Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/Federal/ Cook Inlet Regional Corporation/ Alaska Mental Health Trust/ University of Alaska/Fee
Operator:	Evergreen Resources, Inc.
State Acres:	37,885
Reservoir:	Tertiary Tyonek Formation Coalbed methane target
Working Interest:	Evergreen Resources Alaska, Inc. 100%

Stump Lake Unit
B. Havelock

Stump Lake Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	4,880
First Production:	1990

Stump Lake Gas Pool #1 PA

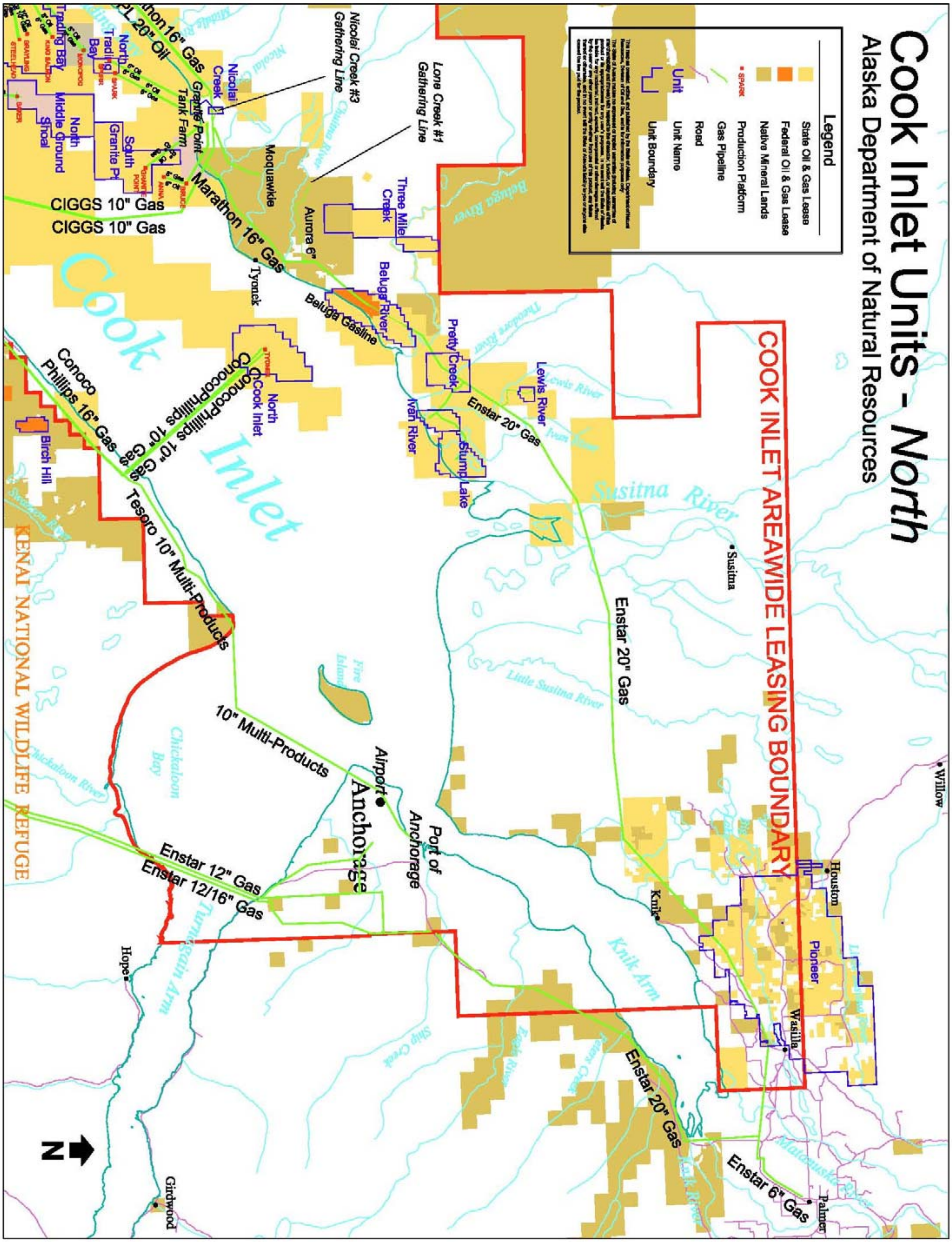
Status:	Shut-in 1978, Restart 1990, Shut-in 2000
Discovery:	1978, Chevron Stump Lake Unit #41-33
Reservoir:	Tertiary Beluga Formation
Working Interest:	Unocal 100%

Ivan River Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	2,291
First Production:	1990

Ivan River Gas Pool #1 PA

Status:	Producing Gas
Discovery:	1966, Chevron Ivan River Unit #44-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 100%


Cook Inlet Units - North
Alaska Department of Natural Resources
Legend
State Oil & Gas Lease
Federal Oil & Gas Lease
Native Mineral Lands
Production Platform
Gas Pipeline
Road
Unit Name
Unit Boundary
Unit
COOK INLET AREAWIDE LEASING BOUNDARY
KENAI NATIONAL WILDLIFE REFUGE
Cook
Inlet
Nicolai Creek #3 Gathering Line
Lone Creek #1 Gathering Line
Nicolai Creek
North Trading Bay
Trading Bay
Granite Point
Tank Farm
North Middle Ground Shoal
South Granite Pt
Moquawkie
Three Mile Creek
Aurora 6"
Marathon 16" Gas
CIGGS 10" Gas
CIGGS 10" Gas
Tyonek
Beluga River
Beluga Gasline
Pretty Creek
Lewis River
Ivan River
Stump Lake
North Cook Inlet
Enstar 20" Gas
ConocoPhillips 10" Gas
ConocoPhillips 10" Gas
Conoco Phillips 16" Gas
Birch Hill
Tesoro 10" Multi-Products
10" Multi-Products
Susitna River
Susitna
Little Susitna River
Enstar 20" Gas
Airport
Anchorage
Port of Anchorage
Chickaloon Bay
Enstar 12" Gas
Enstar 12/16" Gas
Turnagain Arm
Hope
Girdwood
Knik Arm
Knik
Houston
Pioneer
Wasilla
Willow
Enstar 20" Gas
Enstar 6" Gas
Palmer
N

Cook Inlet

Lewis River Pad
B. Havelock

Lewis River Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	720
First Production:	1984

Lewis River PA #1

Status:	Producing
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Unocal 100%

Lewis River PA #2

Status:	Producing
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Unocal 100%

Pretty Creek Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	4,579
First Production:	1986

Beluga PA

Status:	Suspended
Discovery:	1979, Chevron Pretty Creek Unit #2
Reservoir:	Tertiary Beluga Formation
Working Interest:	Unocal 100%

Cook Inlet

Beluga River Unit


B. Havelock

Status:	Producing Gas
Royalty Ownership:	State of Alaska/Federal/Fee
Operator:	ConocoPhillips Alaska, Inc.
Acres:	12,743
First Production:	1968

Beluga-Sterling Gas Pool PA

Status:	Producing gas
Discovery:	1962, Chevron Beluga River Unit 212-35 #1
Reservoir:	Tertiary Sterling Formation
Working Interest:	Chevron USA $33^{1/3}$%
	ConocoPhillips Alaska, Inc. $33^{1/3}$%
	Municipality of Anchorage $33^{1/3}$%

Three Mile Creek Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI
Operator:	Aurora Gas, LLC.
Acres:	12,743

North Cook Inlet Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska
Operator:	ConocoPhillips Petroleum Company
Acres:	23,368
First Production:	1970

North Cook Inlet Initial PA

Status:	Producing gas
Discovery:	1962, Pan Am Cook Inlet State 17589 #1
Reservoir:	Tertiary Tyonek, Beluga and Sterling formations
Working Interest:	ConocoPhillips Petroleum Company 100%

Cook Inlet

South Granite Point Unit

Anna Metering
B. Havelock

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	10,209
First Production:	1967

Granite Point Sands PA

Status:	Producing
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	ExxonMobil 75%
	Unocal 25%

Hemlock PA

Status:	Producing
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	ExxonMobil 75%
	Unocal 25%

Nicolai Creek Unit

Nicloai Creek drilling
B. Havelock

Status:	Producing Gas
Royalty Ownership:	State of Alaska/Federal
Operator:	Aurora Gas, LLC
Acres:	698
First Production:	Shut-in 1977, Restart 2001

Nicolai Creek Gas Pool "A" PA

Status:	Shut-In
Discovery:	1966, Texaco Nicolai Creek State #1A
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Aurora Gas, LLC 100%

Nicolai Creek Gas Pool "B" PA

Status:	Producing gas
Discovery:	1967, Texaco Nicolai Creek Unit #3
Reservoir:	Tertiary Tyonek and Beluga formations
Working Interest:	Aurora Gas, LLC 100%

Cook Inlet

Redoubt Unit

B. Havelock

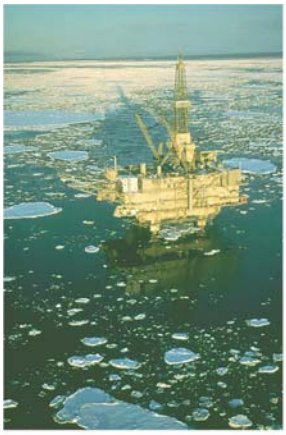
Status:	Development
Royalty Ownership:	State of Alaska
Operator:	Forest Oil Company
Acres:	23,526
First Production:	December 2002

Hemlock PA

Status:	Producing Oil
Discovery:	1968, Pan Am Redoubt Shoal Unit #2
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Forest Oil Corporation 100%

Trading Bay Unit

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	17.859
First Production:	1967



CIRCAC

Grayling Gas Sands PA

Status:	Producing gas
Discovery:	1968, Trading Bay Unit #G-18
Reservoir:	Tertiary Tyonek Formation (-2,500 to -6,500 ft. subsea)
Working Interest:	Unocal 48.8% Marathon Oil Company 51.2%

McArthur River Hemlock Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Unocal 46.8% Forest Oil Corporation 53.2%

McArthur River Middle Kenai G Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 46.8% Forest Oil Corporation 53.2%

McArthur River West Foreland Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary West Foreland Formation
Working Interest:	Unocal 46.8%, Forest Oil Corporation 53.2%

Cook Inlet

Monopod Platform
B. Webb

North Trading Bay Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Marathon Oil Company
Acres:	1,120
First Production:	Shut-in 1992

Hemlock and "G" Formation PA

Status:	Suspended
Discovery:	1965, Chevron Trading Bay #1A
Reservoir:	Tertiary Hemlock and Tyonek formations
Working Interest:	Marathon Oil Company 81%
	Unocal 19%

West McArthur River Unit

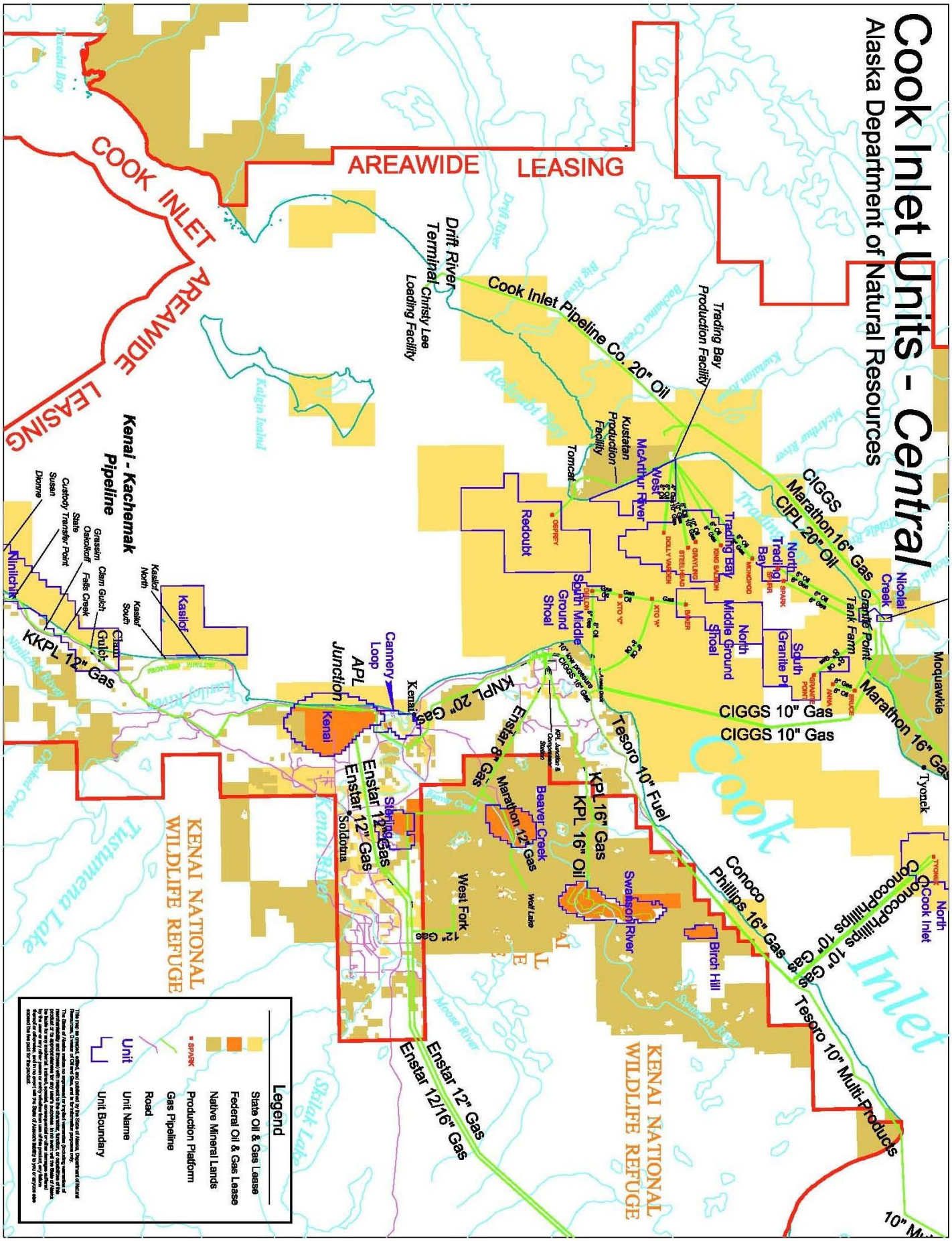
Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Forest Oil Corporation
Acres:	6,330
First Production:	1994

Area 1 PA

Status:	Producing oil
Discovery:	1991, Stewart West McArthur River #1
Reservoir:	Tertiary Hemlock Conglomerate
Working Interest:	Forest Oil Corporation 100%

West Foreland Field

Status:	Producing gas
Discovery:	1962, West Foreland #1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Forest Oil Corporation 100%


Cook Inlet Units - Central
Alaska Department of Natural Resources
COOK INLET AREAWIDE LEASING
AREAWIDE LEASING
Drift River Terminal
Christy Lee Loading Facility
Cook Inlet Pipeline Co. 20" Oil
Trading Bay Production Facility
Kustatan Production Facility
Tomcat
McArthur River West
Redoubt
Trading Bay
North Trading Bay
Granite Point Tank Farm
CIGGS Marathon 16" Gas
CIPL 20" Oil
Nicolai Creek
Moquawkie
Tyonek
Marathon 16" Gas
South Granite Pt
North Middle Ground Shoal
South Middle Ground Shoal
Kenai - Kachemak Pipeline
Susan Dionne
Custody Transfer Point
State
Grassim Oskolkoff
Clam Gulch
Falls Creek
Kasilof North
Kasilof South
Kasilof
Ninilchik
KKPL 12" Gas
Cannery Loop
APL Junction
Kenai
KNPL 20" Gas
Enstar 8" Gas
Tesoro 10" Fuel
CIGGS 10" Gas
CIGGS 10" Gas
KPL 16" Gas
KPL 16" Oil
Marathon 12" Gas
Beaver Creek
Swanson River
Conoco Phillips 16" Gas
ConocoPhillips 10" Gas
Cook Inlet North
Birch Hill
Tesoro 10" Multi-Products
Enstar 12" Gas
Enstar 12/16" Gas
Soldotna
Sterling
West Fork 2" Gas
KENAI NATIONAL WILDLIFE REFUGE
KENAI NATIONAL WILDLIFE REFUGE
Cook Inlet
Legend
State Oil & Gas Lease
Federal Oil & Gas Lease
Native Mineral Lands
Production Platform
Gas Pipeline
Road
Unit
Unit Name
Unit Boundary

Cook Inlet

South Middle Ground Shoal Unit

Status:	Suspended
Royalty Ownership:	State of Alaska
Operator:	Unocal
Acres:	1,160
First Production:	1967

South Middle Ground Shoal Tertiary System PA

Status:	Shut-in
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations
Working Interest:	Unocal 100%

Birch Hill Unit

Status:	Suspended
Royalty Ownership:	Federal
Operator:	ConocoPhillips Alaska, Inc.
Acres:	1,240
First Production:	Shut-in 1965

Gas Pool #1 PA

Status:	Shut-in
Discovery:	1965, Chevron Birch Hill Unit #22-25
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Unocal 79% CIRI Production Company 20% Marathon Oil Company 1%

Swanson River Unit

Status:	Producing Oil and Gas
Royalty Ownership:	Federal/CIRI
Operator:	Unocal
Acres:	7,880
First Production:	1960

"B, C, D & E" Zone Gas Pools #1 and #2 Consolidated Hemlock PA

Status:	Producing
Discovery:	1957, Richfield Swanson River Unit #34-10
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga
Working Interest:	Unocal 100%

Cook Inlet

Beaver Creek Unit

Status:	Producing Oil and Gas
Royalty Ownership:	Federal, Fee
Operator:	Marathon
Acres:	4,960
First Production:	1973

Sterling Gas, Beluga Gas, and Beaver Creek Oil Pools

Status:	Producing oil and gas
Discovery:	1972, Marathon Beaver Creek #4
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga formations
Working Interest:	Marathon Oil Company

Sterling Unit

Status:	Producing Gas
Royalty Ownership:	Federal/CIRI/State of Alaska/Fee
Operator:	Marathon Oil Company
Total Acres:	3,600
First Production:	1962

"A" Zone PA (Sterling Formation Gas Zone PA)

Status:	Producing
Discovery:	1961, UNOCAL Sterling Unit #23-15
Reservoir:	Tertiary Sterling Formation
Working Interest:	Marathon Oil Company 100%

Lower Beluga PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Beluga Formation
Working Interest:	Marathon Oil Company 100%

Tyonek PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 100%

Cook Inlet

Cannery Loop Unit

Status:	Producing Gas
Royalty Ownership:	State of Alaska/Federal/CIRI/Fee
Operator:	Marathon Oil Company
Total Acres:	1,900
First Production:	1988
Working Interest:	Marathon Oil Company 100%

Beluga Formation Undifferentiated Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Beluga Formation

Sterling Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Sterling Formation

Tyonek D Zone Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Upper Tyonek Formation Undifferentiated Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Kenai River Unit

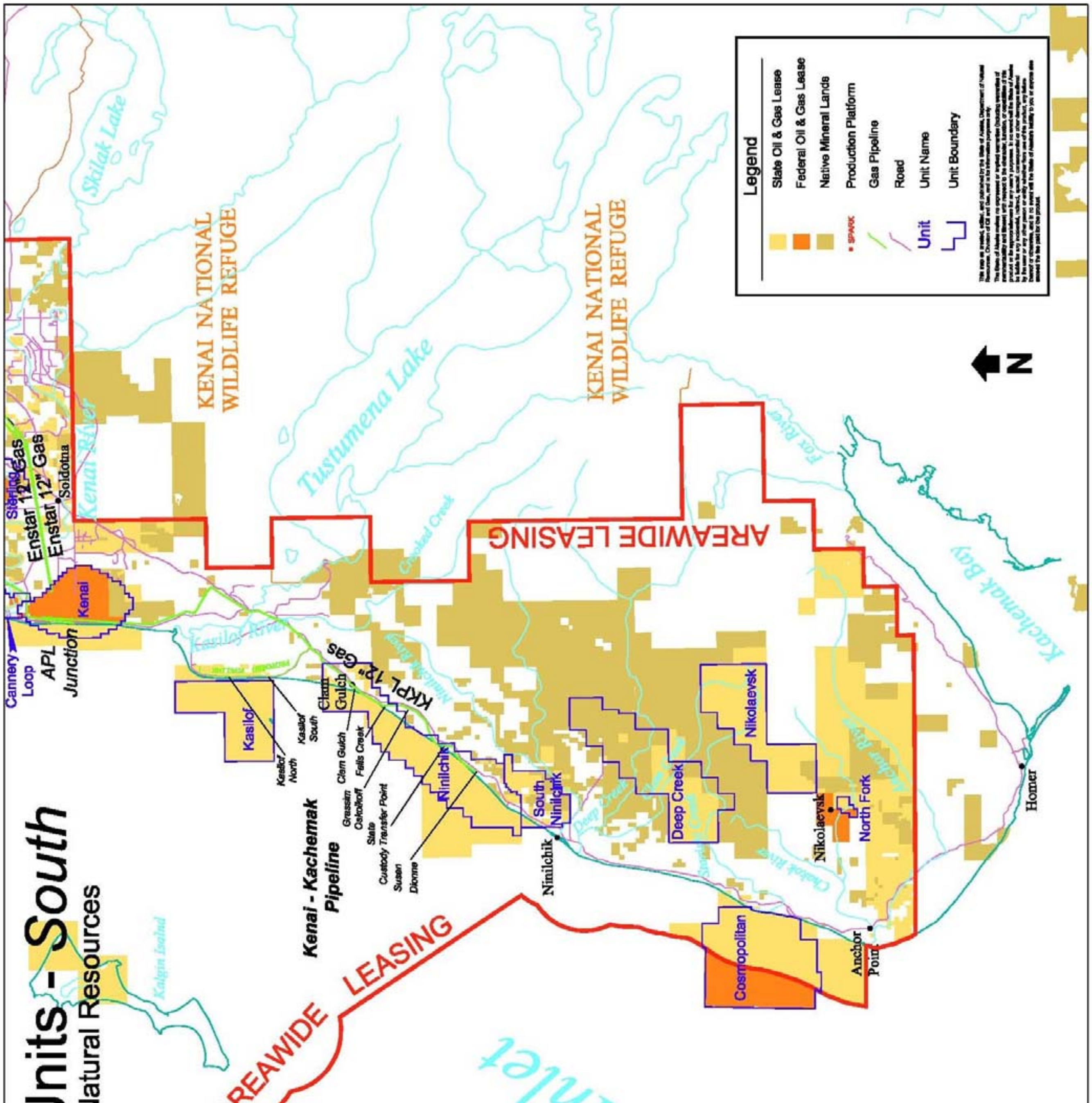
Status:	Producing Gas
Royalty Ownership:	State of Alaska/Federal/CIRI/Fee
Operator:	Marathon Oil Company
Total Acres:	8,264
First Production:	1961
Working Interest:	Marathon Oil Company ~100%

Sterling Formation Gas Zone PA (A Zone PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Sterling Formation

Beluga PA (Beluga Formation Gas Zones PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Beluga Formation (-4,595 to -5,108 ft. subsea)


Cook Inlet Units - South
Alaska Department of Natural Resources
Legend
State Oil & Gas Lease
Federal Oil & Gas Lease
Native Mineral Lands
Production Platform
Gas Pipeline
Road
Unit Name
Unit Boundary
KENAI NATIONAL WILDLIFE REFUGE
KENAI NATIONAL WILDLIFE REFUGE
AREAWIDE LEASING
COOK INLET AREAWIDE LEASING
Cook Inlet
Tustumena Lake
Skilak Lake
Kachemak Bay
Kenai - Kachemak Pipeline
KKPL 12" Gas
Enstar 12" Gas
Cannery Loop
APL Junction
Kenai
Soldotna
Kasilof
Clam Gulch
Ninilchik
South Ninilchik
Deep Creek
Nikolaevsk
North Fork
Cosmopolitan
Ninilchik
Nikolaevsk
Anchor Point
Homer

Cook Inlet

Ninilchik Unit

Status:	Gas Exploration and Production
Royalty Ownership:	State of Alaska/CIRI/Fee
Operator:	Marathon Oil Company
Total Acres:	27,860
Working Interest:	Marathon Oil Company 60%
	Unocal 40%

Falls Creek PA

Status:	Producing Gas
Discovery:	1961, Chevron Falls Creek Unit #43-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 50.44%
	Unocal 33.63%
	ConocoPhillips (Alaska), Inc. 15.93%

Grassim Oskolkoff PA

Status:	Producing Gas
Discovery:	1961, Chevron Falls Creek Unit #43-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 60%
	Unocal 40%

Susan Dionne PA

Status:	Producing Gas
Discovery:	1961, Chevron Falls Creek Unit #43-1
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Marathon Oil Company 60%
	Unocal 40%

Kenai River
B. Havelock

Kasilof Unit

Status:	Gas Exploration
Royalty Ownership:	State of Alaska
Operator:	Marathon Oil Company
Acres:	13,289

South Ninilchik Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI/Fee
Operator:	Unocal
Acres:	6,998
Working Interest:	Unocal 100%

Cook Inlet

Deep Creek Unit

Nikolaevsk Pad
C. Ruff

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI
Operator:	Unocal
Acres:	22,617
Working Interest:	Unocal 100%

Happy Valley Discovery

Status:	Exploration
Discovery:	2003, Happy Valley #1

Nikolaevsk Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/CIRI
Operator:	Unocal
Acres:	16,589
Working Interest:	Unocal. 100%

Cosmopolitan Unit

Status:	Exploration
Royalty Ownership:	State of Alaska/Federal
Operator:	ConocoPhillips Alaska, Inc.
Acres:	23,369
Working Interest:	ConocoPhillips Alaska, Inc. 57%
	Anadarko Petroleum Corporation 20%
	Forest Oil Corporation 14%
	Devon Energy Production Company 4%
	ExxonMobil 4%
	Others 1%

Starichkof Discovery

Status:	Exploration
Discovery:	1967, Penzoil Starichkof St. #1
Reservoir:	Tertiary Hemlock Conglomerate

Cook Inlet

North Fork Unit

Status:	Shut-In
Royalty Ownership:	State of Alaska/Federal
Operator:	Gas-Pro Alaska, LLC
Acres:	2,480
First Production:	Shut-in in 1965

North Fork PA

Status:	Suspended
Discovery:	1965, Chevron North Fork Unit #41-35
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Gas-Pro Alaska, LLC 73%
	ConocoPhillips Alaska, Inc. 27%

Non-Unitized Production

Middle Ground Shoal Field

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Cross Timbers Oil Co./ Forest Oil Company/ Unocal
First Production:	1967
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations

Granite Point Field

Status:	Producing Oil and Gas
Royalty Ownership:	State of Alaska
Operator:	Unocal
First Production:	1967
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock and Tyonek formations

Cook Inlet Platform
B. Webb

Table 3.2 Fields and Pools

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
ALBERT KALOA	GAS		1/4/1968	CIRI	shut-in 1971	CI, west side, onshore
ALPINE	OIL	Colville River	3/27/1994	ConocoPhillips	prod. began 2000, Nov.	NS, Colville Delta, onshore
AURORA	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2000	NS, central, onshore
BADAMI	OIL & GAS	Badami	4/27/1990	BP	prod. began 1998, Aug. shut in	NS, Canning R., onshore
BEAVER CREEK	OIL & GAS	Beaver Creek	12/17/1972	UNOCAL	prod. began 1973	CI, east side, onshore
BELUGA RIVER	GAS	Beluga River	12/1/1962	ConocoPhillips	prod. began 1968	CI, west side, onshore
BIRCH HILL	GAS	Birch Hill	6/9/1965	ConocoPhillips	shut-in 1965	CI, east side, onshore
BOREALIS	OIL	Prudhoe Bay	8/8/1969	BP	prod. began 2000	NS, central, onshore
BURGER	OIL & GAS		10/14/1989		undeveloped	OCS, Chukchi Sea, offshore
CANNERY LOOP	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP BELUGA	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP STERLING	GAS	Cannery Loop	10/23/2000	Marathon	prod. began 2000	CI, east side, onshore
CASCADE	OIL	Milne Point	3/14/1993	BP	prod. began 1996, Aug.	NS, central, onshore
COLVILLE DELTA	OIL		4/26/1985	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
EAST BARROW	GAS	Barrow	5/4/1974	NS Borough	prod. began 1981	NS, western, onshore
EAST KURUPA	GAS		3/1/1976		undeveloped	NS, foothills, onshore
EAST UMIAT	GAS		3/28/1964	UMC Petroleum	shut-in, no production.	NS, foothills, onshore
EIDER	OIL	Duck Island	3/20/1998	BP	prod. began 1998, Jul.	NS, central, onshore
ENDICOTT	OIL	Duck Island	2/14/1978	BP	prod. began 1987	NS, central, onshore
FALLS CREEK	GAS	Falls Creek	4/10/1961	Marathon	shut-in 1961; prod began 2003	CI, east side, onshore
FIORD	OIL	Colville River	4/18/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
FISH CREEK	OIL		9/4/1949	ConocoPhillips	undeveloped	NS, NPRA, onshore
FLAXMAN	OIL	Point Thomson	9/6/1975	Exxon	undeveloped	NS, Canning R., offshore
GRANITE POINT	OIL & GAS		5/16/1965	UNOCAL	prod. began 1967	CI, west side, offshore
GRANITE POINT TYONEK	GAS		8/5/1965	UNOCAL	prod. began 1995	CI, west side, offshore
GRASSIM OSKOLKOFF	GAS	Ninilchik	7/31/2001	Marathon	prod began 2003	CI, east side, offshore
GUBIK	GAS		8/11/1951		undeveloped	NS, foothills, onshore
GWYDYR BAY	OIL	Prudhoe Bay	11/25/1969	BP	undeveloped	NS, central, onshore
HAMMERHEAD	OIL		10/11/1986	Anadarko	undeveloped	OCS, Beaufort Sea, offshore
HAPPY VALLEY	GAS	Deep Creek	7/9/2003	Unocal	prod began 2004	CI, east side, onshore
HEMI SPRINGS	OIL		4/3/1984		undeveloped	NS, central, onshore
IVAN RIVER	GAS	Ivan River	10/8/1966	UNOCAL	prod. began 1990	CI, west side, onshore
KALUBIK	OIL	Alpine	5/1/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
KASILOF	GAS	Kasilof	2004	Marathon	undeveloped	CI, east side, offshore
KATALLA	OIL		1/1/1902		abandoned 1933	Gulf of Alaska, onshore
KAVIK	GAS		11/5/1969	Phillips	undeveloped	NS, foothills, onshore
KEMIK	GAS		6/17/1972	BP	undeveloped	NS, foothills, onshore
KENAI	GAS	Kenai	10/11/1959	Marathon	prod. began 1961	CI, east side, onshore
KENAI STERLING	GAS	Kenai		Marathon		CI, east side, onshore
KUPARUK RIVER	OIL & GAS	Kuparuk River	4/7/1969	ConocoPhillips	prod. began 1981	NS, central, onshore
KUVLUM	OIL		10/1/1992	Union Texas Pet.	undeveloped	OCS, Beaufort Sea, offshore
LEWIS RIVER	GAS	Lewis River	10/1/1975	UNOCAL	prod. began 1984	CI, west side, onshore
LIBERTY	OIL		3/3/1983	BP	undeveloped	OCS, Beaufort Sea, offshore
LISBURNE	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1986	NS, central, onshore
LONE CREEK	GAS	Moquawkie	10/12/1998	Anadarko	prod began 2003	CI, west side, onshore
MCARTHUR RIVER	OIL & GAS	Trading Bay	9/29/1965	UNOCAL	prod. began 1967	CI, west side, offshore
MCARTHUR RIVER TYONEK	GAS	Trading Bay		UNOCAL		CI, west side, offshore
MEADE	GAS		8/21/1950		undeveloped	NS, NPRA, onshore
MELTWATER	OIL	Kuparuk River	4/26/2000	ConocoPhillips	prod. began 2001, Nov.	NS, central, onshore
MIDDLE GROUND SHOAL	OIL	N & S MGS	6/10/1962	UNOCAL/XTO	prod. began 1967	CI, mid channel, offshore
MIDNIGHT SUN	OIL	Prudhoe Bay	12/20/1997	BP	prod. began 1998, Oct.	NS, central, onshore
MIKKELSON	OIL		11/11/1978	ExxonMobil	undeveloped	NS, central, onshore
MILNE POINT	OIL	Milne Point	8/9/1969	BP	prod. began 1985	NS, central, onshore
MOQUAWKIE	GAS	Moquawkie	11/28/1965	CIRI	shut-in 1979	CIt, west side, onshore
NIKAITCHUQ	OIL	Nikaitchuq	4/1/2004	Kerr-McGee	undeveloped	NS, central, offshore
N MID GROUND SH (MGS)	GAS	N Mid Ground Sh	6/10/1962	UNOCAL	prod. began 1982	CI, mid channel, offshore
N MIDDLE GROUND SHOAL	GAS		11/15/1964	UNOCAL/Cross Timbe	undeveloped	CI, mid channel, offshore
NANUQ	OIL	Colville River	5/7/2000	ConocoPhillips	prod. began 2000	NS, Colville Delta, onshore
NIAKUK	OIL	Prudhoe Bay	3/7/1985	BP	prod. began 1994	NS, central, offshore
NICOLAI CREEK	GAS	Nicolai Creek	4/28/1966	Aurora Gas LLC	production began 2001	CI, west side, onshore
NORTH COOK INLET	GAS	N Cook Inlet	8/21/1962	ConocoPhillips	prod. began 1970	CI, mid channel, offshore
NORTH FORK	GAS	North Fork	12/20/1965	Alliance LLC	shut-in 1965	CI, east side, onshore
NORTH PRUDHOE	OIL & GAS	Prudhoe Bay	3/31/1970	BP	prod. began 1993, Oct.	NS, central, onshore
NORTHSTAR	OIL & GAS	Northstar	1/30/1984	BP	prod. began 2001, Oct.	NS, central, offshore
NPRA LOOKOUT	OIL/COND		4/30/2002	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA RENDEZVOUS	OIL/COND		4/27/2001	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA SPARK	OIL/COND		4/12/2000	ConocoPhillips	undeveloped	NS, NPRA, onshore

Table 3.2 Fields and Pools, Cont.

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
OOOGURUK	OIL	Oooguruk	3/29/2003	Pioneer	undeveloped	NS, central, offshore
PALM	OIL	Kuparuk River	2/21/2001	ConocoPhillips	prod began 2002	NS, central, onshore
PETE'S WICKED	OIL	Prudhoe Bay	2/24/1997	BP	undeveloped	NSe, central, onshore
POINT MCINTYRE	OIL & GAS	Prudhoe Bay	3/22/1988	BP	prod. began 1993	NS, central, offshore
POINT THOMSON	OIL & GAS	Point Thomson	12/8/1977	ExxonMobil	undeveloped	NS, Canning R., onshore
POLARIS	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2001	NS, central, onshore
PRETTY CREEK	GAS	Pretty Creek	2/20/1979	UNOCAL	prod. began 1986	CI, west side, onshore
PRUDHOE BAY	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1977	NS, central, onshore
REDOUBT SHOAL	OIL	Redoubt Shoal	9/21/1968	Forest	prod. began 2001	CI, west side, offshore
SAG DELTA NORTH	OIL	Duck Island	1/25/1982	BP	prod. began 1989	NS, central, onshore
SAG RIVER	OIL	Milne Point	8/9/1969	BP	prod. began 1994	NSe, central, onshore
SAMBUCCA	OIL	Prudhoe Bay	1/20/1998	BP		NS, central, onshore
SANDPIPER	OIL	Sandpiper	1/25/1986	Murphy	undeveloped	OCS, Beaufort Sea, offshore
SCHRADER BLUFF	OIL	Milne Point	8/9/1969	BP	prod. began 1991	NS, central, onshore
SIKULIK	GAS		4/18/1988	NS Borough	undeveloped	NS, western, onshore
SIMPSON	OIL		10/23/1950		undeveloped	NS, NPRA, onshore
SOURDOUGH	OIL	Point Thomson	4/27/1994	BP	undeveloped	NS, Canning R., onshore
SOUTH BARROW	GAS	Barrow	4/15/1949	NS Borough	prod. began 1950	NS, western, onshore
SQUARE LAKE	GAS		4/18/1952		undeveloped	NS, NPRA, onshore
STARICHKOF	OIL	Cosmopolitan	4/1/1967	ConocoPhillips Alaska	undeveloped	CI, east side, offshore
STERLING	GAS	Sterling	7/11/1961	Marathon	prod. began 1962	CI, east side, onshore
STERLING BELUGA	GAS	Sterling	1/19/1999	Marathon	prod. began 1999	CI, east side, onshore
STERLING TYONEK	GAS	Sterling	1/19/1999	Marathon		CI, east side, onshore
STINSON	confidential		8/20/1990	ConocoPhillips	undeveloped	NS, Canning R., offshore
STUMP LAKE	GAS	Stump Lake	5/14/1978	UNOCAL	prod. began 1990	CI, west side, onshore
SUSAN DIONNE	GAS	Ninilchik	1/23/2002	Marathon	prod began 2003	CI, east side, offshore
SWANSON RIVER	OIL & GAS	Swanson River	7/19/1957	UNOCAL	prod. began 1958	CI, east side, onshore
TABASCO	OIL	Kuparuk River	10/18/1986	ConocoPhillips	prod. began 1998, May	NS, central, onshore
TARN	OIL	Kuparuk River	2/2/1991	ConocoPhillips	prod. began 1998, Aug.	NS, central, onshore
THETIS ISLAND	OIL		4/28/1993	Anadarko	undeveloped	NS, central, offshore
TRADING BAY	OIL	N Trading Bay	6/17/1965	UNOCAL	prod. began 1967	CI, west side, offshore
TRADING BAY TYONEK	GAS	N Trading Bay		UNOCAL		CI, west side, offshore
TYONEK DEEP	OIL	N Cook Inlet	11/5/1991	ConocoPhillips	undeveloped	CI, mid channel, offshore
UGNU	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod began 2003	NS, central, onshore
UMIAT	OIL		12/26/1946	U.S. Dept Interior	undeveloped	NS, foothills, onshore
WALAKPA	GAS		2/7/1980	NS Borough	prod. began 1992	NS, western, onshore
WEST BEACH	OIL & GAS	Prudhoe Bay	7/22/1976	BP	prod. began 1994, Apr.	NS, central, onshore
WEST FORELAND	GAS		3/29/1962	ConocoPhillips	shut-in 1962; prod began 2001	CI, west side, onshore
WEST FORK	GAS		9/26/1960	CIRI	prod. began 1978	CI, east side, onshore
WEST MCARTHUR RIVER	OIL & GAS	W Mcarthur River	12/2/1991	Forest	prod. began 1994	CI, west side, onshore
WEST SAK	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod. began 1998	NS, central, onshore
WOLF CREEK	GAS		6/4/1951		undeveloped	NS, NPRA, onshore
WOLF LAKE	GAS		11/12/1983	Maratthon	prod. began 2001	CI east side, onshore

Section Four

Historic and Forecast Production

Introduction

This section enumerates historic and projected oil and gas production for all North Slope and Cook Inlet producing areas; unit participating areas, and lease pools.

Forecast production volumes are based on original oil and gas in-place estimates and recovery factor. Original in-place means total volume of oil and gas in-place in a three-dimensional reservoir container, regardless of recoverability. Recoverable means the physical limitations of the reservoir and limits of existing technology, and considering economic factors, like price, volume, and rate of return on capital. Original and recoverable estimates are revised with new data and information on recovery and characteristics of the reservoir. Revised estimates are used to calculate remaining reserves.

Remaining Reserves are oil or gas that are economic and technologically feasible to produce and are expected to produce revenue in the foreseeable future. Total North Slope reserves are the sum of forecasted production from year end 2003 to 2035 based on year-end 2003 reporting. Most Remaining Reserves of oil and gas generate royalty and other revenue to the State.

Historic and Forecast Production is summarized by producing area or unit as follows:

	Producing Region	Hydrocarbon Type	Table or Figure
Reserves	North Slope	Oil/Gas	Table IV.1
	Cook Inlet	Oil/Gas	Table IV.2
Historic	North Slope	Oil	Table IV.3
	Incremental Production	Oil	Figures IV.1A & B
	Cook Inlet	Oil	Table IV.4
	North Slope	Gas	Table IV.5 and Figure IV.2
	Cook Inlet	Gas	Table IV.6
	Cook Inlet	Gas	Table IV.10 and Figure IV.7
Forecast	North Slope	Oil	Table IV.7 and Figures IV.3A & B
	Cook Inlet	Oil	Table IV.8 and Figure IV.4
	North Slope	Gas	Figure IV.5
	Cook Inlet	Gas	Table IV.9 and Figures IV.6

Historic information is based on data from the Alaska Oil and Gas Conservation Commission (AOGCC) and the Division of Oil and Gas (DOG) Royalty Accounting Section. The forecast of North Slope oil production is based primarily on estimates prepared by the Alaska Department of Revenue. Forecast oil and gas production in Cook Inlet is based DOG assumptions about future rates of production decline on a field-by-field basis. Similarly, the forecast of gas production in the North Slope is based on DOG methods and assumptions. These are enumerated in footnotes. Detailed estimation assumptions are available from DOG on request.

North Slope

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit[2]	-	0	14.6%	-	-
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	454	-	10.0%	45	-
CRU Satellite	110	-	12.5%	14	-
TOTAL CRU	564	400		59	60
Duck Island Unit	132	843	12.5-14.4%	16	121
Kuparuk River Unit					
Kuparuk	960	1,000	12.5%	120	125
West Sak[3]	530	100	12.5%	66	13
Tabasco	15	-	12.5%	2	-
Tarn	72	50	12.5%	9	6
Meltwater	39	-	12.5%	5	
Other Kuparuk Satellite	-		12.5%	-	-
TOTAL KRU	1,617	1,150		202	144
Milne Point Unit[3]	481	14	14.6%	70	2
North Star	154	450	16.0%	25	72
Prudhoe Bay Unit					
Initial Participating Areas					
Prudhoe IPAs[4]	2,851	-	12.5%	356	-
PBU Satellites[5]	475	-	12.5%	59	-
TOTAL PBU IPA	3,325	23,000	12.5%	416	2,875
Greater Point McIntyre Area					
Lisburne	42	1,000	12.5%	5	125
Niakuk	42	26	12.5%	5	3
North Prudhoe Bay State	-	-	12.5%	-	-
Pt. McIntyre	212	500	13.8%	29	69
West Beach	-	-	12.5%	-	-
TOTAL GPMA	296	1,526		40	197
TOTAL PBU	3,621	24,526		455	3,072
Point Thomson	329	8,000	12.5-16.0%	41	1,000
Other Undeveloped[6]	419	-	6%[7]	25	-
TOTAL North Slope (State Lands)	7,316	35,417		853	3,471
NPRA	254				
TOTAL North Slope Alaska	7,570	35,417	-	853	3,471

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2003 through 2035.

[2] The Badami field was put in warm shut-in in August, 2003; production may resume in 2005.
MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[3] Based on a aggressive heavy oil component.

[4] Oil Rim and Gas Cap.

[5] Includes Midnight Sun, Aurora, Borealis, Orion and Polaris.

[6] Includes Liberty and other known on- and off-shore accumulations.

7 Estimated combined rate for State and Federal on- and off-shore accumulations.

Cook Inlet

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Beaver Creek	0.2	75.0	-	-	-
Beluga River	-	422.6	12.5%	-	52.8
Cannery Loop	-	21.0	12.6%	-	2.6
Deep Creek		30.0	12.5 - 18%		
Ninilchik[2]		100.0	5 - 12.5%	-	12.5
Granite Point	8.7	9.6	12.5%	1.1	1.2
Ivan River, Lewis River, Pretty Creek, Stump Lake	-	15.0	14.3 - 17.7%	-	2.1
Kenai	-	181.6	12.5%	-	22.7
Lone Creek[3]	-	5.0	-	-	-
McArthur River	24.1	168.3	12.5%	3.0	21.0
Middle Ground Shoal	7.9	3.7	12.5%	1.0	0.5
Nicolai Creek	-	1.0	5 - 12.5%	-	0.1
North Cook Inlet	-	596.7	12.5%	-	74.6
North Trading Bay[3]	-	10.0	12.5%	-	1.3
Redoubt	5.0	6.0	5 - 12.5%		-
Sterling	-	22.0	12.5%	-	2.8
Swanson River	2.4	9.6	-	-	-
Trading Bay	2.9	23.0	12.5%	0.4	2.9
West Foreland[3]	-	10.0	9.4%	-	0.9
West Fork	-	3.0	-	-	-
West MacArthur River	3.9	0.4	12.5%	0.5	0.1
Wolf Lake[4]	-	42.0	-	-	-
					-
Undeveloped					-
Birch Hill	-	-	-	-	-
North Fork	-	2.0	12.5%	-	0.3
Tyonek Deep	25.0	30.0	12.5%	3.1	3.8
Other Proven/ Undeveloped[5]		300.0	12.5%		37.5
TOTAL COOK INLET	80.0	2,087.5		9.1	239.6

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2003 through 2035. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] Ninilchik Unit includes Falls Creek, Grassim Oskolkoff, and Susan Dionne PAs.

[3] Lone Creek, Nicolai Creek, North Trading Bay are point estimates. West Foreland royalty is 5% on State acreage and 12.5% on Federal acreage.

[4] Subsurface lands owned by Cook Inlet Region, Incorporated.

[5] Includes Kasilof and Nikolaevsk units and other exploration areas on the Kenai Peninsula and West side of Cook Inlet.

North Slope (Millions of Barrels per Year)

	Badami	Colville River			Northstar	Duck Island									
		Alpine	Nanuk	TOTAL Colville River		Eider[1]	Endicott				Sag Delta North[1]			Ivishak[1]	TOTAL Duck Island Unit
	oil	oil	oil		oil	oil	oil	ngl	inj	net	oil	ngl	net	oil	
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1986	-	-	-	-	-	-	0.011	-	0.007	0.004	-	-	-	-	0.004
1987	-	-	-	-	-	-	8.796	0.003	0.014	8.785	-	-	-	-	8.785
1988	-	-	-	-	-	-	37.441	0.492	-	37.933	-	-	-	-	37.933
1989	-	-	-	-	-	-	35.746	0.839	-	36.585	0.349	0.005	0.354	-	36.939
1990	-	-	-	-	-	-	36.181	0.845	-	37.026	1.542	0.028	1.570	-	38.596
1991	-	-	-	-	-	-	38.996	1.170	-	40.165	2.309	0.048	2.357	-	42.522
1992	-	-	-	-	-	-	40.603	1.468	-	42.071	1.002	0.011	1.013	-	43.084
1993	-	-	-	-	-	-	38.433	1.551	-	39.984	0.761	0.007	0.768	-	40.752
1994	-	-	-	-	-	-	33.916	1.481	-	35.397	0.368	0.003	0.371	-	35.768
1995	-	-	-	-	-	-	32.998	1.203	-	34.201	0.235	0.001	0.236	-	34.437
1996	-	-	-	-	-	-	26.450	1.013	-	27.463	0.199	0.001	0.200	-	27.663
1997	-	-	-	-	-	-	21.121	1.550	-	22.671	0.255	0.002	0.257	-	22.928
1998	0.731	-	-	-	-	0.395	16.775	1.265	-	18.040	0.193	0.001	0.194	-	18.629
1999	1.150	-	-	-	-	0.605	13.529	1.371	-	14.900	-	-	-	0.179	15.684
2000	0.930	2.231	-	2.231	-	0.248	11.622	1.436	-	13.058	-	-	-	0.148	13.454
2001	0.675	28.688	0.019	28.707	1.266	0.660	9.637	1.324	-	10.961	-	-	-	0.142	11.763
2002	0.579	35.041	-	35.041	17.903	0.422	8.509	1.202	-	9.711	-	-	-	0.145	10.279
2003	0.282	35.582	-	35.582	22.968	0.242	9.104	1.189	-	10.293	-	-	-	0.092	10.627
TOTAL	4.347	101.542	0.019	101.562	42.136	2.572	419.868	19.403	0.021	439.249	7.213	0.107	7.320	0.706	449.847

Notes:

[1]AOGCC combined 1999 production volumes for Eider and Sag Delta North and reported these data in the "Ivishak Pool."

North Slope (Millions of Barrels per Year)

	Prudhoe Bay Unit Initial Participating Areas (IPAs) and Satellites									
	Prudhoe Bay[2]				Midnight Sun	Polaris (Schrader Bluff)	Aurora	Borealis	Orion	TOTAL PBU IPAs + Satellites
	oil	ngl	inj	net	oil	oil	oil	oil	oil	
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-
1969	0.277	-	0.217	0.060	-	-	-	-	-	0.060
1970	1.193	-	0.879	0.314	-	-	-	-	-	0.314
1971	1.157	-	0.833	0.324	-	-	-	-	-	0.324
1972	0.922	-	0.792	0.130	-	-	-	-	-	0.130
1973	0.944	-	0.817	0.127	-	-	-	-	-	0.127
1974	2.170	-	1.640	0.530	-	-	-	-	-	0.530
1975	2.870	-	2.147	0.723	-	-	-	-	-	0.723
1976	4.604	-	3.611	0.993	-	-	-	-	-	0.993
1977	115.258	-	2.075	113.183	-	-	-	-	-	113.183
1978	397.679	-	-	397.679	-	-	-	-	-	397.679
1979	468.412	-	-	468.412	-	-	-	-	-	468.412
1980	555.394	0.254	-	555.648	-	-	-	-	-	555.648
1981	555.170	0.450	-	555.620	-	-	-	-	-	555.620
1982	558.889	0.500	-	559.389	-	-	-	-	-	559.389
1983	560.837	0.311	-	561.148	-	-	-	-	-	561.148
1984	561.952	0.317	-	562.269	-	-	-	-	-	562.269
1985	568.534	0.056	-	568.590	-	-	-	-	-	568.590
1986	561.538	0.230	-	561.768	-	-	-	-	-	561.768
1987	572.045	14.610	-	586.655	-	-	-	-	-	586.655
1988	559.412	19.274	-	578.686	-	-	-	-	-	578.686
1989	505.940	16.928	-	522.868	-	-	-	-	-	522.868
1990	470.140	16.094	-	486.234	-	-	-	-	-	486.234
1991	465.399	21.307	-	486.706	-	-	-	-	-	486.706
1992	432.587	23.902	-	456.489	-	-	-	-	-	456.489
1993	385.811	23.879	-	409.690	-	-	-	-	-	409.690
1994	351.493	22.825	-	374.318	-	-	-	-	-	374.318
1995	313.629	26.810	-	340.439	-	-	-	-	-	340.439
1996	282.060	30.549	-	312.609	-	-	-	-	-	312.609
1997	252.421	31.580	-	284.001	-	-	-	-	-	284.001
1998	221.781	30.983	-	252.764	0.061	-	-	-	-	252.825
1999	194.338	29.423	-	223.761	1.696	0.027	-	-		225.484
2000	187.056	30.145	-	217.200	1.441	0.414	0.261	-	-	219.317
2001	166.718	27.526	-	194.244	1.305	0.419	1.738	1.346	-	199.052
2002	150.975	26.640	-	177.615	3.157	0.766	2.397	8.439	0.097	192.471
2003	141.302	24.972	-	166.274	1.719	0.918	3.782	11.791	0.368	184.852
TOTAL	10,429.605	394.592	13.011	10,811.186	7.661	1.626	4.396	9.784	0.097	10,834.751

Notes:

[2]Production for the Prudhoe Bay IPAs includes oil and condensates.

North Slope (Millions of Barrels per Year)

	Greater Point McIntyre Area (GPMA)																TOTAL Prudhoe Bay Unit (IPA+GPMA)
	Lisburne			Niakuk[3]			North Prudhoe Bay			Point McIntyre			West Beach			TOTAL GPMA	
	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.060
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.314
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	555.648
1981	0.002	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	0.002	555.622
1982	0.208	-	0.208	-	-	-	-	-	-	-	-	-	-	-	-	0.208	559.597
1983	0.087	-	0.087	-	-	-	-	-	-	-	-	-	-	-	-	0.087	561.235
1984	0.294	-	0.294	-	-	-	-	-	-	-	-	-	-	-	-	0.294	562.563
1985	1.123	-	1.123	-	-	-	-	-	-	-	-	-	-	-	-	1.123	569.713
1986	3.594	-	3.594	-	-	-	-	-	-	-	-	-	-	-	-	3.594	565.362
1987	16.199	0.458	16.657	-	-	-	-	-	-	-	-	-	-	-	-	16.657	603.312
1988	15.095	1.008	16.103	-	-	-	-	-	-	-	-	-	-	-	-	16.103	594.789
1989	13.737	1.093	14.830	-	-	-	-	-	-	-	-	-	-	-	-	14.830	537.698
1990	14.669	1.204	15.873	-	-	-	-	-	-	-	-	-	-	-	-	15.873	502.107
1991	13.316	1.337	14.653	-	-	-	-	-	-	-	-	-	-	-	-	14.653	501.359
1992	12.517	1.464	13.981	-	-	-	-	-	-	-	-	-	-	-	-	13.981	470.470
1993	8.473	1.277	9.750	-	-	-	0.418	0.015	0.433	7.543	0.090	7.633	0.724	0.009	0.733	18.549	428.239
1994	6.846	0.939	7.785	3.383	0.028	3.411	0.727	0.031	0.758	37.684	0.548	38.232	0.512	0.012	0.524	50.710	425.028
1995	5.454	0.823	6.277	7.004	0.077	7.081	0.702	0.034	0.736	50.225	0.679	50.904	0.163	0.005	0.168	65.166	405.605
1996	4.465	0.674	5.139	10.937	0.108	11.045	0.126	0.003	0.129	57.926	0.825	58.751	0.474	0.025	0.499	75.563	388.172
1997	3.002	0.416	3.418	10.265	0.136	10.401	-	-	-	58.498	1.042	59.540	0.319	0.027	0.346	73.705	357.706
1998	2.468	0.331	2.799	10.356	0.128	10.484	0.001	0.001	0.002	47.553	1.009	48.562	0.096	0.006	0.102	61.949	314.774
1999	2.203	0.326	2.529	9.857	0.131	9.988	0.008	0.001	0.009	33.460	0.831	34.291	0.603	0.067	0.670	47.486	272.970
2000	3.203	0.601	3.804	7.336	0.101	7.437	0.003	0.001	0.003	23.737	0.675	24.413	0.401	0.053	0.454	36.111	255.428
2001	3.054	0.622	3.675	6.978	0.109	7.087	-	-	-	18.094	0.600	18.693	0.110	0.014	0.125	29.580	228.632
2002	3.065	0.484	3.549	5.814	0.055	5.868	-	-	-	14.744	0.472	15.216	0.004	0.000	0.004	24.638	217.109
2003	3.335	0.480	3.816	4.599	0.039	4.638	-	-	-	13.320	0.518	13.838	0.010	0.001	0.011	22.302	207.154
TOTAL	136.409	13.538	149.946	76.529	0.911	77.440	1.984	0.085	2.070	362.784	7.288	370.072	3.416	0.220	3.635	603.164	11,622.767

Notes:

[3]Niakuk production volumes for 1994-1998 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

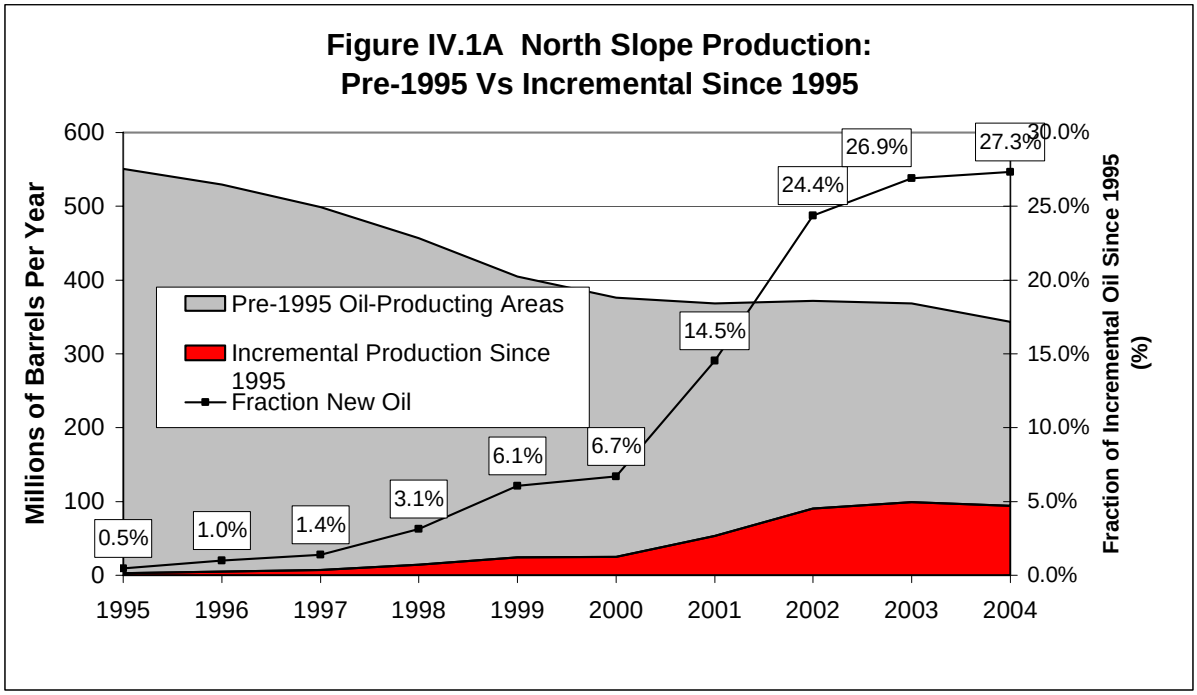
North Slope (Millions of Barrels per Year)

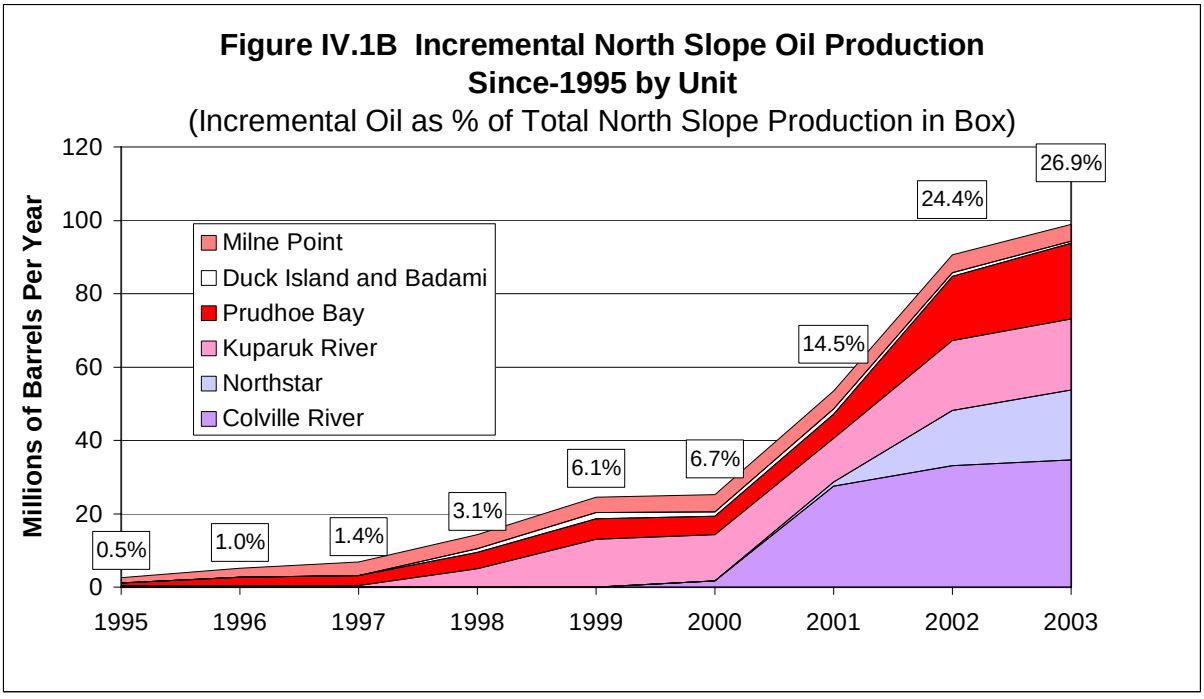
NORTH SLOPE

	Kuparuk River Unit								Milne Point Unit				TOTAL OIL	TOTAL NGL	TOTAL INJECT-ED	TOTAL NET
	Kuparuk			Tabasco	Tarn	West Sak	Melt-water	TOTAL Kuparuk River Unit	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit				
	oil	ngl	net	oil	oil	oil	oil		oil	oil	oil					
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	0.277	-	0.217	0.060
1970	0.006	-	0.006	-	-	-	-	0.006	-	-	-	-	1.199	-	0.879	0.320
1971	-	-	-	-	-	-	-	-	-	-	-	-	1.157	-	0.833	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	0.922	-	0.792	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	0.944	-	0.817	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	2.170	-	1.640	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	2.870	-	2.147	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	4.604	-	3.611	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	115.258	-	2.075	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	397.679	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	468.412	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	555.394	0.254	-	555.648
1981	1.092	-	1.092	-	-	-	-	1.092	-	-	-	-	556.264	0.450	-	556.714
1982	32.406	-	32.406	-	-	-	-	32.406	-	-	-	-	591.503	0.500	-	592.003
1983	39.876	-	39.876	-	-	0.006	-	39.882	-	-	-	-	600.806	0.311	-	601.117
1984	46.084	-	46.084	-	-	0.124	-	46.208	-	-	-	-	608.454	0.317	-	608.771
1985	78.926	0.761	79.687	-	-	0.326	-	80.013	0.704	-	-	0.704	649.613	0.817	-	650.430
1986	93.900	1.072	94.972	-	-	0.300	-	95.272	4.709	-	-	4.709	664.052	1.302	0.007	665.347
1987	102.448	1.257	103.705	-	-	-	-	103.705	0.040	-	-	0.040	699.528	16.328	0.014	715.842
1988	110.891	0.256	111.147	-	-	-	-	111.147	-	-	-	-	722.839	21.030	-	743.869
1989	109.770	-	109.770	-	-	-	-	109.770	3.715	-	-	3.715	669.257	18.865	-	688.122
1990	107.206	-	107.206	-	-	-	-	107.206	6.624	-	0.004	6.628	636.366	18.171	-	654.537
1991	113.571	-	113.571	-	-	-	-	113.571	6.701	-	0.756	7.457	641.048	23.862	-	664.910
1992	118.506	-	118.506	-	-	-	-	118.506	5.812	-	1.135	6.947	612.162	26.845	-	639.007
1993	115.166	-	115.166	-	-	-	-	115.166	5.704	-	1.060	6.764	564.093	26.828	-	590.921
1994	111.795	-	111.795	-	-	-	-	111.795	5.648	-	1.030	6.678	553.402	25.867	-	579.269
1995	106.999	-	106.999	-	-	-	-	106.999	7.352	0.173	1.167	8.692	526.101	29.632	-	555.733
1996	99.459	-	99.459	-	-	-	-	99.459	12.665	0.346	1.090	14.101	496.197	33.198	-	529.395
1997	95.970	-	95.970	-	-	0.001	-	95.971	17.055	0.363	1.536	18.954	460.806	34.753	-	495.559
1998	91.702	-	91.702	0.483	3.534	0.562	-	96.281	18.314	0.162	1.943	20.419	417.110	33.724	-	450.834
1999	82.394	-	82.394	1.920	9.541	1.190	-	95.045	17.488	0.018	2.178	19.684	372.383	32.150	-	404.533
2000	74.133	-	74.133	1.911	8.767	1.520	-	86.330	16.572	-	2.498	19.069	344.431	33.012	-	377.443
2001	68.265	-	68.265	1.318	8.052	1.998	0.149	79.782	15.273	0.248	3.818	19.339	339.969	30.194	-	370.163
2002	58.903	-	58.903	1.089	12.011	2.472	2.902	77.378	13.314	0.130	5.219	18.663	348.098	28.853	-	376.951
2003	58.536	-	58.536	1.542	12.343	2.857	2.125	77.402	11.604	0.101	7.001	18.707	345.527	27.199	-	372.726
TOTAL	1,918.004	3.346	1,921.350	8.262	54.248	11.356	5.176	2,000.392	169.294	1.541	30.434	201.270	13,970.895	464.462	13.032	14,422.325

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by FIeld and Pool" (Monthly Reports).

North Slope (Millions of Barrels per Year)





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Cook Inlet (Millions of Barrels per Year)

	Beaver Creek	Cannery Loop[1]	Granite Point[2]	Kenai[1]	McArthur River[3]			Middle Ground Shoal[4]	North Trading Bay Unit	Redoubt Shoal
	oil	ngl	oil	ngl	oil	ngl	net	oil	oil	oil
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	0.002	-	0.001	-	0.001	0.027	-	-
1966	-	-	-	-	0.003	-	0.003	2.649	-	-
1967	-	-	7.052	-	0.749	-	0.749	7.404	0.002	-
1968	-	-	13.131	-	21.782	-	21.782	14.134	0.185	0.002
1969	-	-	9.183	0.002	31.301	-	31.301	10.467	4.310	-
1970	-	-	7.522	0.002	40.165	0.426	40.591	12.719	3.265	-
1971	-	-	5.577	0.001	40.537	0.593	41.130	11.304	2.029	-
1972	0.002	-	4.663	0.002	40.774	0.570	41.344	9.719	2.553	-
1973	0.416	-	4.767	0.001	38.884	0.661	39.545	10.239	2.022	-
1974	0.375	-	4.237	-	39.145	0.654	39.799	9.001	2.127	-
1975	0.322	-	4.361	0.001	40.876	0.644	41.520	8.670	1.530	-
1976	0.302	-	4.471	0.001	35.810	0.653	36.463	8.864	1.096	-
1977	0.276	-	4.711	-	33.235	0.733	33.968	7.617	0.970	-
1978	0.223	-	4.867	0.001	30.223	0.730	30.953	6.382	0.797	-
1979	0.211	-	4.613	-	25.440	0.541	25.981	5.545	0.609	-
1980	0.214	-	4.394	-	20.894	0.412	21.306	4.854	0.372	-
1981	0.180	-	3.975	-	18.022	0.484	18.506	4.291	0.235	-
1982	0.182	-	3.467	-	15.806	0.449	16.255	3.573	0.132	-
1983	0.170	-	3.550	-	13.564	0.332	13.896	3.381	0.117	-
1984	0.159	-	3.287	-	11.707	0.317	12.024	3.238	0.080	-
1985	0.146	-	3.052	-	7.454	0.194	7.648	3.098	0.113	-
1986	0.158	-	3.169	-	7.942	0.228	8.170	3.211	0.220	-
1987	0.185	-	2.803	-	7.375	0.196	7.571	2.834	0.246	-
1988	0.141	-	2.677	-	7.143	0.162	7.305	2.742	0.195	-
1989	0.227	-	2.275	-	6.955	-	6.955	2.769	0.179	-
1990	0.212	-	1.462	-	4.265	-	4.265	2.688	0.121	-
1991	0.179	-	2.064	-	7.247	-	7.247	2.670	0.168	-
1992	0.175	-	2.522	-	7.397	-	7.397	2.423	0.030	-
1993	0.153	-	2.488	-	6.636	-	6.636	2.160	-	-
1994	0.140	<.001	2.209	-	7.091	-	7.091	2.785	-	-
1995	0.132	<.001	2.580	-	6.622	-	6.622	2.823	-	-
1996	0.125	<.001	2.556	-	6.102	-	6.102	2.396	-	-
1997	0.119	-	2.432	-	5.059	-	5.059	2.223	-	-
1998	0.103	-	2.079	-	4.817	-	4.817	2.156	-	-
1999	0.100	-	1.787	-	4.697	-	4.697	1.968	-	-
2000	0.092	-	1.742	-	4.822	-	4.822	1.894	-	0.002
2001	0.085	-	1.620	-	5.353	-	5.353	2.032	-	0.001
2002	0.079	-	1.527	-	5.510	-	5.510	1.959	-	0.046
2003	0.076	-	1.440	-	4.323	-	4.323	1.497	-	0.911
TOTAL	5.659	-	140.315	0.011	615.728	8.979	624.707	190.407	23.703	0.962

Notes:

[1]These gas fields temporarily produced NGLs.

[2]Includes Middle Kenai and Undefined Hemlock pools.

[3]Includes Hemlock, Middle Kenai G, and West Foreland Pools.

[4]Includes A, B, C, D, E, F, and G pools

Cook Inlet (Millions of Barrels per Year)

	Swanson River[5]			Trading Bay[6]			West McArthur River	TOTAL OIL	TOTAL NGL	TOTAL
	oil	ngl	net	oil	ngl	net	oil			
1958	0.036	-	0.036	-	-	-	-	0.036	-	0.036
1959	0.187	-	0.187	-	-	-	-	0.187	-	0.187
1960	0.558	-	0.558	-	-	-	-	0.558	-	0.558
1961	6.327	-	6.327	-	-	-	-	6.327	-	6.327
1962	10.259	-	10.259	-	-	-	-	10.259	-	10.259
1963	10.740	-	10.740	-	-	-	-	10.740	-	10.740
1964	11.054	-	11.054	-	-	-	-	11.054	-	11.054
1965	11.099	-	11.099	0.002	-	0.002	-	11.131	-	11.131
1966	11.712	-	11.712	-	-	-	-	14.364	-	14.364
1967	12.980	-	12.980	0.727	-	0.727	-	28.914	-	28.914
1968	13.619	0.004	13.623	3.292	-	3.292	-	66.145	0.004	66.149
1969	13.151	0.070	13.221	5.626	-	5.626	-	74.038	0.072	74.110
1970	12.408	0.063	12.471	6.335	0.039	6.374	-	82.414	0.530	82.944
1971	11.466	0.077	11.543	6.714	0.039	6.753	-	77.627	0.710	78.337
1972	8.896	0.012	8.908	6.033	0.025	6.058	-	72.640	0.609	73.249
1973	10.064	0.098	10.162	5.803	0.051	5.854	-	72.195	0.811	73.006
1974	9.765	0.096	9.861	5.425	0.043	5.468	-	70.075	0.793	70.868
1975	8.754	0.089	8.843	4.598	0.031	4.629	-	69.111	0.765	69.876
1976	7.591	0.090	7.681	4.270	0.026	4.296	-	62.404	0.770	63.174
1977	5.981	0.086	6.067	3.306	0.044	3.350	-	56.096	0.863	56.959
1978	4.870	0.065	4.935	2.770	0.019	2.789	-	50.132	0.815	50.947
1979	4.344	0.080	4.424	2.284	0.014	2.298	-	43.046	0.635	43.681
1980	3.724	0.064	3.788	1.794	0.006	1.800	-	36.246	0.482	36.728
1981	2.938	0.048	2.986	1.435	0.005	1.440	-	31.076	0.537	31.613
1982	2.999	0.048	3.047	1.251	0.002	1.253	-	27.410	0.499	27.909
1983	3.017	0.045	3.062	0.964	0.004	0.968	-	24.763	0.381	25.144
1984	2.517	0.039	2.556	0.995	0.005	1.000	-	21.983	0.361	22.344
1985	2.165	0.026	2.191	0.915	0.004	0.919	-	16.943	0.224	17.167
1986	2.055	0.054	2.109	0.826	0.002	0.828	-	17.581	0.284	17.865
1987	2.059	0.030	2.089	0.689	0.001	0.690	-	16.191	0.227	16.418
1988	2.127	0.033	2.160	0.691	-	0.691	-	15.716	0.195	15.911
1989	1.875	0.024	1.899	1.085	-	1.085	-	15.365	0.024	15.389
1990	1.878	0.019	1.897	0.522	-	0.522	-	11.148	0.019	11.167
1991	1.962	0.023	1.985	1.048	-	1.048	0.002	15.340	0.023	15.363
1992	1.773	0.019	1.792	0.856	-	0.856	0.002	15.178	0.019	15.197
1993	1.576	0.018	1.594	0.742	-	0.742	0.098	13.853	0.018	13.871
1994	1.672	0.023	1.695	0.743	-	0.743	0.921	15.561	0.023	15.584
1995	1.712	0.017	1.729	0.722	-	0.722	0.922	15.513	0.017	15.530
1996	1.521	0.019	1.540	0.589	-	0.589	1.296	14.585	0.019	14.604
1997	1.065	0.012	1.077	0.602	-	0.602	0.645	12.145	0.012	12.157
1998	0.911	0.009	0.920	0.700	-	0.700	1.037	11.803	0.009	11.812
1999	0.794	-	0.794	0.645	-	0.645	0.914	10.905	-	10.905
2000	0.638	-	0.638	0.637	-	0.637	0.893	10.720	-	10.720
2001	0.609	-	0.609	0.574	-	0.574	1.222	11.497	-	11.497
2002	0.477	-	0.477	0.666	-	0.666	1.018	11.284	-	11.284
2003	0.425	-	0.425	0.537	-	0.537	0.849	10.059	-	10.059
TOTAL	228.350	1.400	229.750	77.413	0.360	77.773	9.820	1,292.357	10.750	1,303.107

Notes:

[5]Includes Hemlock pool.

[6]Includes Hemlock, Undefined, and B, C, D, and E pools.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports) and Alaska Department of Revenue.

North Slope (Billion Cubic Feet per Year)

	Badami			Barrow			Colville River						
	Badami			East Barrow	South Barrow	Walakpa	Alpine			Nanuq			TOTAL Colville
	gas	inj	net	gas	gas	gas	gas	inj	net	gas	inj	net	
1958	-	-	-	-	0.119	-			-				-
1959	-	-	-	-	0.132	-			-				-
1960	-	-	-	-	0.172	-			-				-
1961	-	-	-	-	0.172	-			-				-
1962	-	-	-	-	0.197	-			-				-
1963	-	-	-	-	0.211	-			-				-
1964	-	-	-	-	0.249	-			-				-
1965	-	-	-	-	0.389	-			-				-
1966	-	-	-	-	0.438	-			-				-
1967	-	-	-	-	0.475	-			-				-
1968	-	-	-	-	0.504	-			-				-
1969	-	-	-	-	0.582	-			-				-
1970	-	-	-	-	0.619	-			-				-
1971	-	-	-	-	0.627	-			-				-
1972	-	-	-	-	0.675	-			-				-
1973	-	-	-	-	0.707	-			-				-
1974	-	-	-	-	0.765	-			-				-
1975	-	-	-	-	0.799	-			-				-
1976	-	-	-	-	0.832	-			-				-
1977	-	-	-	-	0.879	-			-				-
1978	-	-	-	-	0.893	-			-				-
1979	-	-	-	-	0.913	-			-				-
1980	-	-	-	-	1.027	-			-				-
1981	-	-	-	0.037	1.009	-			-				-
1982	-	-	-	0.717	0.532	-			-				-
1983	-	-	-	0.689	0.541	-			-				-
1984	-	-	-	0.693	0.650	-			-				-
1985	-	-	-	0.632	0.678	-			-				-
1986	-	-	-	0.589	0.589	-			-				-
1987	-	-	-	0.590	0.622	-			-				-
1988	-	-	-	0.661	0.598	-			-				-
1989	-	-	-	0.475	0.758	-			-				-
1990	-	-	-	0.488	0.733	-			-				-
1991	-	-	-	0.583	0.662	-			-				-
1992	-	-	-	0.439	0.628	0.252			-				-
1993	-	-	-	0.259	0.441	0.585			-				-
1994	-	-	-	0.223	0.261	0.858			-				-
1995	-	-	-	0.099	0.052	1.109			-				-
1996	-	-	-	0.064	0.051	1.160			-				-
1997	-	-	-	0.114	0.041	1.126			-				-
1998	0.459	0.005	0.454	0.146	0.081	1.110	-	-	-				-
1999	1.693	1.718	-0.025	0.123	0.055	1.281	-		-				-
2000	4.557	4.020	0.537	0.090	0.037	1.352	2.091	-	2.091				2.091
2001	5.312	0.479	4.834	0.086	0.042	1.348	33.604	-	33.604	-	-	-	33.604
2002	7.172	6.126	1.045	0.093	0.061	1.251	39.872	35.009	4.863	0.298	-	-	4.863
2003	3.698	3.363	0.335	0.093	0.089	1.235	41.594	36.315	5.279	-	-	-	5.279
TOTAL	22.891	15.711	7.180	7.982	22.417	12.667	117.160	71.324	45.837	0.298	-	-	45.837

North Slope (Billion Cubic Feet per Year)

	Duck Island								Prudhoe Bay Satellites						
	Eider			Endicott[1]			Sag Delta	TOTAL Duck Island	Midnight Sun	Aurora			Borealis	Orion	Polaris
	gas	inj	net	gas	inj	net	gas		gas	gas	inj	net	gas	gas	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-		-			
1960	-	-	-	-	-	-	-	-	-	-		-			
1961	-	-	-	-	-	-	-	-	-	-		-			
1962	-	-	-	-	-	-	-	-	-	-		-			
1963	-	-	-	-	-	-	-	-	-	-		-			
1964	-	-	-	-	-	-	-	-	-	-		-			
1965	-	-	-	-	-	-	-	-	-	-		-			
1966	-	-	-	-	-	-	-	-	-	-		-			
1967	-	-	-	-	-	-	-	-	-	-		-			
1968	-	-	-	-	-	-	-	-	-	-		-			
1969	-	-	-	-	-	-	-	-	-	-		-			
1970	-	-	-	-	-	-	-	-	-	-		-			
1971	-	-	-	-	-	-	-	-	-	-		-			
1972	-	-	-	-	-	-	-	-	-	-		-			
1973	-	-	-	-	-	-	-	-	-	-		-			
1974	-	-	-	-	-	-	-	-	-	-		-			
1975	-	-	-	-	-	-	-	-	-	-		-			
1976	-	-	-	-	-	-	-	-	-	-		-			
1977	-	-	-	-	-	-	-	-	-	-		-			
1978	-	-	-	-	-	-	-	-	-	-		-			
1979	-	-	-	-	-	-	-	-	-	-		-			
1980	-	-	-	-	-	-	-	-	-	-		-			
1981	-	-	-	-	-	-	-	-	-	-		-			
1982	-	-	-	-	-	-	-	-	-	-		-			
1983	-	-	-	-	-	-	-	-	-	-		-			
1984	-	-	-	-	-	-	-	-	-	-		-			
1985	-	-	-	-	-	-	-	-	-	-		-			
1986	-	-	-	0.195	-	0.195	-	0.195	-	-		-			
1987	-	-	-	8.237	5.615	2.622	-	2.622	-	-		-			
1988	-	-	-	34.834	28.023	6.811	-	6.811	-	-		-			
1989	-	-	-	41.194	33.033	8.161	0.236	8.397	-	-		-			
1990	-	-	-	42.490	35.523	6.967	1.416	8.383	-	-		-			
1991	-	-	-	60.246	51.136	9.110	2.347	11.457	-	-		-			
1992	-	-	-	97.047	85.082	11.965	0.703	12.668	-	-		-			
1993	-	-	-	120.116	100.682	19.434	0.529	19.963	-	-		-			
1994	-	-	-	116.810	102.534	14.276	0.259	14.535	-	-		-			
1995	-	-	-	127.191	113.839	13.352	0.152	13.504	-	-		-			
1996	-	-	-	123.968	111.638	12.330	0.099	12.429	-	-		-			
1997	-	-	-	124.737	111.495	13.242	0.157	13.399	-	-		-			
1998	2.122	-	2.122	119.981	109.440	10.541	0.122	12.785	0.130	-		-			
1999	4.879	-	4.879	126.274	116.944	9.331	0.120	14.329	3.781	-		-			
2000	2.428	-	2.428	140.704	128.599	12.105	0.095	14.628	9.288	1.083	-	1.083			
2001	6.494	-	6.494	134.122	125.915	8.208	0.093	14.794	6.750	12.052	-	12.052	0.936		
2002	3.658	-	3.658	134.693	124.402	10.291	0.096	14.044	9.879	12.609	3.486	9.123	9.681	0.058	1.182
2003	2.813	-	2.813	141.556	129.458	12.098	0.064	14.975	3.500	11.971	0.357	11.614	9.466	0.312	1.000
TOTAL	22.394	-	22.394	1,694.395	1,513.356	181.038	6.487	209.919	33.328	37.714	3.843	33.871	20.082	0.370	2.182

North Slope (Billion Cubic Feet per Year)

	Prudhoe Bay Initial Oil PA			TOTAL Prudhoe Bay IPA & Satellites	Greater Point McIntyre Area (GPMA)[1]											TOTAL GPMA	TOTAL Prudhoe Bay Unit
	Prudhoe Bay[2]				Lisburne			Niakuk[2]	North Prudhoe Bay	Point McIntyre			West Beach				
	gas	inj	net		gas	inj	net	gas	gas	gas	inj	net	gas	inj	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1969	0.243	-	0.243	0.243	-	-	-	-	-	-	-	-	-		-	-	0.243
1970	1.037	-	1.037	1.037	-	-	-	-	-	-	-	-	-		-	-	1.037
1971	0.889	-	0.889	0.889	-	-	-	-	-	-	-	-	-		-	-	0.889
1972	0.658	-	0.658	0.658	-	-	-	-	-	-	-	-	-		-	-	0.658
1973	0.699	-	0.699	0.699	-	-	-	-	-	-	-	-	-		-	-	0.699
1974	2.022	-	2.022	2.022	-	-	-	-	-	-	-	-	-		-	-	2.022
1975	3.046	-	3.046	3.046	-	-	-	-	-	-	-	-	-		-	-	3.046
1976	5.077	-	5.077	5.077	-	-	-	-	-	-	-	-	-		-	-	5.077
1977	94.936	68.118	26.818	26.818	-	-	-	-	-	-	-	-	-		-	-	26.818
1978	307.966	271.854	36.112	36.112	-	-	-	-	-	-	-	-	-		-	-	36.112
1979	432.475	390.136	42.339	42.339	-	-	-	-	-	-	-	-	-		-	-	42.339
1980	597.148	546.510	50.638	50.638	-	-	-	-	-	-	-	-	-		-	-	50.638
1981	647.768	595.106	52.662	52.662	0.003	-	0.003	-	-	-	-	-	-		-	0.003	52.665
1982	756.884	697.812	59.072	59.072	0.374	-	0.374	-	-	-	-	-	-		-	0.374	59.446
1983	818.993	754.044	64.949	64.949	0.154	-	0.154	-	-	-	-	-	-		-	0.154	65.103
1984	846.674	768.899	77.775	77.775	0.343	-	0.343	-	-	-	-	-	-		-	0.343	78.118
1985	936.613	846.786	89.827	89.827	1.902	-	1.902	-	-	-	-	-	-		-	1.902	91.729
1986	970.290	882.882	87.408	87.408	8.677	-	8.677	-	-	-	-	-	-		-	8.677	96.085
1987	1,228.527	1,105.023	123.504	123.504	64.906	56.741	8.165	-	-	-	-	-	-		-	8.165	131.669
1988	1,404.992	1,248.094	156.898	156.898	94.670	87.815	6.855	-	-	-	-	-	-		-	6.855	163.753
1989	1,412.853	1,244.284	168.569	168.569	104.746	102.248	2.498	-	-	-	-	-	-		-	2.498	171.067
1990	1,481.462	1,317.106	164.356	164.356	107.592	101.542	6.050	-	-	-	-	-	-		-	6.050	170.406
1991	1,768.837	1,583.472	185.365	185.365	124.360	112.457	11.903	-	-	-	-	-	-		-	11.903	197.268
1992	1,951.156	1,761.397	189.759	189.759	154.468	141.598	12.870	-	-	-	-	-	-		-	12.870	202.629
1993	2,116.808	1,921.633	195.175	195.175	130.882	122.991	7.891	-	1.103	5.392	3.979	1.413	0.592		0.592	10.999	206.174
1994	2,402.584	2,204.235	198.349	198.349	101.260	99.748	1.512	2.471	2.646	38.795	34.461	4.334	1.119		1.119	12.082	210.431
1995	2,716.959	2,497.702	219.257	219.257	80.866	104.272	-23.406	7.241	2.482	46.637	21.687	24.950	0.446		0.446	11.713	230.970
1996	2,750.907	2,535.603	215.304	215.304	67.013	93.000	-25.987	8.757	0.206	56.584	30.444	26.140	2.720		2.720	11.836	227.140
1997	2,794.735	2,577.617	217.118	217.118	39.999	75.249	-35.250	10.523	-	70.009	35.945	34.064	2.739		2.739	12.076	229.194
1998	2,801.402	2,588.527	212.875	213.005	33.111	50.399	-17.288	8.381	0.018	70.828	49.276	21.552	0.545		0.545	13.208	226.213
1999	2,772.147	2,566.580	205.567	209.360	33.214	52.187	-18.973	8.469	0.114	62.586	41.672	20.915	4.452		4.452	14.976	219.884
2000	2,913.985	2,716.721	197.265	207.953	52.322	62.621	-10.299	5.069	0.049	57.664	43.549	14.115	5.638		5.638	14.572	216.887
2001	2,757.974	2,577.173	180.801	200.539	57.490	55.529	1.961	5.836	-	56.251	43.549	12.702	1.453		1.453	21.952	221.038
2002	2,761.753	2,570.664	191.090	211.199	63.745	52.214	11.531	4.287	-	57.465	55.078	2.387	0.048	2.606	-2.558	15.647	226.846
2003	2,840.910	2,617.182	223.728	249.619	66.748	52.165	14.583	3.386	-	51.777	64.363	-12.587	0.201	-	0.201	5.584	255.203
TOTAL	45,301.410	41,455.159	3,846.251	3,926.601	1,388.845	1,422.776	-33.931	64.420	6.618	573.988	424.003	149.984	19.954	2.606	17.348	204.439	4,119.497

Notes:

[1]Liquids from the Greater Point McIntyre Area flow to the Lisburne Production Center (LPC). At the LPC gas from these liquids is returned and reinjected into the GPMA fields. Consequently, production and injection data may appear to be anomolous.

[2]Niakuk production volumes for 1994-1999 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk

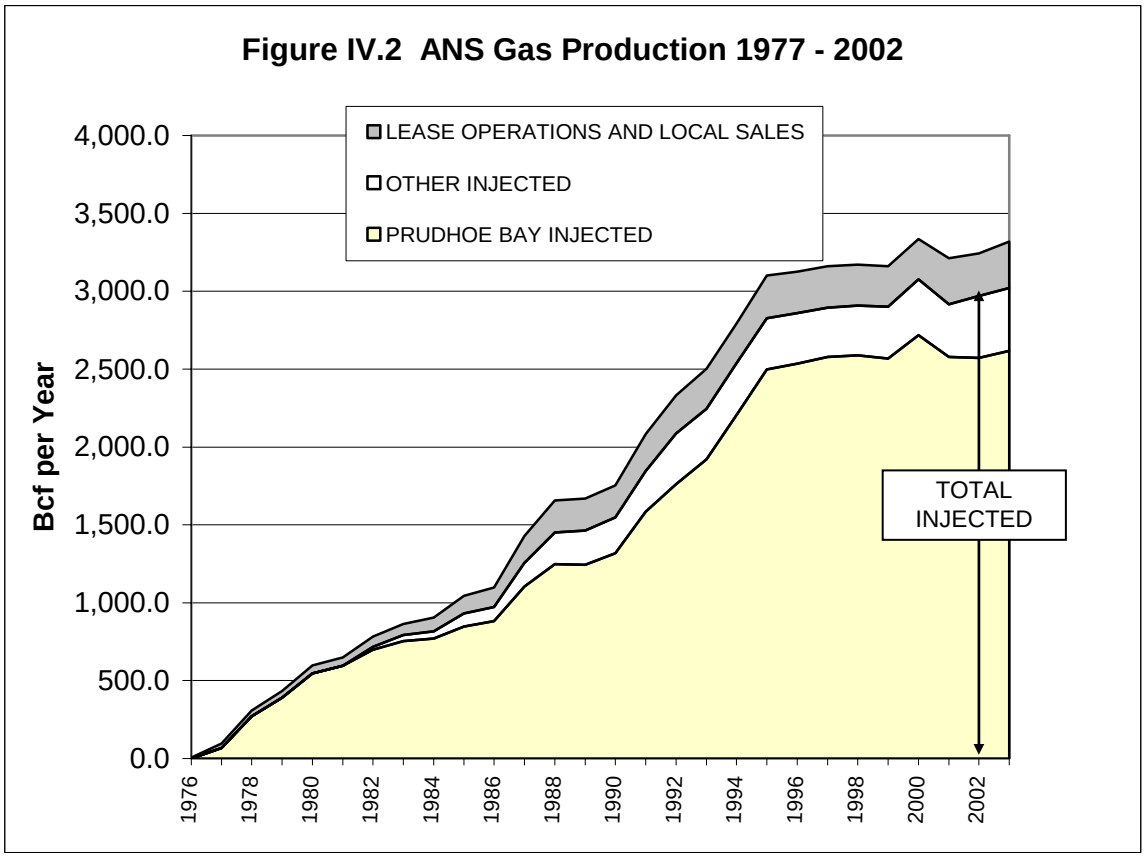
North Slope (Billion Cubic Feet per Year)

	Kuparuk River Unit													
	Kuparuk			Tabasco	Tarn			West Sak[1]			Meltwater			TOTAL Kuparuk River Unit
	gas	inj	net	gas	gas	inj	net	gas	inj	net	gas	inj	net	
1958	-	-	-	-	-	-	-	-			-	-	-	-
1959	-	-	-	-	-	-	-	-			-	-	-	-
1960	-	-	-	-	-	-	-	-			-	-	-	-
1961	-	-	-	-	-	-	-	-			-	-	-	-
1962	-	-	-	-	-	-	-	-			-	-	-	-
1963	-	-	-	-	-	-	-	-			-	-	-	-
1964	-	-	-	-	-	-	-	-			-	-	-	-
1965	-	-	-	-	-	-	-	-			-	-	-	-
1966	-	-	-	-	-	-	-	-			-	-	-	-
1967	-	-	-	-	-	-	-	-			-	-	-	-
1968	-	-	-	-	-	-	-	-			-	-	-	-
1969	-	-	-	-	-	-	-	-			-	-	-	-
1970	-	-	-	-	-	-	-	-			-	-	-	-
1971	-	-	-	-	-	-	-	-			-	-	-	-
1972	-	-	-	-	-	-	-	-			-	-	-	-
1973	-	-	-	-	-	-	-	-			-	-	-	-
1974	-	-	-	-	-	-	-	-			-	-	-	-
1975	-	-	-	-	-	-	-	-			-	-	-	-
1976	-	-	-	-	-	-	-	-			-	-	-	-
1977	-	-	-	-	-	-	-	-			-	-	-	-
1978	-	-	-	-	-	-	-	-			-	-	-	-
1979	-	-	-	-	-	-	-	-			-	-	-	-
1980	-	-	-	-	-	-	-	-			-	-	-	-
1981	0.615	-	0.615	-	-	-	-	-			-	-	-	0.615
1982	22.989	17.822	5.167	-	-	-	-	-			-	-	-	5.167
1983	44.391	38.277	6.114	-	-	-	-	0.005			-	-	-	6.114
1984	57.389	47.930	9.459	-	-	-	-	0.079			-	-	-	9.459
1985	104.279	85.909	18.370	-	-	-	-	0.134			-	-	-	18.370
1986	114.889	90.449	24.440	-	-	-	-	0.108			-	-	-	24.440
1987	125.089	89.191	35.898	-	-	-	-	-			-	-	-	35.898
1988	119.883	87.906	31.977	-	-	-	-	-			-	-	-	31.977
1989	107.519	83.323	24.196	-	-	-	-	-			-	-	-	24.196
1990	116.579	91.273	25.306	-	-	-	-	-			-	-	-	25.306
1991	123.207	95.982	27.225	-	-	-	-	-			-	-	-	27.225
1992	122.767	96.625	26.142	-	-	-	-	-			-	-	-	26.142
1993	120.599	94.339	26.260	-	-	-	-	-			-	-	-	26.260
1994	120.273	93.288	26.985	-	-	-	-	-			-	-	-	26.985
1995	112.418	84.317	28.101	-	-	-	-	-			-	-	-	28.101
1996	107.811	83.632	24.179	-	-	-	-	-			-	-	-	24.179
1997	105.644	85.893	19.751	-	-	-	-	-			-	-	-	19.751
1998	117.517	103.604	13.913	0.112	4.476	1.195	3.281	0.213			-	-	-	17.306
1999	117.193	98.330	18.863	0.305	13.395	16.502	-3.107	0.385			-	-	-	16.061
2000	109.638	97.762	11.875	0.203	17.777	16.552	1.225	0.399			-	-	-	13.304
2001	105.305	91.823	13.482	0.180	15.538	15.039	0.499	0.429			0.081	-	0.081	14.241
2002	100.938	81.157	19.782	0.159	13.101	16.755	-3.654	0.635	5.045	-4.410	4.145	6.345	-2.200	9.676
2003	107.454	86.331	21.123	0.188	12.835	18.430	-5.596	0.813	0.171	0.642	5.595	5.562	0.033	16.391
TOTAL	2,284.387	1,825.163	459.223	1.147	77.122	84.474	-7.351	3.200	5.216	-3.768	9.820	11.906	-2.086	447.165

North Slope (Billion Cubic Feet per Year)

	Milne Popint Unit										NORTH SLOPE		
	Kuparuk River PA			Sag River			Schrader Bluff			TOTAL Milne Point Unit	TOTAL GAS	TOTAL INJECTED	TOTAL NET
	gas	inj	net	gas	inj	net	gas	inj	net				
1958	-	-	-	-			-			-	0.119	-	0.119
1959	-	-	-	-			-			-	0.132	-	0.132
1960	-	-	-	-			-			-	0.172	-	0.172
1961	-	-	-	-			-			-	0.172	-	0.172
1962	-	-	-	-			-			-	0.197	-	0.197
1963	-	-	-	-			-			-	0.211	-	0.211
1964	-	-	-	-			-			-	0.249	-	0.249
1965	-	-	-	-			-			-	0.389	-	0.389
1966	-	-	-	-			-			-	0.438	-	0.438
1967	-	-	-	-			-			-	0.475	-	0.475
1968	-	-	-	-			-			-	0.504	-	0.504
1969	-	-	-	-			-			-	0.825	-	0.825
1970	-	-	-	-			-			-	1.656	-	1.656
1971	-	-	-	-			-			-	1.516	-	1.516
1972	-	-	-	-			-			-	1.333	-	1.333
1973	-	-	-	-			-			-	1.406	-	1.406
1974	-	-	-	-			-			-	2.787	-	2.787
1975	-	-	-	-			-			-	3.845	-	3.845
1976	-	-	-	-			-			-	5.909	-	5.909
1977	-	-	-	-			-			-	95.815	68.118	27.697
1978	-	-	-	-			-			-	308.859	271.854	37.005
1979	-	-	-	-			-			-	433.388	390.136	43.252
1980	-	-	-	-			-			-	598.175	546.510	51.665
1981	-	-	-	-			-			-	649.432	595.106	54.326
1982	-	-	-	-			-			-	781.496	715.634	65.862
1983	-	-	-	-			-			-	864.773	792.321	72.452
1984	-	-	-	-			-			-	905.828	816.829	88.999
1985	0.253	-	0.253	-			-			0.253	1,044.491	932.695	111.796
1986	1.644	0.197	1.447	-			-			1.447	1,096.981	973.528	123.453
1987	0.011	-	0.011	-			-			0.011	1,427.982	1,256.570	171.412
1988	-	-	-	-			-			-	1,655.638	1,451.838	203.800
1989	0.978	0.320	0.658	-			-			0.658	1,668.759	1,463.208	205.551
1990	2.718	1.401	1.317	-			-			1.317	1,753.478	1,546.845	206.633
1991	3.515	1.704	1.811	-			0.244		0.244	2.055	2,084.001	1,844.751	239.250
1992	3.015	1.632	1.383	-			0.536		0.536	1.919	2,331.011	2,086.334	244.677
1993	2.967	1.836	1.131	-			0.518		0.518	1.649	2,500.791	2,245.460	255.331
1994	3.524	2.305	1.219	-			0.515		0.515	1.734	2,791.598	2,536.571	255.027
1995	4.340	3.399	0.941	0.113			0.656		0.656	1.597	3,100.761	2,825.216	275.545
1996	6.120	4.307	1.813	0.299			0.464		0.464	2.277	3,126.223	2,858.624	267.599
1997	9.463	6.998	2.465	0.437			0.644		0.644	3.109	3,160.368	2,893.197	267.171
1998	8.949	6.351	2.598	0.179		-	1.008		1.008	3.606	3,170.890	2,908.797	262.093
1999	8.371	6.137	2.234	0.019		-	1.199		1.199	3.433	3,160.054	2,900.069	259.985
2000	8.207	6.195	2.012	-		-	1.480		1.480	3.492	3,334.155	3,076.018	258.137
2001	8.631	7.498	1.133	0.228	-	-	2.380		2.380	3.513	3,212.615	2,917.005	295.610
2002	7.054	8.697	-1.643	0.179	0.653	-0.474	9.272	0.927	8.345	6.227	3,243.383	2,969.164	274.219
2003	5.337	7.757	-2.420	0.121	0.179	-0.058	6.095	-	6.095	3.617	3,318.850	3,021.633	297.217
TOTAL	85.097	66.734	18.362	1.575	0.832	-0.532	25.011	0.927	24.084	41.914	51,842.960	46,904.031	4,938.929

North Slope



Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

Cook Inlet (Billion Cubic Feet per Year)

	Albert Kaloa	Beaver Creek			Beluga River	Birch Hill	Cannery Loop[1]	Nilchik[2]	Granite Point	Ivan River	Kenai[3]	Lewis River	McArthur River (TBU)	Middle Ground Shoal	Moquawkie Lone Cr	Nicolai Creek
	gas	gas	inj	net	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	0.215	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	1.460	-	-	-	-	-
1963	-	-	-	-	0.014	-	-	-	-	-	3.106	-	-	-	-	-
1964	-	-	-	-	0.137	-	-	-	-	-	4.493	-	-	-	-	-
1965	-	-	-	-	-	0.065	-	-	-	-	5.985	-	-	-	-	-
1966	-	-	-	-	-	-	-	0.019	-	-	33.375	-	-	1.200	-	-
1967	-	-	-	-	0.168	-	-	-	4.890	-	39.624	-	0.220	3.215	0.034	-
1968	-	-	-	-	2.018	-	-	-	10.036	-	46.014	-	6.155	6.654	0.353	0.026
1969	-	-	-	-	3.038	-	-	-	8.043	-	59.340	-	14.194	6.006	0.514	0.387
1970	0.095	-	-	-	3.571	-	-	-	9.211	-	80.612	-	19.688	6.137	0.083	0.202
1971	0.024	-	-	-	4.055	-	-	-	7.753	-	72.184	-	19.304	5.147	-	0.141
1972	-	0.002	-	0.002	4.142	-	-	-	5.773	-	76.007	-	19.722	4.075	-	0.066
1973	-	0.207	-	0.207	4.929	-	-	-	4.518	-	71.345	-	19.063	4.826	-	0.006
1974	-	0.150	0.019	0.131	5.596	-	-	-	3.265	-	68.485	-	19.599	4.260	-	0.011
1975	-	0.322	-	0.322	6.980	-	-	-	3.390	-	77.175	-	21.471	4.199	-	0.083
1976	-	0.261	0.091	0.170	11.211	-	-	-	3.205	-	79.467	-	19.027	4.347	-	0.108
1977	-	0.203	0.100	0.103	13.353	-	-	-	3.634	-	81.886	-	19.706	4.108	-	0.032
1978	-	0.329	0.144	0.185	14.253	-	-	-	3.860	-	97.290	-	18.585	3.290	-	-
1979	-	0.182	0.079	0.103	16.994	-	-	-	3.287	-	97.029	-	16.605	2.744	-	-
1980	-	0.180	0.029	0.151	17.002	-	-	-	3.233	-	98.846	-	15.590	2.628	-	-
1981	-	0.217	0.020	0.197	17.248	-	-	-	3.509	-	105.800	-	15.206	2.502	-	-
1982	-	0.396	0.037	0.359	18.653	-	-	-	2.780	-	115.913	-	16.240	2.374	-	-
1983	-	8.344	0.031	8.313	18.084	-	-	-	2.578	-	112.978	-	14.375	2.663	-	-
1984	-	9.335	-	9.335	19.833	-	-	-	2.340	-	110.109	0.696	15.076	2.726	-	-
1985	-	10.927	-	10.927	22.571	-	-	-	2.147	-	115.842	1.644	10.676	2.622	-	-
1986	-	17.773	-	17.773	25.357	-	-	-	2.415	-	82.470	1.338	13.560	1.593	-	-
1987	-	15.528	-	15.528	23.971	-	-	-	2.431	-	90.014	0.345	13.277	1.586	-	-
1988	-	14.346	-	14.346	25.586	-	9.400	-	2.543	-	76.299	0.045	16.722	1.635	-	-
1989	-	12.321	-	12.321	30.126	-	11.255	-	2.251	-	65.706	0.095	31.000	1.965	-	-
1990	-	12.474	-	12.474	39.512	-	12.502	-	1.431	0.676	38.393	1.485	51.456	2.579	-	-
1991	-	10.403	-	10.403	38.494	-	12.318	-	1.586	2.132	25.581	1.420	61.196	1.587	-	-
1992	-	7.368	-	7.368	36.534	-	10.635	-	2.246	1.774	24.187	0.706	70.070	2.377	-	-
1993	-	6.336	-	6.336	31.739	-	9.516	-	2.444	8.238	23.826	0.383	62.512	2.941	-	-
1994	-	1.304	-	1.304	34.212	-	6.361	-	2.077	15.996	18.853	0.244	50.027	3.025	-	-
1995	-	1.915	-	1.915	35.645	-	5.535	-	1.942	12.027	16.484	0.126	54.914	2.138	-	-
1996	-	3.042	-	3.042	36.930	-	2.072	-	2.251	6.605	13.294	0.114	67.275	0.852	-	-
1997	-	4.626	-	4.626	35.002	-	3.130	-	2.551	5.297	12.672	0.066	66.838	1.051	-	-
1998	-	3.743	-	3.743	33.391	-	3.021	-	2.635	4.532	9.736	0.102	73.822	1.882	-	-
1999	-	3.288	-	3.288	35.987	-	2.87102	-	2.464	3.579	9.916	0.246	68.997	2.751	-	-
2000	-	4.793	-	4.793	38.750	-	4.692	-	2.209	2.620	12.833	0.134	65.016	1.485	-	-
2001	-	5.340	-	5.340	41.786	-	6.304	-	1.936	3.799	19.964	0.220	62.264	1.319	-	-
2002	-	8.548	-	8.548	44.039	-	5.016	-	1.658	4.303	22.154	0.898	51.515	0.918	-	0.605
2003	-	7.868	-	7.868	56.252	-	6.143	3.044	1.378	2.471	28.586	0.575	39.216	0.654	1.015	0.262
TOTAL	0.119	172.072	0.550	171.522	847.162	0.065	110.771	3.063	125.900	74.049	2,245.548	10.882	1,220.179	108.060	1.999	1.929

Notes:

[1] Cannery Loop includes CLU Beluga, CLU Upper Tyonek, CLU Tyonek D, and CLU Sterling Undefined in the Kenai formation.

2 Ninilchik includes Falls Creek, Grassim Oskolkof, and Susan Dionne participating areas.

3 Kenai includes Sterling #3, 4, 5.1, 5.2, and 6 Pools, Beluga Undefined, and Tyonek.

Cook Inlet (Billion Cubic Feet per Year)

																COOK INLET		
	North Cook Inlet	North Fork	North Trading Bay Unit[3]	Pretty Creek	Re-Doubt	Sterling	Stump Lake	Swanson River[4]			Trading Bay[5]	West Fork	West Fore-land	West McArthur River	Wolf Lake	TOTAL GROSS	TOTAL INJECTED	TOTAL NET
	gas	gas	gas	gas	gas	gas	gas	gas	inj	net	gas	gas	gas	gas	gas			
1958	-	-	-	-	-	-	-	0.006	-	0.006	-	-	-	-	-	0.006	-	0.006
1959	-	-	-	-	-	-	-	0.027	-	0.027	-	-	-	-	-	0.027	-	0.027
1960	-	-	-	-	-	-	-	0.119	46.482	-	-	-	-	-	-	0.119	46.482	-
1961	-	-	-	-	-	-	-	1.293	-	1.293	-	-	-	-	-	1.508	-	1.508
1962	-	-	-	-	-	0.025	-	2.071	0.259	1.812	-	-	-	-	-	3.556	0.259	3.297
1963	-	-	-	-	-	0.046	-	7.646	6.478	1.168	-	-	-	-	-	10.812	6.478	4.334
1964	-	-	-	-	-	0.058	-	7.176	5.620	1.556	-	-	-	-	-	11.864	5.620	6.244
1965	-	-	-	-	-	0.120	-	5.973	4.843	1.130	-	-	-	-	-	12.143	4.843	7.300
1966	-	0.105	-	-	-	0.157	-	6.363	28.770	-	-	-	-	-	-	41.219	28.770	12.449
1967	-	-	-	-	-	0.180	-	13.541	37.944	-	0.722	-	-	-	-	62.594	37.944	24.650
1968	-	-	0.045	-	-	0.198	-	25.434	58.316	-	2.916	-	-	-	-	99.849	58.316	41.533
1969	7.881	-	1.175	-	-	0.265	-	40.756	67.215	-	5.944	-	-	-	-	147.543	67.215	80.328
1970	40.947	-	0.725	-	-	0.265	-	50.396	73.139	-	6.430	-	-	-	-	218.362	73.139	145.223
1971	45.024	-	0.419	-	-	0.267	-	66.569	73.892	-	8.678	-	-	-	-	229.565	73.892	155.673
1972	41.580	-	0.635	-	-	0.172	-	67.441	76.133	-	5.033	-	-	-	-	224.648	76.133	148.515
1973	42.709	-	0.588	-	-	0.027	-	74.067	87.482	-	2.951	-	-	-	-	225.236	87.482	137.754
1974	44.238	-	0.600	-	-	0.032	-	80.869	86.793	-	2.712	-	-	-	-	229.817	86.812	143.005
1975	45.622	-	0.478	-	-	0.035	-	90.665	97.976	-	2.134	-	-	-	-	252.554	97.976	154.578
1976	45.091	-	0.318	-	-	0.035	-	101.427	113.279	-	2.155	-	-	-	-	266.652	113.370	153.282
1977	47.201	-	0.272	-	-	0.029	-	106.911	118.279	-	2.619	-	-	-	-	279.954	118.379	161.575
1978	46.757	-	0.217	-	-	0.024	-	106.934	114.557	-	2.211	0.052	-	-	-	293.802	114.701	179.101
1979	49.448	-	0.153	-	-	0.025	-	116.266	120.268	-	1.560	0.770	-	-	-	305.063	120.347	184.716
1980	41.540	-	0.197	-	-	0.026	-	118.855	120.636	-	1.355	0.476	-	-	-	299.928	120.665	179.263
1981	49.486	-	0.264	-	-	0.023	-	103.592	106.137	-	1.160	0.030	-	-	-	299.037	106.157	192.880
1982	45.368	-	0.445	-	-	0.024	-	105.654	113.023	-	1.187	0.086	-	-	-	309.120	113.060	196.060
1983	47.877	-	0.660	-	-	0.022	-	97.505	95.353	2.152	0.896	0.067	-	-	-	306.049	95.384	210.665
1984	46.981	-	0.649	-	-	0.018	-	96.710	93.687	3.023	0.911	0.037	-	-	-	305.421	93.687	211.734
1985	45.819	-	0.526	-	-	0.012	-	92.104	89.025	3.079	1.005	0.022	-	-	-	305.917	89.025	216.892
1986	43.838	-	0.513	0.067	-	0.002	-	95.083	93.602	1.481	0.866	-	-	-	-	284.875	93.602	191.273
1987	42.889	-	0.537	0.776	-	-	-	84.063	87.013	-2.950	0.897	-	-	-	-	276.314	87.013	189.301
1988	44.989	-	0.270	0.871	-	-	-	102.600	99.734	2.866	1.041	-	-	-	-	296.347	99.734	196.613
1989	45.287	-	0.217	0.641	-	-	-	104.094	107.802	-3.708	1.215	-	-	-	-	306.173	107.802	198.371
1990	45.014	-	0.060	0.607	-	-	0.528	104.395	106.031	-1.636	0.407	-	-	-	-	311.519	106.031	205.488
1991	44.695	-	0.079	0.742	-	-	1.608	105.057	105.157	-0.100	0.865	0.460	-	-	-	308.223	105.157	203.066
1992	44.411	-	0.013	0.762	-	-	1.504	104.533	104.724	-0.191	0.692	1.364	-	-	-	309.176	104.724	204.452
1993	45.529	-	-	0.333	-	0.007	0.778	97.701	93.052	4.649	0.619	0.625	-	0.031	-	293.558	93.052	200.506
1994	52.689	-	-	0.203	-	0.224	0.454	124.420	97.148	27.272	0.648	0.206	-	0.216	-	311.159	97.148	214.011
1995	53.541	-	-	0.256	-	0.184	0.288	101.781	73.086	28.695	0.526	0.016	-	0.231	-	287.549	73.086	214.463
1996	55.976	-	0.023	0.301	-	0.037	0.185	76.159	42.820	33.339	0.386	-	-	0.309	-	265.811	42.820	222.991
1997	52.466	-	0.511	0.383	-	0.005	0.132	51.898	23.163	28.735	1.122	-	-	0.152	-	237.902	23.163	214.739
1998	53.964	-	0.695	0.435	-	-	0.080	36.917	11.089	25.828	0.843	-	-	0.241	-	226.039	11.089	214.950
1999	51.629	-	0.241	0.028	-	0.125	0.054	37.483	7.731	29.752	0.445	-	-	0.212	-	220.318	7.731	212.587
2000	52.841	-	0.152	-	-	0.329	0.032	32.421	2.729	29.692	0.469	-	-	0.211	-	218.988	2.729	216.258
2001	55.531	-	-	0.080	-	0.149	0.000	30.405	8.356	22.049	0.420	-	-	0.288	0.114	229.919	8.356	221.563
2002	54.574	-	-	1.359	0.008	0.552	-	14.687	1.910	12.777	0.449	-	0.060	0.239	0.300	211.882	1.910	209.972
2003	47.920	-	0.101	0.428	0.673	0.358	0.000	9.292	0.004	9.287	0.263	-	0.940	0.200	0.240	207.877	0.004	207.873
TOTAL	1,621.352	0.105	11.778	8.272	0.681	4.056	5.644	2,899.359	2,900.737	263.084	64.752	4.211	1.000	2.330	0.654	9,545.993	2,901.287	6,644.706

Notes:

[3] Based on dry gas quantities reported for undefined pools in the Trading Bay Unit.

[4] Gas from other fields was injected into the Swanson River field to maintain reservoir pressure. Consequently, production and injection volumes may appear anomalous. The very high gas injection volume for 1960 was an accounting adjustment.

[5] Based on quantities reported for Hemlock, Middle Kenai B through E, G-NE Hemlock-NE, W Foreland, and M. Kenai Unallocated in the Trading Bay Unit.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports).

North Slope (Millions of Barrels per Year)

	Badami	Colville River	Northstar	Duck Island Unit	Prudhoe Bay IPAs[2]	Prudhoe Bay Satellites	Greater Pt McIntyre Area[3]	PBU IPA+Sat+ GPMA	Kuparuk IPA	Kuparuk Satellites	KRU IPA+Sat	Milne Point Unit	Pt Thomson Unit	Other North Slope[4]	NPRA[5]	**North Slope**
1970	-	-	-	-	0.3	-	-	0.3	0.0	-	0.0	-	-	-	-	0.3
1971	-	-	-	-	0.3	-	-	0.3	-	-	-	-	-	-	-	0.3
1972	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	-	0.1
1973	-	-	-	-	0.1	-	-	0.1	-	-	-	-	-	-	-	0.1
1974	-	-	-	-	0.5	-	-	0.5	-	-	-	-	-	-	-	0.5
1975	-	-	-	-	0.7	-	-	0.7	-	-	-	-	-	-	-	0.7
1976	-	-	-	-	1.0	-	-	1.0	-	-	-	-	-	-	-	1.0
1977	-	-	-	-	113.2	-	-	113.2	-	-	-	-	-	-	-	113.2
1978	-	-	-	-	397.7	-	-	397.7	-	-	-	-	-	-	-	397.7
1979	-	-	-	-	468.4	-	-	468.4	-	-	-	-	-	-	-	468.4
1980	-	-	-	-	555.6	-	-	555.6	-	-	-	-	-	-	-	555.6
1981	-	-	-	-	555.6	-	0.0	555.6	1.1	-	1.1	-	-	-	-	556.7
1982	-	-	-	-	559.4	-	0.2	559.6	32.4	-	32.4	-	-	-	-	592.0
1983	-	-	-	-	561.1	-	0.1	561.2	39.9	0.0	39.9	-	-	-	-	601.1
1984	-	-	-	-	562.3	-	0.3	562.6	46.1	0.1	46.2	-	-	-	-	608.8
1985	-	-	-	-	568.6	-	1.1	569.7	79.7	0.3	80.0	0.7	-	-	-	650.4
1986	-	-	-	0.0	561.8	-	3.6	565.4	95.0	0.3	95.3	4.7	-	-	-	665.3
1987	-	-	-	8.8	586.7	-	16.7	603.3	103.7	-	103.7	0.0	-	-	-	715.8
1988	-	-	-	37.9	578.7	-	16.1	594.8	111.1	-	111.1	-	-	-	-	743.9
1989	-	-	-	36.9	522.9	-	14.8	537.7	109.8	-	109.8	3.7	-	-	-	688.1
1990	-	-	-	38.6	486.2	-	15.9	502.1	107.2	-	107.2	6.6	-	-	-	654.5
1991	-	-	-	42.5	486.7	-	14.7	501.4	113.6	-	113.6	7.5	-	-	-	664.9
1992	-	-	-	43.1	456.5	-	14.0	470.5	118.5	-	118.5	6.9	-	-	-	639.0
1993	-	-	-	40.8	409.7	-	18.5	428.2	115.2	-	115.2	6.8	-	-	-	590.9
1994	-	-	-	35.8	374.3	-	50.7	425.0	111.8	-	111.8	6.7	-	-	-	579.3
1995	-	-	-	34.4	340.4	-	65.2	405.6	107.0	-	107.0	8.7	-	-	-	555.7
1996	-	-	-	27.7	312.6	-	75.6	388.2	99.5	-	99.5	14.1	-	-	-	529.4
1997	-	-	-	22.9	284.0	-	73.7	357.7	96.0	0.0	96.0	19.0	-	-	-	495.6
1998	0.7	-	-	18.6	252.8	0.1	61.9	314.8	91.7	4.6	96.3	20.4	-	-	-	450.8
1999	1.2	-	-	15.7	223.8	1.7	47.5	273.0	82.4	12.7	95.0	19.7	-	-	-	404.5
2000	0.9	2.2	-	13.5	217.2	2.1	36.1	255.4	74.1	12.2	86.3	19.1	-	-	-	377.4
2001	0.7	28.7	1.3	11.8	194.2	4.8	29.6	228.6	68.3	11.5	79.8	19.3	-	-	-	370.2
2002	0.6	35.0	17.9	10.3	177.6	14.9	24.6	217.1	58.9	18.5	77.4	18.7	-	-	-	377.0
2003	0.3	35.6	23.0	10.6	166.3	18.6	22.3	207.2	58.5	18.9	77.4	18.7	-	-	-	372.7
2004	-	36.8	24.3	9.2	156.7	18.9	21.5	197.1	54.5	19.4	73.9	18.8	-	-	-	360.0
2005	-	39.3	21.4	8.4	147.7	20.7	20.9	189.3	52.0	22.6	74.6	18.8	-	-	-	351.8
2006	-	43.3	17.1	8.1	142.7	24.7	19.5	186.9	49.6	27.7	77.3	19.3	-	-	-	352.0
2007	-	47.9	13.7	7.5	137.7	27.7	17.7	183.1	46.7	33.7	80.4	20.0	-	2.1	-	354.7
2008	-	46.8	10.9	6.9	133.1	28.9	16.1	178.1	44.1	36.9	81.0	20.1	-	3.7	-	347.4
2009	-	42.6	8.8	6.4	128.3	28.2	14.7	171.2	41.8	38.1	79.9	19.9	6.4	13.2	-	348.3
2010	-	37.9	7.0	5.9	121.6	26.3	13.6	161.5	39.8	38.5	78.3	20.0	19.5	25.2	4.3	355.3
2011	-	32.7	5.7	5.5	117.2	24.5	12.6	154.3	37.9	37.3	75.3	20.1	24.6	30.3	11.1	348.4
2012	-	28.1	4.7	5.2	112.9	22.8	11.7	147.5	36.3	35.1	71.3	20.1	23.0	32.1	17.2	332.0
2013	-	24.3	4.0	4.8	108.9	21.3	11.0	141.1	34.7	32.7	67.4	20.2	21.5	31.6	23.1	315.0
2014	-	21.1	3.5	4.5	105.2	19.8	10.3	135.3	33.4	30.5	63.9	20.3	20.1	32.2	24.4	300.9
2015	-	18.5	3.1	4.3	99.9	18.5	9.7	128.1	32.1	28.6	60.7	19.8	18.8	30.6	21.9	284.0
2016	-	16.3	2.8	4.1	96.8	17.3	9.1	123.3	31.0	26.6	57.5	18.8	17.6	26.8	19.4	267.3
2017	-	14.5	2.6	3.9	95.3	16.2	8.6	120.1	29.9	24.4	54.3	18.0	16.4	23.8	17.1	253.5
2018	-	13.0	2.4	3.7	93.1	15.1	8.1	116.4	28.9	22.4	51.2	17.2	15.4	21.2	15.1	240.5
2019	-	11.7	2.2	3.6	90.0	14.1	7.7	111.8	28.0	20.5	48.5	16.4	14.4	18.9	13.4	227.4
2020	-	10.6	2.1	3.4	79.7	13.2	7.3	100.2	27.1	19.0	46.1	15.6	13.4	16.9	11.8	208.2
2021	-	9.5	1.9	3.3	77.0	12.3	7.0	96.2	26.3	17.6	43.9	14.9	12.6	15.0	10.5	197.3
2022	-	8.7	1.8	3.2	74.4	11.5	6.7	92.5	25.5	16.3	41.8	14.2	11.7	13.4	9.3	187.3

Notes:

[1] Forecast based on AOGCC Monthly Production Reports through 2003. Figures include NGLs.

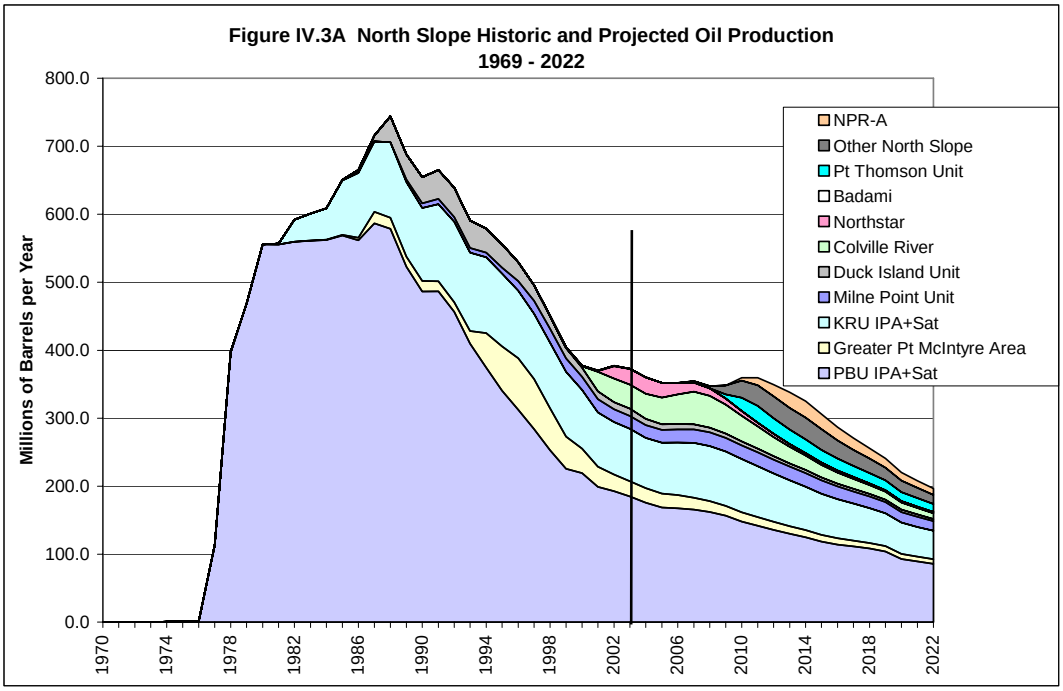
[2] Oil Rim and Gas Cap.

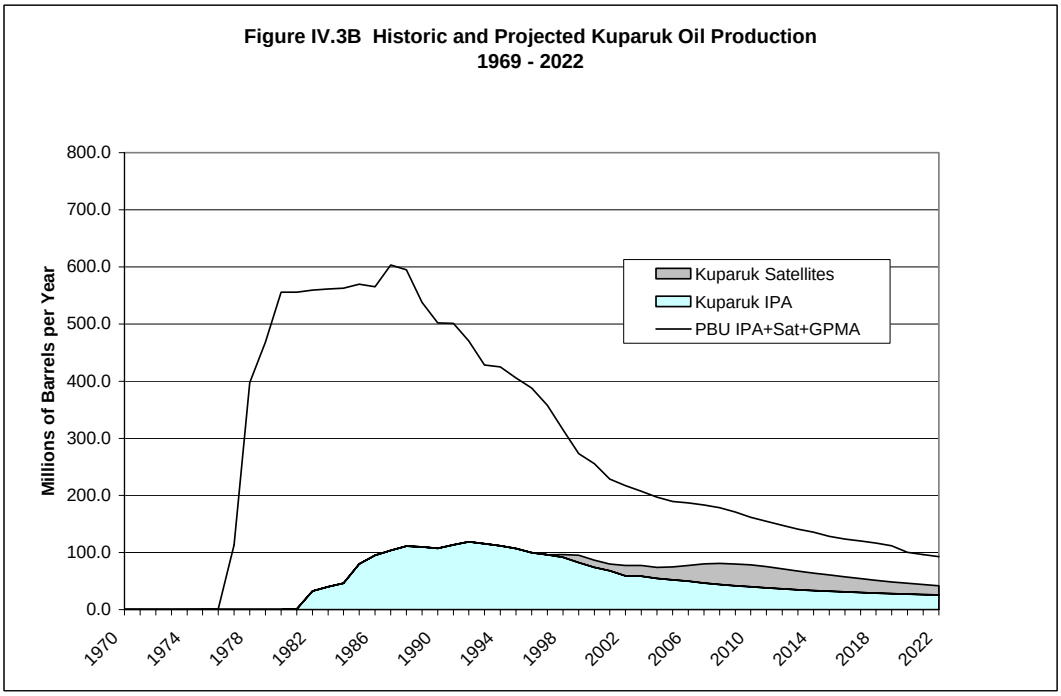
[3] Includes Lisburne, Niakuk, North Prudhoe Bay, Point MacIntyre PA, and West Beach.

[4] Risked Production for North Slope (excludes 1002 Area).

[5] Based on U.S.G.S. estimates.

North Slope (Millions of Barrels per Year)



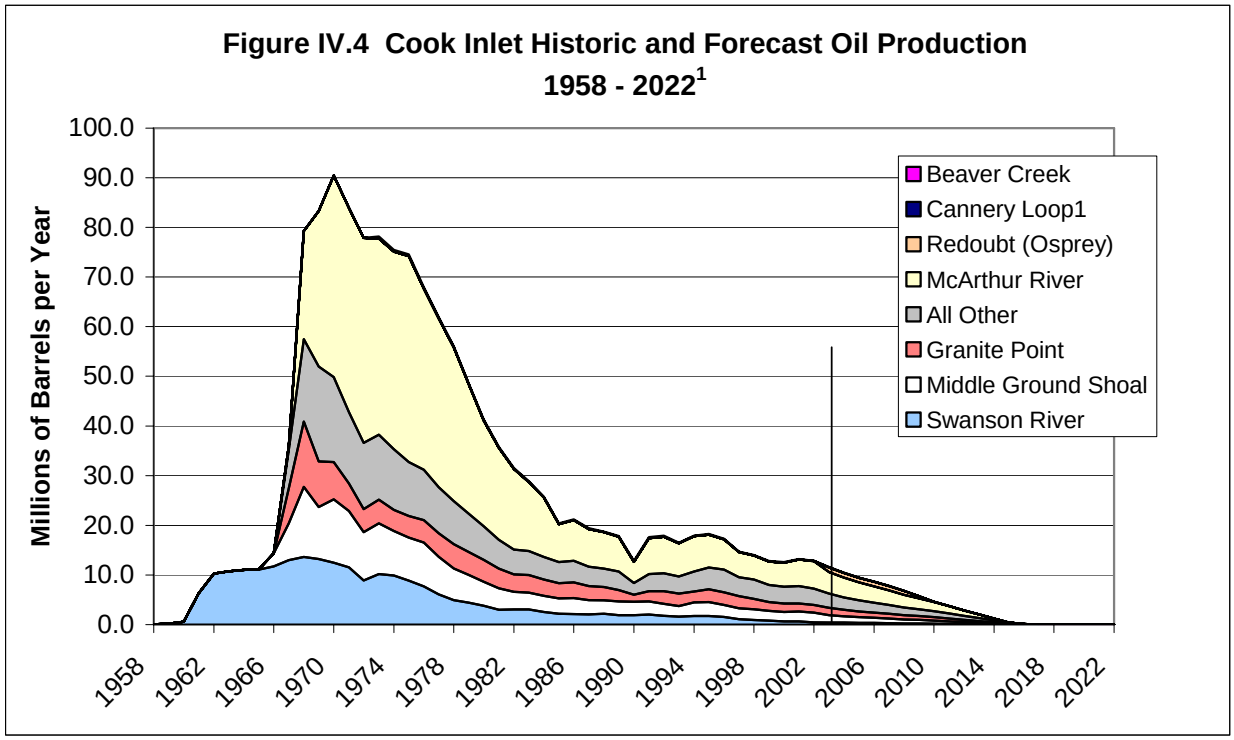


Note:
Figures IV.3A and IV.3B correspond to Table IV.7.

Cook Inlet (Millions of Barrels per Year)

	Beaver Creek[1]	Granite Point[1]	McArthur River	Middle Ground Shoal	Redoubt (Osprey)	Swanson River	Trading Bay[1]	West McArthur River[1]	Kenai and NTB	**TOTAL OIL and NGL[2]**
1958	-	-	-	-	-	0.036	-	-	-	0.036
1959	-	-	-	-	-	0.187	-	-	-	0.187
1960	-	-	-	-	-	0.558	-	-	-	0.558
1961	-	-	-	-	-	6.327	-	-	-	6.327
1962	-	-	-	-	-	10.259	-	-	-	10.259
1963	-	-	-	-	-	10.740	-	-	-	10.740
1964	-	-	-	-	-	11.054	-	-	-	11.054
1965	-	0.002	0.001	0.027	-	11.099	0.002	-	-	11.131
1966	-	-	0.003	2.649	-	11.712	-	-	-	14.364
1967	-	7.052	0.749	7.404	-	12.980	0.727	-	0.002	28.914
1968	-	13.131	21.782	14.134	0.002	13.623	3.292	-	0.185	66.149
1969	-	9.183	31.301	10.467	-	13.221	5.626	-	4.312	74.110
1970	-	7.522	40.591	12.719	-	12.471	6.374	-	3.267	82.944
1971	-	5.577	41.130	11.304	-	11.543	6.753	-	2.030	78.337
1972	0.002	4.663	41.344	9.719	-	8.908	6.058	-	2.555	73.249
1973	0.416	4.767	39.545	10.239	-	10.162	5.854	-	2.023	73.006
1974	0.375	4.237	39.799	9.001	-	9.861	5.468	-	2.127	70.868
1975	0.322	4.361	41.520	8.670	-	8.843	4.629	-	1.531	69.876
1976	0.302	4.471	36.463	8.864	-	7.681	4.296	-	1.097	63.174
1977	0.276	4.711	33.968	7.617	-	6.067	3.350	-	0.970	56.959
1978	0.223	4.867	30.953	6.382	-	4.935	2.789	-	0.798	50.947
1979	0.211	4.613	25.981	5.545	-	4.424	2.298	-	0.609	43.681
1980	0.214	4.394	21.306	4.854	-	3.788	1.800	-	0.372	36.728
1981	0.180	3.975	18.506	4.291	-	2.986	1.440	-	0.235	31.613
1982	0.182	3.467	16.255	3.573	-	3.047	1.253	-	0.132	27.909
1983	0.170	3.550	13.896	3.381	-	3.062	0.968	-	0.117	25.144
1984	0.159	3.287	12.024	3.238	-	2.556	1.000	-	0.080	22.344
1985	0.146	3.052	7.648	3.098	-	2.191	0.919	-	0.113	17.167
1986	0.158	3.169	8.170	3.211	-	2.109	0.828	-	0.220	17.865
1987	0.185	2.803	7.571	2.834	-	2.089	0.690	-	0.246	16.418
1988	0.141	2.677	7.305	2.742	-	2.160	0.691	-	0.195	15.911
1989	0.227	2.275	6.955	2.769	-	1.899	1.085	-	0.179	15.389
1990	0.212	1.462	4.265	2.688	-	1.897	0.522	-	0.121	11.167
1991	0.179	2.064	7.247	2.670	-	1.985	1.048	0.002	0.168	15.363
1992	0.175	2.522	7.397	2.423	-	1.792	0.856	0.002	0.030	15.197
1993	0.153	2.488	6.636	2.160	-	1.594	0.742	0.098	-	13.871
1994	0.140	2.209	7.091	2.785	-	1.695	0.743	0.921	-	15.584
1995	0.132	2.580	6.622	2.823	-	1.729	0.722	0.922	-	15.530
1996	0.125	2.556	6.102	2.396	-	1.540	0.589	1.296	-	14.604
1997	0.119	2.432	5.059	2.223	-	1.077	0.602	0.645	-	12.157
1998	0.103	2.079	4.817	2.156	-	0.920	0.700	1.037	-	11.812
1999	0.100	1.787	4.697	1.968	-	0.794	0.645	0.914	-	10.905
2000	0.092	1.742	4.822	1.894	0.002	0.638	0.637	0.893	-	10.720
2001	0.085	1.620	5.353	2.032	0.001	0.609	0.574	1.222	-	11.497
2002	0.079	1.527	5.510	1.959	0.046	0.477	0.666	1.018	-	11.284
2003	0.076	1.440	4.323	1.497	0.911	0.425	0.537	0.849	-	10.059
2004	0.073	1.315	4.018	1.278	0.911	0.402	0.438	0.657	-	9.092
2005	0.037	1.169	3.653	1.132	0.911	0.365	0.402	0.584	-	8.252
2006	0.037	1.059	3.287	1.023	0.911	0.329	0.365	0.548	-	7.558
2007	0.037	0.950	2.922	0.913	0.911	0.292	0.329	0.475	-	6.828
2008	-	0.840	2.557	0.804	0.804	0.256	0.292	0.402	-	5.954
2009	-	0.767	2.192	0.731	0.438	0.219	0.256	0.365	-	4.967
2010	-	0.694	1.826	0.620	0.073	0.178	0.221	0.304	-	3.917
2011	-	0.584	1.461	0.509	-	0.139	0.187	0.243	-	3.123
2012	-	0.475	1.096	0.398	-	0.099	0.153	0.182	-	2.402
2013	-	0.365	0.731	0.287	-	0.060	0.119	0.120	-	1.681
2014	-	0.256	0.365	0.176	-	0.020	0.084	0.059	-	0.961
2015	-	0.146	-	0.065	-	-	0.050	-	-	0.261
2016	-	0.037	-	-	-	-	0.016	-	-	0.052
2017	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-

Cook Inlet (Millions of Barrels per Year)



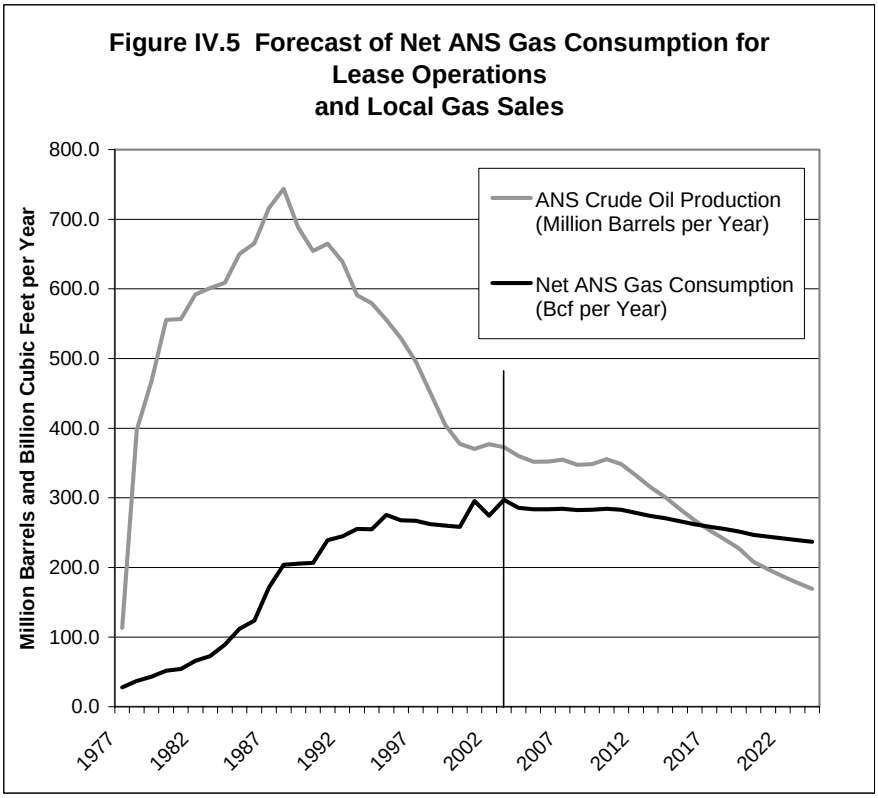
Notes (from previous page):

[1] Forecast based on DNR field-by-field assessment of hisitoric production supplemented with industry outlook, where available. Forecasts beyond 2012 are based on exponential smoothling model. Figure IV.4 corresponds to Table IV.8.

Source: Historic data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports). Forecast prepared by Alaska DNR.

North Slope

Year	Net Gas Consumption on the North Slope (Bcf per Year)
2004	285.6
2005	283.5
2006	283.6
2007	284.3
2008	282.4
2009	282.6
2010	284.4
2011	282.7
2012	278.5
2013	274.1
2014	270.5
2015	266.2
2016	262.0
2017	258.5
2018	255.1
2019	251.8
2020	246.9
2021	244.1
2022	241.6
2023	239.2
2024	237.0
2025	235.0



Notes: Net ANS Gas consumption refers to gas produced for lease operations and for local sales to North Slope utilities and pipelines. Most gas produced is re-injected into the field for enhanced oil recovery and recycling. Historic quantities of injected gas are shown in Table IV.5. Gas injection is expected to remain fairly constant at about 8 Bcf per day for the foreseeable future. Many factors influence the quantity of gas used for lease operations, including demand for power, oil field compression and pipeline pump stations. New field and satellite development will, to some extent, offset the decline in gas used for lease operations and pipelines in mature fields. Also, many North Slope fields are "gas constrained" meaning that oil production is limited by gas handling capacity.

The forecast of net ANS gas consumption is based on an ordinary least squares regression of the historic relationship between net ANS gas consumption and ANS crude oil production, taking into account major additions to gas handling capacity in 1990 (GHX1) and 1995 (GHX2). Detailed estimation results are available on request.

Cook Inlet (Billion Cubic Feet per Year)

	Beluga River[1]	McArthur River (TBU)[2]	North Cook Inlet[3]	Swanson River[4]	Kenai[5]	All Other[6]	Under-Developed[7]	TOTAL NET
1958	-	-	-	0.0	-	-	-	0.0
1959	-	-	-	0.0	-	-	-	0.0
1960	-	-	-	-	-	-	-	-
1961	-	-	-	1.3	0.2	-	-	1.5
1962	-	-	-	1.8	1.5	0.0	-	3.3
1963	0.0	-	-	1.2	3.1	0.0	-	4.3
1964	0.1	-	-	1.6	4.5	0.1	-	6.2
1965	-	-	-	1.1	6.0	0.2	-	7.3
1966	-	-	-	-	33.4	1.5	-	12.4
1967	0.2	0.2	-	-	39.6	9.0	-	24.7
1968	2.0	6.2	-	-	46.0	20.2	-	41.5
1969	3.0	14.2	7.9	-	59.3	22.3	-	80.3
1970	3.6	19.7	40.9	-	80.6	23.1	-	145.2
1971	4.1	19.3	45.0	-	72.2	22.4	-	155.7
1972	4.1	19.7	41.6	-	76.0	15.8	-	148.5
1973	4.9	19.1	42.7	-	71.3	13.1	-	137.8
1974	5.6	19.6	44.2	-	68.5	11.0	-	143.0
1975	7.0	21.5	45.6	-	77.2	10.6	-	154.6
1976	11.2	19.0	45.1	-	79.5	10.3	-	153.3
1977	13.4	19.7	47.2	-	81.9	10.8	-	161.6
1978	14.3	18.6	46.8	-	97.3	9.8	-	179.1
1979	17.0	16.6	49.4	-	97.0	8.6	-	184.7
1980	17.0	15.6	41.5	-	98.8	8.1	-	179.3
1981	17.2	15.2	49.5	-	105.8	7.7	-	192.9
1982	18.7	16.2	45.4	-	115.9	7.3	-	196.1
1983	18.1	14.4	47.9	2.2	113.0	15.2	-	210.7
1984	19.8	15.1	47.0	3.0	110.1	16.7	-	211.7
1985	22.6	10.7	45.8	3.1	115.8	18.9	-	216.9
1986	25.4	13.6	43.8	1.5	82.5	24.6	-	191.3
1987	24.0	13.3	42.9	(3.0)	90.0	22.1	-	189.3
1988	25.6	16.7	45.0	2.9	76.3	30.2	-	196.6
1989	30.1	31.0	45.3	(3.7)	65.7	30.0	-	198.4
1990	39.5	51.5	45.0	(1.6)	38.4	32.7	-	205.5
1991	38.5	61.2	44.7	(0.1)	25.6	33.2	-	203.1
1992	36.5	70.1	44.4	(0.2)	24.2	29.4	-	204.5
1993	31.7	62.5	45.5	4.6	23.8	32.3	-	200.5
1994	34.2	50.0	52.7	27.3	18.9	31.0	-	214.0
1995	35.6	54.9	53.5	28.7	16.5	25.2	-	214.5
1996	36.9	67.3	56.0	33.3	13.3	16.2	-	223.0
1997	35.0	66.8	52.5	28.7	12.7	19.0	-	214.7
1998	33.4	73.8	54.0	25.8	9.7	18.2	-	215.0
1999	36.0	69.0	51.6	29.8	9.9	16.3	-	212.6
2000	38.7	65.0	52.8	29.7	12.8	16.7	-	215.8
2001	41.8	62.3	55.5	22.0	20.0	18.1	-	219.7
2002	44.0	51.5	54.6	12.8	22.2	24.9	0.0	210.0
2003	56.3	39.2	47.9	9.3	28.6	23.6	3.0	208.0
2004	50.0	35.3	47.9	6.2	28.6	33.0	18.0	219.1
2005	50.0	29.1	45.5	3.2	28.6	31.9	24.0	212.3
2006	50.0	24.0	43.2	0.2	24.3	29.5	31.0	202.3
2007	50.0	19.8	41.1	-	20.7	28.4	30.0	190.0
2008	41.3	16.3	39.0	-	17.6	22.3	28.0	164.5
2009	34.0	13.5	37.1	-	14.9	18.2	25.0	142.7
2010	28.1	9.4	35.2	-	12.7	13.9	23.0	122.4
2011	23.2	6.6	33.5	-	10.8	9.8	21.0	104.8
2012	19.1	4.6	31.8	-	9.2	8.6	19.0	92.3
2013	15.8	3.2	30.2	-	7.8	8.5	17.0	82.5
2014	13.0	2.3	28.7	-	6.6	7.4	15.0	73.0
2015	10.7	1.6	27.3	-	-	7.4	14.0	61.0
2016	8.9	1.1	25.9	-	-	6.4	13.0	55.2
2017	7.3	0.8	24.6	-	-	6.3	12.0	51.0
2018	6.0	0.5	23.4	-	-	4.0	11.0	44.9
2019	5.0	-	22.2	-	-	3.0	10.0	40.2
2020	4.1	-	21.1	-	-	-	9.0	34.2
2021	3.4	-	20.0	-	-	-	8.0	31.4
2022	2.8	-	19.0	-	-	-	6.0	27.8

Notes:

[1] Production assumed to decline at 9.2% per year after 2009.

[2] Exponential decline after 2007, based on actual data 1998-2001 and DNR estimates for 2002-2007.

[3] DNR estimate; decline rate of 11.6% after 2007.

[4] Net gas injections reported for Swanson River 1966-82.

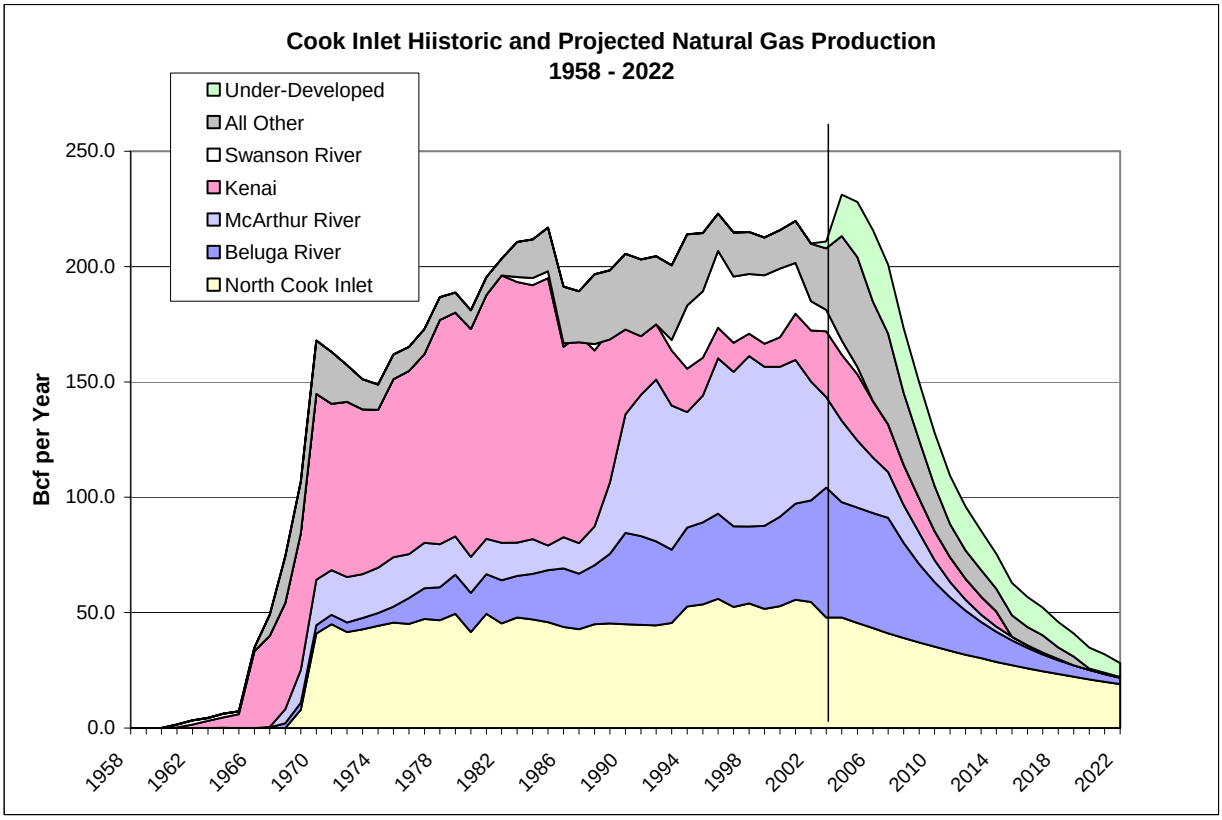
[5] Kenai includes Sterling #3, 4, 5.1, 5.2, and 6 Pools, Beluga Undefined, and Tyonek.

[6] All Other includes Beaver Creek, Cannery Loop, Granite Point, Ivan River, Lewis River, Lone Creek, MGS, Nicolai Creek, North Trading Bay, Redoubt, Sterling, Trading Bay, West Foreland, West Fork, West McArtur River and Wolf Lake.

[7] DNR estimates based primarily on gas prospectivity in the Ninilchik, Kasilof, Deep Creek, and Nikolaevsk exploration units and other exploration areas on the Kenai Peninsula.

Source of Historic Data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", Monthly Reports. Forecast prepared by DNR based on reasonable assumptions about field decline rates and zero reserves appreciation beyond existing proven and undeveloped rerserves.

Cook Inlet (Billion Cubic Feet per Year)



Note:
Figure IV.6 corresponds to Table IV.9.

Cook Inlet (Billion Cubic Feet per Year)

Figure IV.7 Cook Inlet Natural Gas Consumption by Major Group, 1971-2003

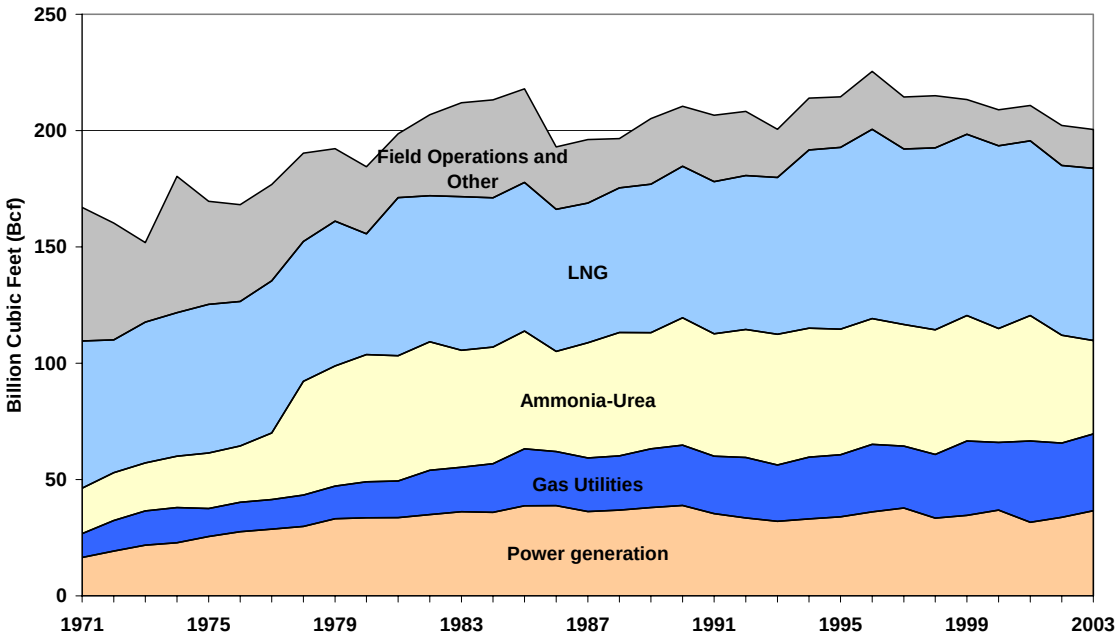


Table IV.10 Cook Inlet Natural Gas Consumption by Major Group, 1990-2003

Billions of Cublic Feet Per Year

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Average 1999-2003
Power Generation	38.9	35.3	33.5	32.0	33.0	34.0	36.1	37.7	33.4	34.6	36.8	31.6	33.7	36.6	**34.7**
Gas Utilities	25.9	24.7	25.9	24.2	26.6	26.7	29.0	26.6	27.4	32.0	29.1	34.9	32.0	33.0	**32.2**
LNG	65.1	65.4	66.2	67.3	76.7	78.1	81.4	75.4	78.1	78.0	78.5	75.2	73.0	74.0	**75.7**
Ammonia-Urea	54.8	52.6	55.0	56.2	55.4	54.0	54.0	52.3	53.6	53.9	49.0	53.9	46.3	40.2	**48.7**
Field Ops and Other	25.8	28.6	27.6	20.7	22.3	21.6	24.8	22.4	22.5	14.9	15.5	15.2	17.2	16.6	**15.9**
	210.4	206.6	208.2	200.5	214.0	214.5	225.4	214.5	215.0	213.4	208.9	210.8	202.2	200.4	**207.1**

Percent of the Total in Each Year (%)

Power generation	18.5	17.1	16.1	16.0	15.4	15.8	16.0	17.6	15.5	16.2	17.6	15.0	16.7	18.3	**16.7**
Gas Utilities	12.3	12.0	12.5	12.1	12.4	12.5	12.9	12.4	12.8	15.0	13.9	16.6	15.8	16.5	**15.5**
LNG	31.0	31.7	31.8	33.6	35.8	36.4	36.1	35.1	36.3	36.5	37.6	35.7	36.1	36.9	**36.6**
Ammonia-Urea	26.0	25.5	26.4	28.0	25.9	25.2	24.0	24.4	24.9	25.3	23.4	25.6	22.9	20.1	**23.5**
Field Ops and Other	12.3	13.8	13.2	10.3	10.4	10.1	11.0	10.4	10.4	7.0	7.4	7.2	8.5	8.3	**7.7**
	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	**100.0**

Section Five

Royalty Production and Revenue

Introduction

The State of Alaska receives a royalty of approximately 12.5 percent of the oil and gas produced from its leases. The state may take its share of oil production "in-kind" or "in-value." When the State takes its royalty share in-kind (RIK), it assumes possession of the oil or gas. The commissioner of Natural Resources may sell the RIK oil or gas in a competitive auction or through a non-competitive sale negotiated with a single buyer. When the state takes its royalty in-value (RIV), the state's lessees who produce the oil or gas, market the State's share along with their own share of production. The lessees remit cash payments on a monthly basis for the state's RIV share.

Over the last 30 years the state has taken about one-half of its royalty oil as RIK.[1] The State has sold nearly 800 million barrels of RIK oil during this time, most of it in-state. These in-state sales provided an important stimulus to the Alaska's refining industry by providing long-term supplies of oil to each of the state's four refineries. Over the years, State RIK sales fueled many controversies and policy debates over the appropriate use of the state's natural resources.

Cook Inlet

In 1969 the commissioner of Natural Resources negotiated a sale of 100 percent of the State's royalty from Cook Inlet to the Alaska Oil and Refining Company. Within months of signing the contract Alaska Oil and Refining Company merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to Chevron's refinery, built in 1964. Between 1969 and 1985 the state sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980, the production decline in the Cook Inlet prompted Tesoro to negotiate the first of several sales contracts with the state for supplies of RIK oil from the North Slope. By the end of 1985 Tesoro had replaced its Cook Inlet RIK volumes with supplies of RIK from the North Slope.

In 1987 the state began to export Cook Inlet RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the West Side of the Cook Inlet after the federal government exempted Cook Inlet production from export administration regulations. The state sold 97 percent of the royalty production from the McArthur River, Trading Bay, North Trading Bay, and Granite Point fields in a series of one-year competitive auctions. In 1991 deliveries under the last Chinese Petroleum contract were halted under force majeure following the December 1989 eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since (See Table V.8.).

[1] The state also sold 10.4 Bcf of RIK gas in a contract to Alaska Pipeline Company (Enstar) from 1977 through 1984 from Cook Inlet royalty production. In a bid to encourage development of the gas resource in Prudhoe Bay, the state entered 20-year contracts in January 1977 to supply El Paso Natural Gas Co., Tenneco Alaska, Inc. and Southern Natural Gas Co. with 25%, 50%, and 25%, respectively, of Prudhoe Bay Unit RIK gas. The contracts terminated in May 1978 when the proposed El Paso Trans-Alaska Gas Pipeline did not receive Federal certification.

North Slope

Over the past 25 years, the state has held nine RIK sales involving portions of its Alaska North Slope (ANS) royalty oil production. These sales are summarized in Table V.7 and Figure V.3. In 1976, the State signed a six-year contract with Golden Valley Electric Association (GVEA), the electric utility in Fairbanks, to sell approximately 3,300 barrels of ANS crude oil per day as turbine fuel. GVEA did not exercise its option to take RIK until 1981 and it traded these volumes with Mapco (now Williams Alaska) in exchange for refined fuel. The state subsequently sold RIK ANS to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

In 1978 the State contracted with Earth Resources Company of Alaska, predecessor to Mapco Alaska and now Williams Alaska Petroleum Company, to supply 15 percent of Prudhoe Bay RIK oil production less the quantity dedicated to GVEA. This 25-year contract expires in December 2003. Williams receives a maximum of 35,000 barrels per day of RIK oil produced from the Prudhoe Bay Unit under this contract and has since supplemented this supply with new agreements for another 28,000 barrels per day. Williams is now the only purchaser of State RIK ANS crude oil. When the two Williams' contracts expire at the end of 2003, the royalty oil production available for new sales will rise to 120,000 barrels per day. Available royalty will decline thereafter at about 5 percent per year.

As mentioned above, Tesoro has been an important North Slope RIK customer. Tesoro negotiated and bid for several contracts that supplied it with RIK supplies from 1980 to 1998. Chevron was another big purchaser of North Slope RIK for oil supplied to its Nikiski refinery from 1980 through 1991, when it finally shut down its Nikiski refinery. In one of these contracts Chevron took RIK barrels from Tesoro in exchange. Petro Star Inc. purchased North Slope RIK from 1986 through 1991 for its new refinery at North Pole. In 1992 Petro Star negotiated a 10-year contract with the state for a supply of RIK from the Kuparuk River Unit. With this contract in hand, Petro Star was able to build the state's newest refinery in Valdez. As it happened, Petro Star elected to take no oil under this contract and the contract expired automatically nine months after it had been signed.

The state also held competitive auctions of RIK oil during the early 1980s as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several outside refineries. Many of these buyers were also ANS producers. About 46 million barrels of Alaska North Slope RIK crude oil were sold in these auctions but the program was interrupted after the general collapse of oil prices in the mid 1980s. In January 2000, the Division of Oil and Gas published a *Notice of Interest in Sale of State Royalty Oil*. The response to this notice by prospective RIK purchasers prompted the division to plan for a competitive bid auction for volumes of RIK oil produced from several North Slope fields. The sale was subsequently held in August 2000 but no bids were offered.

Royalty-in-Kind Policy

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated controversy and debate in the state. Several issues arose as the RIK program evolved. Is the state better off negotiating sales one-on-one or auctioning RIK through competitive tenders? How much public input should be encouraged? Should the state subsidize the local refining industry through price breaks? What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Furthermore, the legislature established the Alaska Royalty Oil and Gas Development Board (Royalty Board) under AS 38.06 to oversee the department's RIK program. Regulations under Title 11, Chapters 3 and 26 govern the actual disposition of royalty and the sale of RIK. (See http://www.legis.state.ak.us/folhome.htm for more information).

The rules that govern the sale of RIK may be reduced to a few principles.

- Any disposition of the state's royalty must be in the state's best interest. The state should sell its royalty rather than take it in-value as long as the best interests of the state are served.
- The state must receive a price for its RIK that is at least as much as it receives when the state takes its royalty in-value.
- Under certain circumstances, the state may sell its oil in a negotiated sale, but competitive sales are preferred.
- Although the price of RIK must equal or exceed the price of RIV, a review of each sale must consider economic, social, and environmental effects. In this way, benefits may be attributed to the sale of RIK to local refineries that would not be generated by sales to outside purchases.
- The public is a part of the process. Depending on the terms of the sale, the commissioner will publish best interest findings and solicit comments on the sale from the public.
- The Royalty Board must be notified of any disposition of RIK. For supply contracts for more than one year, the Royalty Board must evaluate the economic, social, and environmental effects of the sale, convene a public hearing, and recommend approval of the sale to the legislature.
- The legislature approves long-term contracts by enacting legislation.

Table V.1 Recent Royalty Oil Production and Revenues

North Slope, 1996-2003

	Badami	Colville River Unit	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Northstar	Prudhoe Bay Unit RIV	Prudhoe Bay Unit RIK	TOTAL Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousands of Barrels)										
1996	-	-	3,679.6	11,366.3	1,800.6	-	19,133.3	25,081.1	44,214.3	61,060.8
1997	-	-	3,324.4	10,978.3	2,657.0	-	18,399.6	26,139.6	44,539.2	61,498.8
1998	106.1	-	2,692.5	10,886.2	2,833.4	-	11,810.5	27,981.6	39,792.1	56,310.2
1999	179.2	1.3	2,263.3	10,822.0	2,699.2	-	15,508.5	19,070.7	34,579.2	50,544.1
2000	144.6	196.6	1,943.1	9,897.9	2,613.9	-	13,053.5	19,290.3	32,343.8	47,140.0
2001	104.0	2,785.5	1,696.9	9,076.4	2,687.9	212.9	13,643.5	15,187.0	28,830.6	45,394.3
2002	87.0	3,403.4	1,483.5	8,944.0	2,570.7	4,009.3	11,789.3	15,509.6	27,298.9	47,796.8
2003	42.1	3,777.1	1,535.1	8,916.0	2,569.5	5,236.7	5,480.7	20,638.8	26,119.5	48,196.7
Revenues (Thousands of Dollars)										
1996	-	-	$57,988	$188,462	$28,404	-	$296,101	$436,377	$732,478	$1,007,332
1997	-	-	$42,866	$150,137	$33,777	-	$242,341	$383,701	$626,042	$852,822
1998	-	-	$18,147	$82,772	$18,608	-	$69,281	$227,032	$296,313	$415,841
1999	-	$57	$26,461	$136,802	$31,596	-	$170,204	$259,246	$429,450	$624,366
2000	$2,612	$4,539	$42,350	$220,539	$56,730	-	$275,928	$461,464	$737,392	$1,064,162
2001	$1,051	$47,972	$31,796	$160,694	$47,356	$1,584	$236,464	$279,804	$516,268	$806,722
2002	$108	$62,818	$27,128	$173,379	$48,818	$75,797	$201,726	$320,378	$522,104	$910,151
2003	$46	$89,684	$35,753	$211,369	$61,255	$123,753	$114,558	$507,952	$622,509	$1,144,385

Revenues include principal and interest from revisions and settlements in the year received.

Cook Inlet & Statewide, 1996-2003

	Granite Point Field	South Granite Point Unit	Cannery Loop Field	North Middle Ground Shoal	Middle Ground Shoal	South Middle Ground Shoal	Trading Bay Field	Trading Bay Unit	West McArthur Unit	Redoubt Unit	Undefined	**TOTAL Cook Inlet**	**TOTAL STATE**
Production (Thousands of Barrels)													
1996	320.3	-	0.0	50.6	216.5	32.5	73.6	762.7	162.0	-	-	1,618.2	62,679.0
1997	303.5	-	-	42.0	150.6	26.8	75.1	632.4	80.6	-	-	1,311.0	62,809.8
1998	259.8	-	-	44.7	196.0	28.8	87.1	602.4	116.2	-	-	1,335.0	57,645.2
1999	172.4	51.0	-	38.2	181.9	24.6	82.7	587.2	114.3	-	-	1,252.2	51,796.3
2000	119.2	98.5	-	43.5	170.5	22.8	79.6	602.8	111.6	-	-	1,248.6	48,388.5
2001	109.3	92.9	-	39.7	194.4	19.8	72.3	671.1	152.9	-	-	1,352.4	46,746.7
2002	105.2	86.1	-	27.1	197.1	20.8	76.0	704.3	120.3	2.3	-	1,339.2	49,136.0
2003	98.8	79.8	-	11.8	175.4	-	68.7	538.6	105.9	45.5	1.0	1,125.4	49,322.1
Revenues (Thousands of Dollars)													
1996	$5,825	-	-$6	$1,000	$4,266	$613	$1,188	$13,330	$2,257	-	-	$28,474	$1,035,805
1997	$5,175	-	-	$764	$3,655	$490	$1,192	$10,561	$1,795	-	-	$23,633	$876,456
1998	$2,813	-	-	$544	$2,244	$346	$853	$5,902	$1,107	-	-	$13,809	$429,650
1999	$2,090	$1,388	-	$662	$3,073	$406	$1,261	$8,917	$1,583	-	-	$19,380	$643,746
2000	$4,201	$3,840	-	$1,491	$4,647	$821	$2,632	$17,073	$2,790	-	-	$37,495	$1,101,657
2001	$2,515	$2,051	-	$959	$4,338	$476	$1,522	$13,908	$2,941	-	-	$28,710	$835,432
2002	$2,337	$1,850	-	$619	$5,428	$494	$1,609	$14,992	$2,680	$54	-	$30,062	$940,214
2003	$2,633	$2,249	-	$349	$5,103	-	$1,876	$14,693	$2,736	$1,140	$19	$30,798	$1,175,183

Revenues include principal and interest from revisions and settlements in the year received.

Table V.2 Recent Royalty Oil Production by Lessee

North Slope

	Production (Thousands of Barrels)							
	1996	1997	1998	1999	2000	2001	2002	2003
Amerada Hess	-	-	-	-	-	-	-	-
Amoco	360	297	237	199	119	-	-	-
Anadarko	-	-	-	0	43	613	749	830,967
Arco	12,394	11,120	9,522	10,729	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	-	191
BPAPC	-	-	-	-	-	-	-	165,163
BP	18,375	16,683	13,595	14,233	11,869	11,075	14,546	13,897,892
Chevron	116	99	64	91	77	81	117	66,186
CIRI	36	30	1	-	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	-	11,244	9,250,243
DOYON	7	6	5	4	4	3	3	2,707
Exxon	6,364	5,571	3,563	4,815	-	-	-	-
ExxonMobil	-	-	-	-	4,596	5,287	-	-
ExxonMobil AK Prod	-	-	-	-	-	-	4,282	1,917,792
Forcenergy/Forest Oil	-	5	3	4	2	2	2	861
L L & E	5	-	-	-	-	-	-	-
Mapco 1978 Contract	13,037	12,652	11,148	12,442	12,718	12,522	12,167	12,582,787
Mapco 1997 Contract	-	466	4,451	-	-	-	-	-
Marathon	6	-	-	-	-	-	-	-
Mobil	280	237	155	195	-	-	-	-
NANA	22	18	14	12	11	8	8	8,121
Oxy	155	208	224	212	189	-	-	-
Petrofina	-	-	32	54	43	31	-	-
Phillips	231	190	113	151	10,201	12,482	-	-
Phillips Alpine Alaska	-	-	-	-	-	-	749	830,967
Pioneer	-	-	-	-	-	-	-	447
Shell	7	-	-	-	-	-	-	-
Tesoro	14,346	13,022	11,498	-	-	-	-	-
Texaco	63	52	31	41	35	38	18	-
TotalFina ELF	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	-	-	-	-	-
Unocal	976	842	771	732	659	587	570	586,290
Williams 1998 Contract	-	-	884	6,628	6,572	2,665	3,342	8,056,038
North Slope TOTAL	66,779	61,499	56,312	50,544	47,140	45,394	47,797	48,196,653

Cook Inlet

	Production (Thousands of Barrels)							
	1996	1997	1998	1999	2000	2001	2002	2003
Conoco Phillips AK	-	-	-	-	-	-	-	672
Cross Timbers/XTO	-	-	-	182	170	194	197	175,357
Devon	-	-	-	-	-	-	-	48
Forcenergy/Forest Oil	-	377	436	425	428	495	488	435,844
Marathon	386	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prc	100	110	91	76	74	70	65	59,843
Shell	216	151	196	-	-	-	-	-
Stewart	162	30	-	-	-	-		-
Unocal	754	643	612	569	576	593	590	453,633
Cook Inlet TOTAL	1,618	1,311	1,335	1,252	1,249	1,352	1,339	1,125,398

Revenues include principal and interest from revisions and settlements in the year received.

Table V.3 Recent Royalty Oil Revenue by Lessee

North Slope

	Revenues (Thousands of Dollars)							
	1996	1997	1998	1999	2000	2001	2002	2003
Amerada Hess	-$118,215	$34,097	-	-	-	-	-	-
Amoco	$5,403	$3,674	$1,556	$2,404	$2,562	-$0	-	-
Anadarko	-	-	-	$12	$982	$10,374	$14,180	$20,057,061
Arco	$190,182	$155,281	$72,786	$135,879	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	-	$4,481
BPAPC	-	-	-	-	-	-	-	$3,934,319
BP	$256,839	$216,022	$85,232	$158,955	$249,682	$208,250	$267,287	$325,241,292
Chevron	$1,712	$1,274	$368	$1,044	$1,608	$1,422	$2,070	$1,437,347
CIRI	$518	$423	$12	-	-	-	$1,549	$0
ConocoPhillips AK	-	-	-	-	-	-	$211,239	$214,805,796
DOYON	$103	$83	$41	$39	$82	$54	$44	$63,940
Exxon	$90,516	$71,707	$19,733	$52,342	-	-	-	-
ExxonMobil	-	-	-	-	$98,415	$83,945	-	-
ExxonMobil AK Prod	-	-	-	-	-	-	$69,780	$37,737,447
Forcenergy/Forest Oil	-	$63	$17	$43	$50	$38	$37	$17,549
L L & E	$68	-	-	-	-	-	-	-
Mapco 1978 Contract	$207,138	$185,000	$90,752	$166,427	$304,389	$223,123	$247,246	$316,071,951
Mapco 1997 Contract	-	$6,032	$38,590	-$60	$90	$1,075	-	-
Marathon	$84	$1	-	-	-	-	-	-
Mobil	$4,035	$3,026	$851	$2,166	-	-	-	-
NANA	$310	$255	$122	$120	$220	$163	$131	$220,580
Oxy	$2,248	$2,778	$1,533	$2,626	$4,290	-	-	-
Petrofina	-	-	$168	$616	$807	$284	-	-
Phillips	$3,175	$2,377	$752	$1,379	$228,306	$211,865	-	-
Phillips Alpine Alaska	-	-	-	-	-	-	$13,718	$19,628,298
Pioneer	-	-	-	-	-	-	-	$10,455
Shell	$102	-$5	-	-	-	-	-	-
Tesoro	$229,239	$192,669	$92,288	$191	-$623	$1,632	$887	-
Texaco	$880	$664	$149	$398	$842	$653	$270	-
TotalFina ELF	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	$12	-	-	-	-
Unocal	$14,896	$11,463	$6,013	$9,078	$14,851	$9,868	$10,858	$13,264,738
Williams 1998 Contract	-	-	$5,402	$92,688	$157,608	$53,975	$72,245	$196,991,285
North Slope TOTAL	$1,007,332	$852,822	$416,365	$626,358	$1,064,162	$806,722	$911,540	$1,149,486,540

Cook Inlet

	Revenues (Thousands of Dollars)							
	1996	1997	1998	1999	2000	2001	2002	2003
Conoco Phillips AK	-	-	-	-	-	-	-	13,091
Cross Timbers/XTO	-	-	-	3,073	4,647	4,338	5,428	5,103,097
Devon	-	-	-	-	-	-	-	935
Forcenergy/Forest Oil	-	6,166	4,209	6,296	10,950	9,831	10,522	11,521,144
Marathon	6,620	-7	-	-	-	-	-	-
Mobil/Exxon Mobil AK Pro	1,810	1,882	1,094	1,165	1,824	1,525	1,348	1,691,541
Shell	4,266	3,655	2,244	-	-	-	-	-
Stewart	2,257	1,104	-	-	-	-	-	-
Unocal	13,521	10,834	6,262	8,846	20,074	13,016	12,764	12,470,786
Cook Inlet TOTAL	28,474	23,633	13,809	19,380	37,495	28,710	30,062	30,800,593

Revenues include principal and interest from revisions and settlements in the year received.

Table V.4 Recent Royalty Gas Production and Revenues

North Slope, 1996-2003

	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousand Cubic Feet)					
1996	32,446	107,807	9,466	1,467,794	1,617,513
1997	35,605	90,487	26,034	1,337,301	1,489,427
1998	36,255	79,552	27,156	1,178,761	1,321,724
1999	168,919	78,783	27,611	1,092,217	1,367,530
2000	31,785	135,929	27,436	1,061,761	1,256,911
2001	30,780	98,806	28,978	1,341,442	1,500,006
2002	32,108	83,021	29,718	3,711,292	3,856,140
2003	33,191	79,039	28,844	5,707,165	5,848,240
Revenues					
1996	$30,497	$96,452	$29,676	$1,318,431	$1,475,056
1997	$31,402	$63,482	$28,326	$1,154,595	$1,277,804
1998	$27,554	$32,473	$23,723	$949,674	$1,033,424
1999	$150,373	$50,763	$26,108	$937,602	$1,164,845
2000	$39,659	$160,539	$33,872	$1,156,060	$1,390,130
2001	$33,017	$119,259	$31,606	$1,114,358	$1,298,240
2002	$36,574	$79,070	$34,277	$3,591,859	$3,741,781
2003	$45,319	$91,406	$39,583	$6,508,328	$6,684,636

Revenues include principal and interest from revisions and settlements in the year received.

Cook Inlet, 1996-2003

	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	Nicolai Creek	North Middle Ground Shoal Unit	Middle Ground Shoal
Production (Thousand Cubic Feet)										
1996	2,777,105	122,528	-	109,798	1,167,827	159,084	11,389	-	403	996
1997	2,628,297	186,477	-	141,763	935,228	140,655	7,057	-	17,965	-
1998	2,508,785	163,775	1,127	162,690	800,046	111,751	11,959	-	131,092	-
1999	2,704,980	167,759	28,102	67,573	631,597	111,459	29,916	-	246,030	-
2000	2,913,658	236,492	55,787	73,754	461,437	149,187	16,232	-	72,167	-
2001	3,143,083	318,033	5,491	59,671	667,307	234,786	26,852	32,297	52,739	-
2002	3,313,302	286,118	3,859	34,936	756,028	233,375	111,535	31,792	14,404	
2003	4,236,316	390,962	2,042	10,580	432,649	323,139	71,284	8,464	11,612	-
Revenues										
1996	$3,942,906	$205,833	-	$180,076	$1,995,187	$250,307	$19,865	-	$14,576	$613
1997	$4,598,164	$325,190	-	$191,592	$1,318,780	$249,102	$9,943	-	$23,979	-
1998	$4,264,931	$231,820	$1,353	$221,096	$1,070,859	$156,838	$15,585	-	$160,470	-
1999	$3,782,832	$271,607	$30,115	$82,135	$757,916	$294,223	$35,899	-	$300,841	-
2000	$4,657,037	$482,859	$58,151	$215,085	$5,338,631	$298,388	$508,075	-	$808,397	-
2001	$6,947,145	$1,216,499	$5,995	$82,050	$932,562	$476,303	$37,703	$61,686	$88,702	-
2002	$7,586,256	$748,357	$4,218	$50,088	$1,057,045	$453,777	$160,290	$17,840	$20,846	
2003	$9,478,535	$835,807	$6,023	$178,888	$2,903,601	$701,376	$334,949	$17,006	$59,853	-

	South Middle Ground Shoal	North Cook Inlet Unit	Pretty Creek Unit	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	Redoubt Unit	Ninilchik Unit	**TOTAL Cook Inlet**	**TOTAL State**
Production (Thousand Cubic Feet)													
1996	489	6,910,165	41,347	2,814	558	57	44,183	-	7,248,017	-	-	18,596,759	20,214,272
1997	-	6,490,318	53,928	62,872	81	-	30,942	19,031	6,982,452	-	-	17,697,067	19,186,494
1998	-	6,665,243	61,640	85,882	4	-	18,332	-	7,841,950	-	-	18,564,277	19,886,001
1999	-	6,372,036	3,982	28,044	15	-	11,978	-	7,333,019	-	-	17,736,489	19,104,019
2000	-	6,548,758	-	-	4,384	18,632	6,839	-	6,802,700	-	-	17,360,027	18,616,938
2001	-	6,732,002	11,471	-	8,820	-	56	-	6,509,275	-	-	17,801,883	19,301,889
2002		6,537,260	189,692	-	11,655	-	-	-	5,198,621	-	-	16,722,576	20,578,716
2003	-	5,773,799	60,292	-	7,195	11,954	69	-	3,867,554	12,356	289,627	15,509,893	21,358,133
Revenues													
1996	$72	$11,615,706	$69,483	$3,796	$1,514	$77	$31,502	-	$10,286,938	-	-	$28,618,453	$30,093,509
1997	-	$12,054,437	$75,855	$94,178	$140	-	-	$22,797	$10,147,976	-	-	$29,112,134	$30,389,938
1998	-	$8,874,018	$82,099	$118,197	$8	-	$71	-	$10,768,856	-	-	$25,966,200	$26,999,624
1999	-	$8,914,102	$4,778	$31,511	$19	-	$12,836	-	$8,917,539	-	-	$23,436,353	$24,601,199
2000	-	$14,057,602	$678,220	-	$6,825	$25,859	$1,253,836	$1,999	$10,743,014	-	-	$39,133,978	$40,524,108
2001	-	$14,301,074	$18,009	-	$16,076	$5,601	$67	-	$12,636,322	-	-	$36,825,794	$38,124,034
2003	-	$12,159,221	$378,856	-	$16,365	$27,539	$5,031	-	$14,806,030	$15,544	$680,938	$42,605,562	$46,347,343

Revenues include principal and interest from revisions and settlements in the year received.

Table V.5 Recent Royalty Gas Production by Lessee

North Slope

	Production (Thousand Cubic Feet)							
	1996	1997	1998	1999	2000	2001	2002	2003
Arco	387,761	400,895	393,981	412,016	-	-	-	-
BPAPC	-	-	-	-	-	-	-	1,852
BP Exploration	761,862	657,646	560,854	627,551	488,604	735,945	3,134,638	4,985,434
Chevron	17,786	16,561	5,070	-	-	1	2	2
ConocoPhillips AK	-	-	-	-	-	-	461,188	598,612
Exxon	297,260	284,187	264,969	241,821	-	-	-	-
Exxon Mobil/ExxonMobil AK	-	-	-	-	298,217	293,045	260,247	262,275
Forest Oil	-	-	-	-	-	3	-	-
Mobil	101,256	84,433	78,519	74,713	-	-	-	-
NANA	32,446	25,930	-	-	-	-	-	-
Oxy	1,512	1,988	2,134	2,203	1,997	-	-	-
Phillips	17,630	17,786	16,197	9,226	468,093	470,986	-	-
Unocal	-	-	-	-	-	27	65	65
North Slope TOTAL	1,617,513	1,489,427	1,321,724	1,367,530	1,256,911	1,500,007	3,856,140	5,848,240

Cook Inlet

	Production (Thousand Cubic Feet)							
	1996	1997	1998	1999	2000	2001	2002	2003
Arco	930,529	812,591	760,156	902,501	-	-	-	-
Aurora Power	-	-	-	-	-	32,296	31,792	8,464
Chevron	809,536	830,436	843,072	1,026,724	1,002,570	1,303,514	1,459,992	1,697,961
ConocoPhillips AK	-	-	-	-	-	-	1,287,322	1,949,494
Conoco Phillips Co.								5,773,799
Danco	85	-	-	-	-	-	-	-
Forest Oil	-	-	-	-	-	-	-	12,356
Marathon	4,475,074	3,995,784	4,062,765	4,347,695	4,358,280	4,234,315	3,356,118	3,077,325
Mobil/ Exxon Mobil	22,815	50,177	55,372	21,509	52,341	4,118	2,894	1,532
Municipal Light & Power	-	-	905,557	775,755	677,169	617,794	565,988	588,860
Phillips	6,910,165	6,490,318	6,665,243	6,372,036	7,782,678	7,953,777	6,537,260	-
Shell	1,038,035	985,270	-	-	-	-	-	-
Unocal	4,410,520	4,532,490	5,272,111	4,290,269	3,486,988	3,656,068	3,481,210	2,400,102
Cook Inlet TOTAL	18,596,759	17,697,067	18,564,277	17,736,489	17,360,026	17,801,882	16,722,576	15,509,893

Revenues include principal and interest from revisions and settlements in the year received.

Table V.6 Recent Royalty Gas Revenues by Lessee

North Slope

	Revenue							
	1996	1997	1998	1999	2000	2001	2002	2003
Arco	$326,746	$325,488	$297,465	$343,610	-	-	-	-
BPAPC	-	-	-	-	-	-	-	$2,548
BP Exploration	$658,038	$543,435	$451,204	$539,789	$539,435	$593,254	$3,054,036	5,843,625
Chevron	$47,435	$33,157	$7,165	-	-	$19	$5	2
ConocoPhillips AK	-	-	-	-	-	-	$446,181	538,385
Exxon	$229,871	$207,325	$182,809	$185,339	-	-	-	-
Exxon Mobil/ExxonMobil AK	-	-	-	-	$318,417	$264,849	$241,558	300,004
Forest Oil	-	-	-	-	-	-	-	-
Mobil	$168,198	$127,870	$79,937	$86,789	-	-	-	-
NANA	$30,782	$23,282	-	-	-	-	-	-
Oxy	$964	$1,929	$1,887	$1,937	$1,744	-	-	-
Phillips	$13,021	$15,319	$12,957	$7,381	$530,534	$440,117	-	-
Unocal	-	-	-	-	-	-	-	72
North Slope TOTAL	$1,475,056	$1,277,804	$1,033,424	$1,164,845	$1,390,130	$1,298,239	$3,741,781	$6,684,636

Cook Inlet

	Revenue							
	1996	1997	1998	1999	2000	2001	2002	2003
Arco	$1,352,425	$1,411,208	$1,262,404	$1,169,971	-	-		
Aurora Power	-	-	-	-	-	$61,686	$17,840	$17,006
Chevron	$1,073,740	$1,551,102	$1,559,786	$1,605,202	$1,697,968	$3,135,824	$3,739,693	$4,373,045
ConocoPhillips AK	-	-	-	-	-	-	$2,530,071	$3,747,465
Conoco Phillips Co.								$12,159,221
Danco	$799	-	-	-	-	-	-	-
Forest Oil	-	-	-	-	-	-	-	$15,544
Marathon	$6,181,274	$6,061,206	$5,736,683	$5,557,091	$6,795,330	$10,428,942	$7,432,627	$6,777,194
Mobil/ Exxon Mobil	$19,482	$47,489	$55,372	$21,509	-$246	$4,113	$2,867	$1,532
Municipal Light & Power	-	-	$1,442,741	$1,007,659	$1,082,297	$1,415,666	$1,316,493	$1,358,025
Phillips	$11,615,706	$12,054,437	$8,874,018	$8,914,102	$15,934,374	$16,696,729	$12,562,238	-
Shell	$1,517,354	$1,635,854	-	-	-	-	-	-
Unocal	$6,857,672	$6,350,838	$7,035,196	$5,160,819	$13,624,255	$5,082,834	$4,993,051	$14,156,530
Cook Inlet TOTAL	$28,618,453	$29,112,134	$25,966,200	$23,436,353	$39,133,978	$36,825,794	$32,594,879	$42,605,562

Revenues include principal and interest from revisions and settlements in the year received.

Table V.7 and Figure V.1 North Slope Royalty in-Kind Sales

1979-2003 (Barrels per Year)

	Alpetco	Chevron	Williams (Mapco)	Golden Valley Elec Assoc	Tesoro	Petro Star	1st Comp Sale	2nd Comp Sale	Quasi-Comp Sale	ANS TOTAL RIK	ANS TOTAL RIV	ANS TOTAL RIK + RIV
1979	-	-	446,996	-	-	-	-	-	-	446,996	10,584,481	11,031,477
1980	12,020,950	882,414	5,976,024	-	3,427,388	-	-	-	-	22,306,777	47,047,583	69,354,360
1981	26,046,878	859,928	8,808,400	398,051	1,661,385	-	14,046,953	-	-	51,821,595	17,666,128	69,487,723
1982	898,714	-	9,632,099	764,762	36,841	-	1,432,108	-	-	12,764,524	61,136,212	73,900,736
1983	-	11,674,998	11,723,755	1,208,406	5,793,973	-	-	-	-	30,401,132	44,599,235	75,000,367
1984	-	14,053,279	13,093,397	1,870,505	7,531,155	-	-	-	-	36,548,337	39,396,031	75,944,369
1985	-	7,804,392	13,260,754	1,928,544	17,218,912	-	-	22,511,409	1,716,754	64,440,764	16,633,246	81,074,010
1986	-	6,934,482	13,168,483	1,881,232	23,538,192	52,667	-	4,686,801	1,862,051	52,123,907	30,262,661	82,386,568
1987	-	9,330,563	14,094,537	2,013,539	18,404,806	539,575	-	-	-	44,383,020	43,899,311	88,282,331
1988	-	9,315,264	13,814,522	1,981,998	18,307,014	590,832	-	-	-	44,009,630	44,068,971	88,078,602
1989	-	8,611,606	12,529,175	1,784,782	16,387,093	607,468	-	-	-	39,920,122	40,833,646	80,753,768
1990	-	8,099,292	12,735,412	1,670,494	15,368,565	621,220	-	-	-	38,494,983	37,242,490	75,737,473
1991	-	6,290,546	11,183,462	1,670,699	15,336,301	618,247	-	-	-	35,099,255	42,537,362	77,636,617
1992	-	-	6,303,005	801,795	14,412,451	-	-	-	-	21,517,251	60,174,977	81,692,228
1993	-	-	9,086,280	-	9,814,311	-	-	-	-	18,900,591	55,796,583	74,697,174
1994	-	-	11,812,241	-	10,312,487	-	-	-	-	22,124,728	50,657,903	72,782,631
1995	-	-	12,680,470	-	13,703,946	-	-	-	-	26,384,415	43,664,553	70,048,968
1996	-	-	13,037,159	-	14,345,554	-	-	-	-	27,382,712	39,396,515	66,779,227
1997	-	-	13,117,616	-	13,021,937	-	-	-	-	26,139,553	35,359,288	61,498,841
1998	-	-	16,483,827	-	11,497,733	-	-	-	-	27,981,560	28,330,383	56,311,943
1999	-	-	19,070,664	-	-	-	-	-	-	19,070,664	31,473,445	50,544,109
2000	-	-	19,290,297	-	-	-	-	-	-	19,290,297	27,848,612	47,138,909
2001	-	-	15,187,012	-	-	-	-	-	-	15,187,012	30,207,251	45,394,263
2002	-	-	15,509,592	-	-	-	-	-	-	15,509,592	32,287,249	47,796,841
2003	-	-	20,638,824	-	-	-	-	-	-	20,638,824	27,557,829	48,196,653
	38,966,543	83,856,765	312,684,003	17,974,807	230,120,043	3,030,009	15,479,061	27,198,210	3,578,804	732,888,244	938,661,945	1,671,550,190

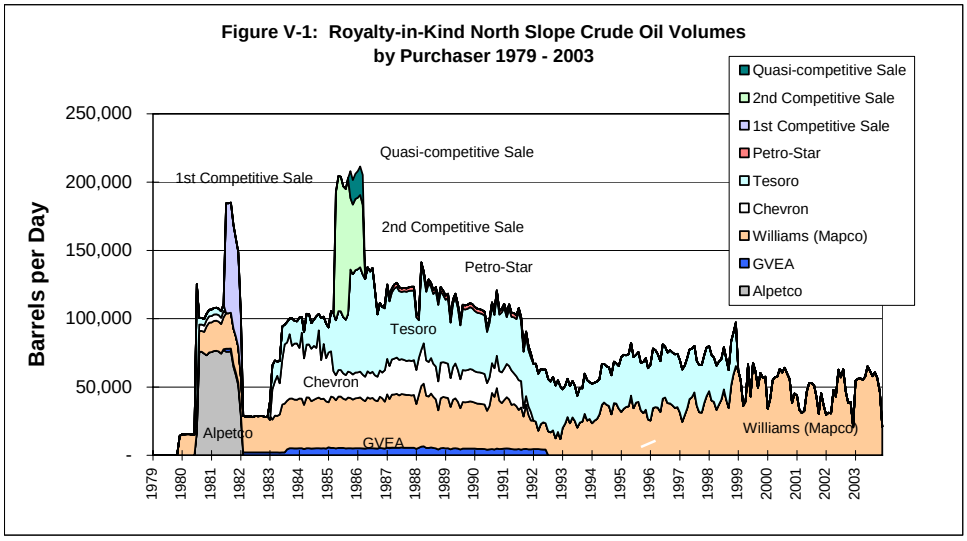


Table V.8 Cook Inlet Royalty in-Kind Sales

1979-2003 (Barrels per Year)

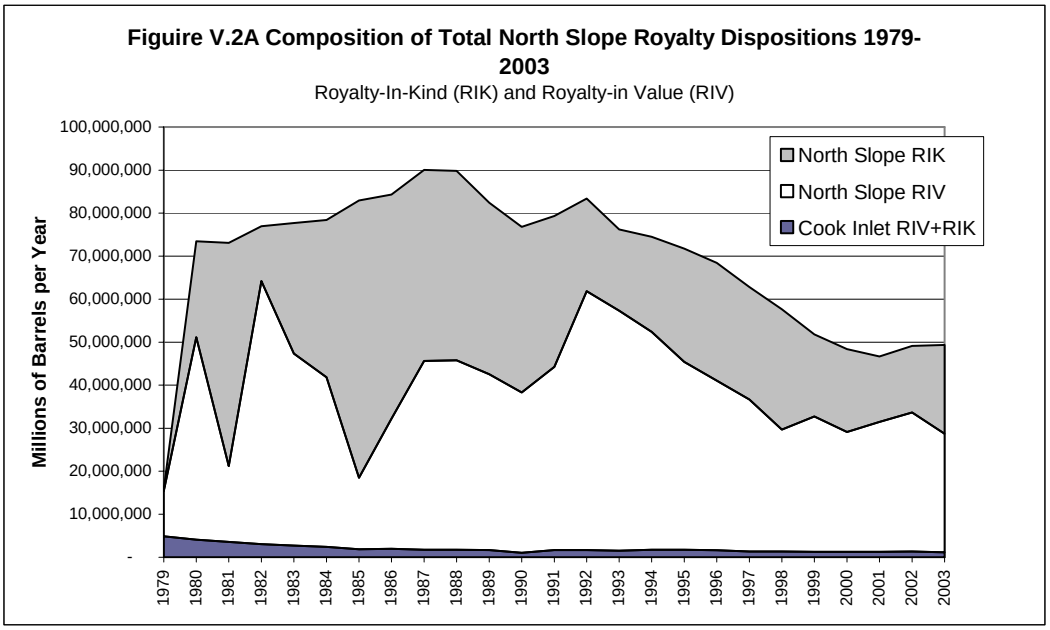
	Tesoro[1]	Chinese Petroleum[2]	CI TOTAL RIK	CI TOTAL RIV	CI TOTAL RIK + RIV	TOTAL RIK	TOTAL RIV	TOTAL RIK + RIV
1979	4,849,631	-	4,849,631	-	4,849,631	5,296,627	10,584,481	15,881,108
1980	4,094,229	-	4,094,229	-	4,094,229	26,401,006	47,047,583	73,448,589
1981	3,560,736	-	3,560,736	-	3,560,736	55,382,331	17,666,128	73,048,459
1982	3,065,159	-	3,065,159	-	3,065,159	15,829,683	61,136,212	76,965,895
1983	2,719,044	-	2,719,044	-	2,719,044	33,120,176	44,599,235	77,719,411
1984	2,431,987	-	2,431,987	-	2,431,987	38,980,324	39,396,031	78,376,356
1985	1,382,740	-	1,382,740	462,245	1,844,985	65,823,504	17,095,491	82,918,995
1986	-	-	-	1,922,102	1,922,102	52,123,907	32,184,763	84,308,671
1987	-	625,099	625,099	1,104,010	1,729,109	45,008,119	45,003,321	90,011,440
1988	-	798,885	798,885	912,193	1,711,078	44,808,515	44,981,164	89,789,680
1989	-	1,274,480	1,274,480	388,888	1,663,368	41,194,602	41,222,534	82,417,136
1990	-	579,337	579,337	480,570	1,059,908	39,074,320	37,723,061	76,797,381
1991	-	330,540	330,540	1,354,524	1,685,064	35,429,795	43,891,886	79,321,681
1992	-	-	-	1,661,526	1,661,526	21,517,251	61,836,503	83,353,754
1993	-	-	-	1,514,651	1,514,651	18,900,591	57,311,234	76,211,825
1994	-	-	-	1,717,759	1,717,759	22,124,728	52,375,662	74,500,390
1995	-	-	-	1,718,805	1,718,805	26,384,415	45,383,358	71,767,773
1996	-	-	-	1,618,158	1,618,158	27,382,712	41,014,673	68,397,385
1997	-	-	-	1,311,001	1,311,001	26,139,553	36,670,289	62,809,842
1998	-	-	-	1,335,030	1,335,030	27,981,560	29,665,413	57,646,973
1999	-	-	-	1,252,231	1,252,231	19,070,664	32,725,676	51,796,340
2000	-	-	-	1,248,564	1,248,564	19,290,297	29,097,175	48,387,473
2001	-	-	-	1,273,518	1,273,518	15,187,012	31,480,769	46,667,780
2002	-	-	-	1,339,178	1,339,178	15,509,592	33,626,427	49,136,019
2003	-	-	-	1,125,398	1,125,398	20,638,824	28,683,226	49,322,051
	22,103,526	3,608,341	25,711,867	23,740,351	49,452,218	758,600,111	962,402,296	1,721,002,407

Notes:

[1] East and west side.

[2] West side export.

North Slope and Cook Inlet



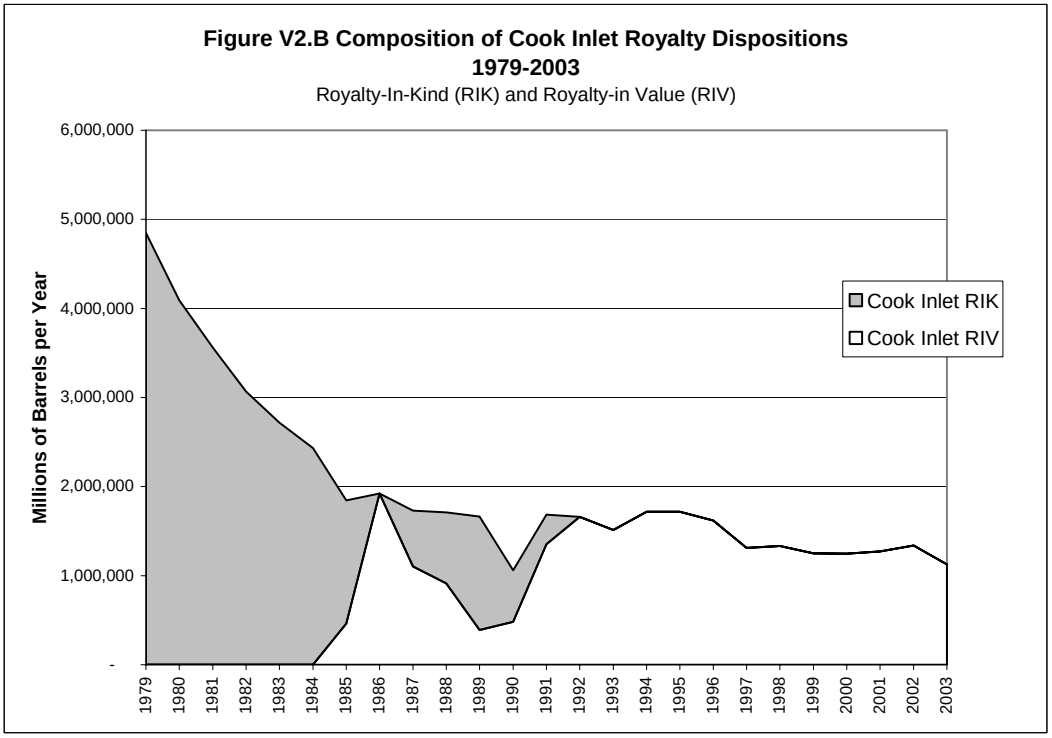


Figure V.3 Major North Slope Royalty in-Kind Sales Contracts

1979-2003