Alaska North Slope Oil and Gas
A Promising Future or an Area in Decline?

ADDENDUM REPORT

DOE/NETL-2009/1385

April 2009

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Alaska North Slope Terrain

The map shows the geographical region of Arctic Alaska north of the Brooks Range, extending from the Canadian border on the east to the Chukchi Sea on the west. This region includes the Alaska National Wildlife Refuge (ANWR), the Central Arctic (area between the Colville and Canning Rivers), the National Petroleum Reserve Alaska (NPRA), the Beaufort Sea Outer Continental Shelf (OCS), and the Chukchi Sea OCS areas. Oil fields are shown in light green and gas fields in pink.

Foreword

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), Arctic Energy Office; the U.S. Department of Interior's Minerals Management Service, Alaska OCS Region; the U.S. Department of Interior's Bureau of Land Management, Alaska State Office jointly funded an Alaska North Slope oil and gas resource assessment published in August 2007, entitled Alaska North Slope Oil and Gas—A Promising Future or an Area in Decline?. The results were published in two reports, the Summary Report, DOE/NETL-2007/1280, which summarized the results of the detailed analysis contained in the Full Report, DOE/NETL-2007/1279 (http://www.netl.doe.gov/technologies/oil-gas/AEO/main.html).

The purpose of the 2007 report was to provide a detailed assessment and analysis of Alaska North Slope oil and gas resources and the interrelated technical, economic, and environmental factors controlling development of those resources. Science Application International Corporation (SAIC), Alaska Energy Office, performed the study under contract to DOE–NETL.

This addendum report was prepared to update the results of additional drilling and developments that occurred after the publication of the 2007 report, since the majority of the work on the previous 2007 report was done in 2005 and was based on production through December 31, 2004. This addendum report is based on drilling, development, and production history through December 31, 2007. The basic geological framework, petroleum geology, and history of development have not changed and are not updated from the 2007 report. Developments and future exploration potential are updated based on the latest information and production forecasts for technically recoverable resources are updated for producing fields, fields and pools under development, and known fields and pools under evaluation. Generalized production forecasts for undiscovered resources in the exploration areas described in the geology section, Section 2, are also presented.

An economic analysis was not undertaken for this update because, even though the changes in Alaska production taxes were enacted by the Alaska Department of Revenue in November 2007, the data needed to provide an adequate analysis are not publicly available at this time.

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ALASKA NORTH SLOPE OIL AND GAS:
A Promising Future or an Area in Decline?

Abstract

This report presents an update of the detailed assessment and analysis of the oil and gas resources on Alaska's North Slope published in August 2007 entitled Alaska North Slope Oil and Gas–A Promising Future or an Area in Decline? U. S. Department of Energy, DOE/NETL-2007/1279. The region covered in the assessment is the Arctic Alaska area north of the Brooks Range, extending from the Canadian border on the east to the Chukchi Sea Outer Continental Shelf (OCS) on the west. Five sub-provinces are evaluated: the 1002 Area of the Arctic National Wildlife Refuge (ANWR), the Central Arctic (area between the Colville and Canning Rivers), the National Petroleum Reserve Alaska (NPRA), the Beaufort Sea OCS, and the Chukchi Sea OCS. Land ownership consists of a combination of federal lands, state lands, and Alaska native lands. The assessment published in 2007 included: (a) a review of the regional geology relative to oil and gas resources; (b) an engineering assessment of the currently producing fields, known fields with announced development plans, and known fields with potential for development in the next few years; (c) impact of major gas sales on oil and gas resource development: and (d) possible forecasts of composited production rates for exploration areas. This report includes an update of the Arctic Alaska resources based on drilling, development, and production history through December 31, 2007. The basic geological framework, petroleum geology, and history of development have not changed and are not updated and the reader is referred to the 2007 report. Production forecasts for technically recoverable resources (oil, natural gas, and natural gas liquids (NGLs)) are updated for producing fields, fields and pools under development, and known fields and pools under evaluation. Generalized production forecasts for undiscovered resources in the exploration areas described in the geology section, Section 2, are also presented.

An economic analysis was not undertaken for technically recoverable resources in this Addendum report. The details of the application of the recent changes in Alaska production taxes to a profit-based tax structure have been worked out by the Alaska Department of Revenue, but the data needed to provide an adequate analysis are not publicly available at this time.

The future projections were viewed from two perspectives, near term (2008 to 2018/2020) and long term (2018/2020 to 2050), with the near term being oil-centered and the long term marked by the emergence of gas as a major, if not dominant, factor in exploration and development activities. The future for Alaska North Slope (ANS) oil and gas ranges from very promising to limited depending on how many of the following assumptions apply: (1) the 1002 Area of ANWR is opened for exploration and development, (2) exploration is allowed in the most prospective areas of NPRA, (3) the Beaufort Sea OCS and Chukchi Sea OCS are available for exploration and development without major restrictions on area or timing, (4) an ANS natural gas pipeline for major gas sales (refered to as a "gas pipeline" in the remainder of the abstract) is operational by 2018 to 2020, (5) oil and gas prices prices recover to favorable high values in the near future, and (6) state of Alaska and federal fiscal policies remain stable and supportive of the

huge investments that will be required. The future prospects become progressively less promising as these assumptions are removed.

For the most part, the sharp drop in oil prices (and corresponding drop in gas prices) starting in mid-2008 and continuing to the present will no doubt adversely impact exploration and development planning and activities in the Arctic region in the near-term as oil companies review their economic situation. However, favorable world oil prices and domestic gas prices will most likely recover as the economy recovers, thus possibly changing the timing of some activities, but with minimal impact on the overall scope of Arctic exploration and development planning.

Key findings are summarized below:

- Oil and natural gas liquid (NGL) production from Alaska's North Slope began in 1977 and increased to 2.2 million barrels per day by 1988, representing 25% of the U.S. domestic production. Production has since declined to about 720,000 barrels per day in 2007, but still represents about 14% of the U.S. domestic production.

- All oil production to date has been from fields in the Central Arctic (Colville-Canning area) on state lands and adjacent waters of the Beaufort Sea. (Note: The Northstar Unit produces from both state and federal waters in the Beaufort Sea). By the end of 2007, Alaska North Slope oil fields had produced 15.7 billion barrels of oil, or about 72% of the estimated technically recoverable oil from the currently developed fields. The remaining technically recoverable oil from these fields is about 6.1 billion barrels.

- Discovered technically recoverable natural gas resources on the Alaska North Slope are estimated to be about 35 trillion cubic feet. No natural gas is currently exported off the North Slope because there is no gas pipeline to transport the gas to markets.

- From an exploration perspective, the North Slope and adjacent areas are not representative of mature petroleum provinces. The majority of the wells in both the state onshore and near-shore Beaufort Sea are clustered along the Barrow Arch trend, with a drilling density of approximately one exploration well per 22 square miles. Only 45 of the 301 North Slope exploration wells have been located south of 70º north latitude. This area, which constitutes nearly 75% of the state acreage, has a well density of one well per 383 square miles.

- In the short term, 2005 to 2018/2020, exploration efforts are forecast to result in the addition of about 2.9 billion barrels of economically recoverable oil and 12 trillion cubic feet of economically recoverable gas. Oil exploration is expected to target primarily oil resources in the Central Arctic on state lands and adjacent state waters, NPRA, and the Beaufort Sea OCS. Gas exploration is expected to begin in earnest when a gas pipeline is assured and will initially target the Central Arctic foothills area, south of the current oil producing area.

- In the long term, 2018/2020 to 2050, exploration success and development is expected to involve activities in all five sub-provinces under the **optimistic assumptions** and is estimated to total 28 billion barrels of economically recoverable oil and 125 trillion cubic feet of economically recoverable gas. The expected oil and gas reserve additions are widely distributed in all the geographic areas.

- For the complete study interval from 2005 to 2050, the forecasts of economically recoverable oil and gas additions, including reserves growth in known fields, is 35 to 36 billion barrels of oil and 137 trillion cubic feet of gas. These **optimistic estimates** assume high oil and gas prices recover in the near future, stable fiscal policies, and **all areas** open for exploration and development. For this optimistic scenario, the productive life of the Alaska North Slope would be extended well beyond 2050 and could potentially result in the need to refurbish the Trans Alaska Pipeline System (TAPS) and/or add a new pipeline and add capacity to the gas pipeline.

- The forecasts become increasingly pessimistic if the assumptions are not met as illustrated by the following scenarios.
    1. If the ANWR 1002 area is removed from consideration, the estimated economically recoverable oil is 29 to 30 billion barrels of oil and 135 trillion cubic feet of gas.
    2. Removal of ANWR 1002 and the Chukchi Sea OCS results in a further reduction to 19 to 20 billion barrels of oil and 85 trillion cubic feet of gas.
    3. Removal of ANWR 1002, Chukchi Sea OCS, and the Beaufort Sea OCS results in a reduction to 15 to 16 billion barrels of oil and 65 trillion cubic feet of gas.
    4. Scenario 3 and no gas pipeline reduces the estimate to 9 to 10 billion barrels of oil (any gas discovered will likely remain stranded).

  Some combination of these hypothetical scenarios is more likely to occur than the optimistic estimates.

- The study examined two resource development cases related to the presence or absence of significant natural gas sales arising from construction of a gas pipeline.
    - The assessment for the **No-Major-Gas-Sales** case results in an estimate of remaining technically recoverable oil of 7.3 billion barrels of oil for the fields analyzed (i.e., currently producing fields, known fields with pending or announced development plans, and known fields with near-term development potential).
    - For the **Major-Gas-Sales** case, the development of the Point Thomson field is estimated to result in an additional 400 million barrels of recoverable oil and condensate. A reserve decline in the Prudhoe Bay field is estimated to be about 234 million barrels of oil, resulting in an estimate of about 6.56 billion barrels of remaining technically recoverable oil from the known Alaska North Slope fields.

- The estimated gas reserves in the Prudhoe Bay and Point Thomson fields will provide 32 trillion cubic feet of the 57.5 trillion cubic feet of natural gas required to support a gas pipeline project at 4.5 billion cubic feet per day for a 35-year life.

- The TAPS minimum flow rate of about 200,000 barrels of oil per day will be reached in about 2045, absent new developments or reserves growth beyond the forecasted technically remaining reserves. An Alaska gas pipeline and gas sales from the Point Thomson field and the associated oil and condensate would provide another boost to oil production but would not extend the life of TAPS. A shutdown of TAPS would potentially strand about 1 billion barrels of oil reserves from the fields analyzed.

- Exploration in the 1002 Area of ANWR (including native corporation in-holdings and state Beaufort Sea waters) is highly significant because this sub-province contains an estimated 10.3 billion barrels of oil in 1.9 million acres (5,475 barrels of oil per acre). In comparison, NPRA contains an estimated 10.6 billion barrels of oil in 24.2 million acres (440 barrels per acre). Opening the ANWR 1002 Area would significantly increase exploration activity and increase the potential for discovery of additional oil and gas reserves.

- The geological evidence for the Alaska North Slope areas indicate that oil and gas fields of sufficient size could be found to support development, provided oil and gas prices are adequate and the fiscal and regulatory environment are supportive of the large investments that will be required.

- Issues that have the *potential* for preventing development of a given field or set of fields on the Alaska North Slope include land access; extent of requirements for dismantlement, removal, and restoration of facilities and infrastructure; marine mammal protection with respect to development of offshore resources and potential impacts on bowhead whales, a species listed under the Endangered Species Act; water availability for constructing ice roads and exploration pads; and gravel availability for constructing development and production facilities and roads. Some may be solved by further advances in technology, while others may ultimately prevent development in a given location.

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ACRONYMS AND ABREVIATIONS

% .... Percent
2D .... Two Dimensional
3D .... Three Dimensional
ACE .... Army Corps of Engineers
ACMP .... Alaska Coastal Management Program
ADEC .... Alaska Department of Environmental Conservation
ADFG .... Alaska Department of Fish and Game
ADGC .... Alaska Division of Governmental Coordination
ADNR .... Alaska Department of Natural Resources
ADOR .... Alaska Department of Revenue
ADOG .... Alaska Division of Oil and Gas
AGP .... Alaska Gas Pipeline
AIMS .... Alaska Incident Management System
AIRFA .... American Indian Religious Freedom Act
ANCSA .... Alaska Native Claims Settlement Act
ANILCA .... Alaska National Interest Lands Conservation Act
ANS .... Alaska North Slope
ANWR .... Alaska National Wildlife Refuge
AOGCC .... Alaska Oil and Gas Conservation Commission
API .... American Petroleum Institution
ARCO .... Atlantic Richfield Oil Company
ASRC .... Arctic Slope Regional Corporation
BACT .... Best Available Control Technology
BAT .... Best Available Technology
BBO .... Billions of Barrels of Oil
BCF .... Billions of Cubic Feet of Gas
BCFD .... Billion Cubic Feet per Day
BLM .... Bureau of Land Management
BO .... Barrels of Oil
BOPD .... Barrels of Oil per Day
BTU .... British Thermal Unit
BWPD .... Barrels Water Per Day
CAA .... Clean Air Act
CAH .... Central Arctic Herd
CBNG .... Coalbed Natural Gas
CEQ .... Council on Environmental Quality
CERCLA .... Comprehensive Environmental Response, Compensation, and Liability Act
CFPB .... Cubic Feet per Barrel
CH4 .... Methane
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
Crk .... Creek
CRU .... Colville River Unit
CWA .... Clean Water Act
CZMA .... Coastal Zone Management Act

DAQ..Division of Air Quality
DGGS.......................................Division of Geological and Geophysical Services
DHS..Department of Homeland Security
DIU ....Duck Island Unit
DMLW...Alaska Department of Mining, Land and Water
DOE ....U.S. Department of Energy
DOI ....U.S. Department of Interior
DOT ....Department of Transportation
DR&R ....Dismantle Removal and Restoration
E&P ....Exploration and Production
EIA ....Energy Information Administration
EIS..Environmental Impact Statement
ELF ....Economic Limit Factor
EOR...Enhanced Oil Recovery
EPA ....Environmental Protection Agency
ERR...Economically Remaining Reserves
ESA ....Endangered Species Act
EUR..Economical Ultimate Reserves
FLIR..Forward Looking Infrared Photography
FLPMA.....................................Federal Land Policy and Management Act
Fms..Formations
FOSC...Federal On Scene Coordinator
ft ....Feet
FWCA..Fish and Wildlife Coordination Act
FWPCA......................................Federal Water Pollution Control Act
FWS ....U.S. Fish and Wildlife Service
GAO..U.S. General Accounting Office
GG&E ....Geophysical, Geologic and Exploration
GOR ....Gas Oil Ratio
GRZ/ HRZ ....Condensed Radioactive Shale
H^2S ....Hydrogen Sulfide
Hc..Hydrocarbons
HI ....Hydrogen Index
HMTA.................................Hazardous Materials Transportation Act
IPA ....Initial Participating Area
KIC..Kaktovik Inupiat Corporation
KRU ....Kuparuk River Unit
LCU...Lower Cretaceous Unconformity
m ....Meters
m.y. ....Million Years
Ma ....Million of Years Ago
MB ....Thousands of Barrels of Petroleum Liquids
MBO ....Thousand Barrels of Oil
MBO ....Thousands of Barrels of Oil
MBOPD ....Thousands of Barrels of Oil Per Day
MCF ....Thousand Cubic Feet

MD	Measured Depth
md	Millidarcies
MEFS	Minimum Economic Field Size
MI	Miscible Rich Gas Injection
MMB	Millions of Barrels of Petroleum Liquids
MMBO	Million of Barrels of Oil
MMBOE	Million Barrels of Oil Equivalent
MMBOPD	Millions of Barrels of Oil Per Day
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MOU	Memorandum of Understanding
MPU	Milne Point Unit
MWAG	Miscible Water Alternating Gas Process
NAGPRA	Native American Graves Protection and Repatriation Act
NCP	National Oil and Hazardous Substances Pollution Contingency Plan
NEPA	National Environmental Policy Act
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NETL	National Energy Technology Laboratory
NHPA	National Historic Preservation Act
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPR	Naval Petroleum Reserve
NPRA	National Petroleum Reserve Alaska
NPRPA	Naval Petroleum Reserves Production Act
NPS	National Park Service
NRHP	National Register of Historic Places
NSB	North Slope Borough
NSU	North Star Unit
O^3	Ozone
OCS	Outer Continental Shelf
ODPCP	Oil Discharge Prevention and Contingency Plan
OGIP	Original Natural Gas in Place
OHSPC	Oil and Hazardous Substance Pollution Control
OOIP	Original Oil in Place
OPA	Oil Pollution Act
OPEC	Organization of Petroleum Exporting Countries
PA	Participating Area
Pb	Lead
PBU	Prudhoe Bay Unit
PCB	Polychlorinated Biphenyl
PM	Particulate Matter
PPA	Pressure Point Analysis
PTU	Point Thomson Unit
PSD	Prevention of Significant Deterioration

RCRA	Resource Conservation and Recovery Act
RHA	Rivers and Harbors Act
Ro	Vitrinite Reflectance
S	Sulfur
SAIC	Science Applications International Corporation
SARA	Superfund Amendments and Reauthorization
SDWA	Safe Drinking Water Act
SEC	Securities and Exchange Commission
SHPO	Alaska State Historic Preservation Office
SO^2	Sulfur Dioxide
SPCC	Spill Prevention Control and Countermeasure
SPE	Society of Petroleum Engineers
Ss	Sandstone
TAPS	Trans Alaska Pipeline System
TCF	Trillion Cubic Feet of Gas
TOC	Total Organic Carbon
TRR	Technical Remaining Recovery
TSCA	Toxic Substance Control Act
TSP	Total Suspended Particulates
TUR	Technical Ultimate Recovery
UAF	University of Alaska Fairbanks
UIC	Underground Injection Control
USCG	U.S. Coast Guard
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WAG	Water Alternating Gas
Wt	Weight
WTI	West Texas Intermediate
yr	Year

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ALASKA NORTH SLOPE OIL AND GAS
A Promising Future or an Area in Decline?

1. INTRODUCTION

The purpose of this addendum report is to update the data provided in the original report, released in 2007. Those data were, in most part, based on pre-January 1, 2005, sources. The purpose of this addendum report is to provide an updated detailed assessment and analysis of Alaska North Slope (ANS) oil and gas resources. Changes and additions to the original 2007 report are shown in this addendum report as bold text. The ANS region includes the area north of the Brooks Range to the Beaufort Sea and extends from the Chukchi Sea on the west to the Canadian border on the east. This area includes the National Petroleum Reserve-Alaska (NPRA), the Central Arctic, the Alaska National Wildlife Refuge (ANWR), and the Beaufort Sea and Chukchi Sea Outer Continental Shelf (OCS) areas, as shown in Figure 1-1.

The results provide a source of detailed information for planning and decision-making by the U.S. Department of Energy (DOE), other federal agencies, and state of Alaska agencies to improve the prospects for continued development of ANS oil and gas. The scope includes currently known onshore and offshore fields on the ANS (developed and undeveloped) and prospective development areas including NPRA, the Beaufort Sea and Chukchi Sea OCS areas, and the 1002 Area of ANWR. Exploration in the 1002 Area of ANWR will require approval by the U.S. Congress and the President. The onshore portion of this region is all within the North Slope Borough.

In prospective development areas, estimated characteristics, locations, and magnitude of the undiscovered oil and gas resources on state of Alaska, federal, and native lands are described using the latest geological information available and analytic reservoir engineering calculations to estimate recoverable oil and gas resources. The effects of infrastructure, access to infrastructure, environmental regulations, advanced technology development, and development of an ANS natural gas pipeline for major gas sales (refered to as "gas pipeline" in the remainder of this addendum report) on the future viability of ANS oil and gas production are described.

ANS development has been limited to the northern portion of the Central Arctic region, on state lands and near-shore in the Beaufort Sea between the Colville River on the west and the Canning River in the east, as seen in Figure 1-2.[1] Successful exploration has progressed into eastern NPRA and has lead to pending development of three satellite fields near the Colville River Unit.

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[1] Additional maps at larger scale are available at the Alaska Department of Natural Resources Division of Oil and Gas web site. http://www.dog.dnr.state.ak.us/oil/products/maps/northslope/northslope.htm

Figure 1-1. The North Slope, Alaska, and adjacent Chukchi and Beaufort Seas. (map by Mapmakers Alaska, Palmer, AK)

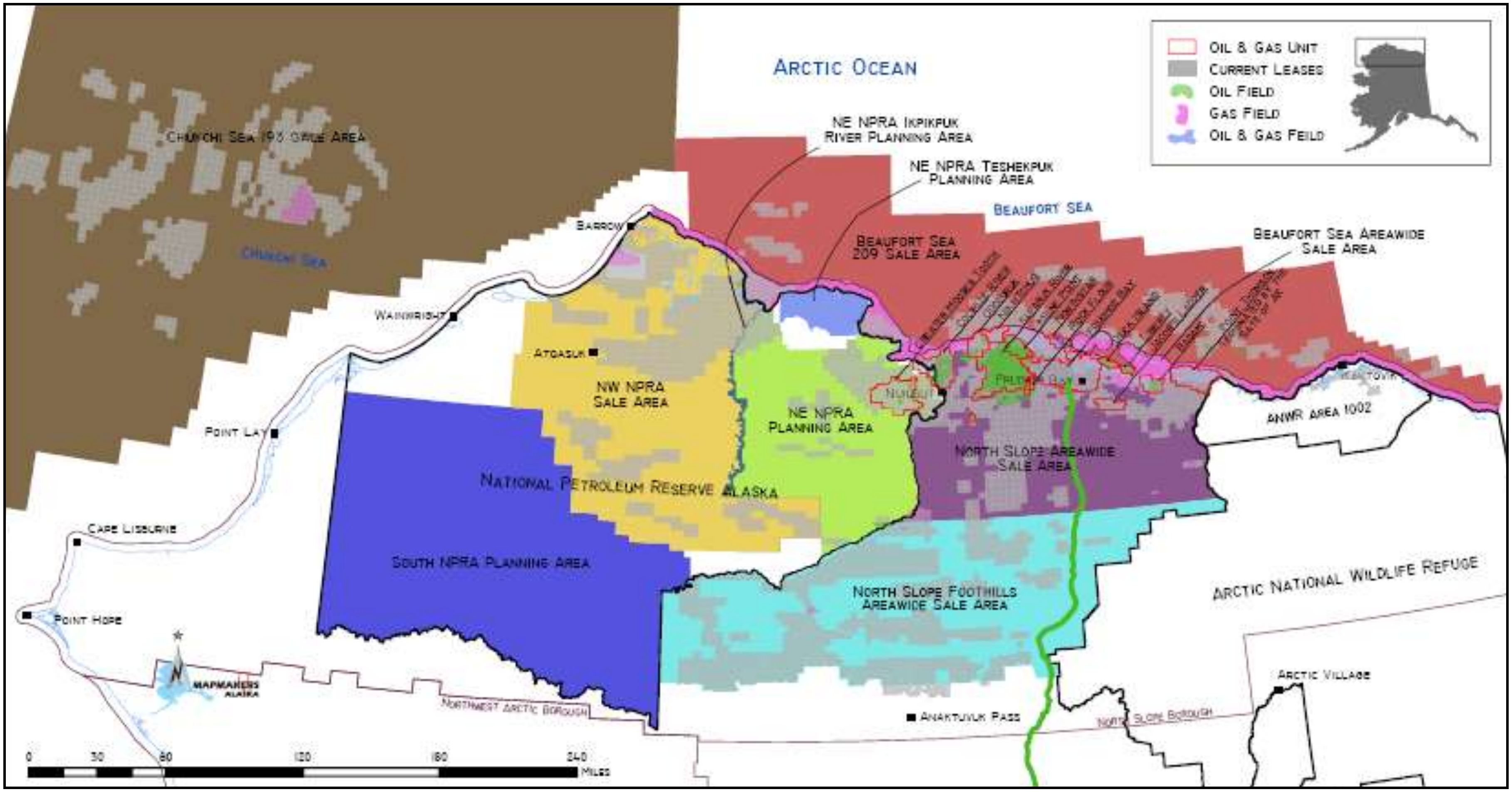

Figure 1-2. Overview of oil and gas activity, North Slope, Beaufort and Chukchi Seas, Alaska.

1.1 Oil

The state of Alaska currently receives almost 90% of its general fund revenues from petroleum revenues (royalties, production taxes, property taxes, and corporate income taxes) and will remain heavily dependent on these revenues for the foreseeable future. Production from Alaska is critical to the United States, as illustrated in Figure 1-3. Since 1978, ANS fields, driven by the Prudhoe Bay and Kuparuk oil fields, have comprised up to 25% of U.S. domestic crude oil production and currently comprise only about 14% of U.S. domestic production. **The current daily production rate (as of December 2008) is approximately 720,000 barrels of oil and natural gas liquids (NGLs) per day or about 36% below the peak production levels of the late 1980s. NGLs contribute about 60,000 barrels per day to the current production total.**

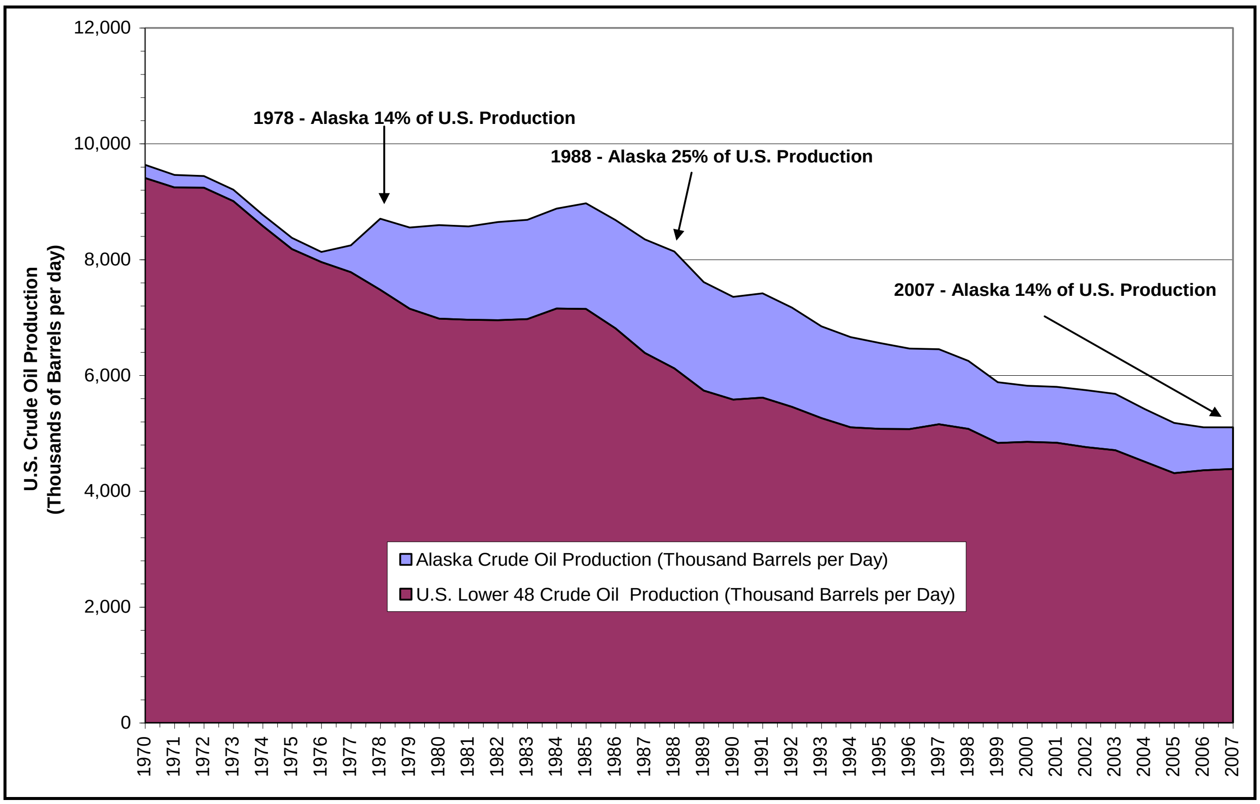

Figure 1-3. Lower 48 and Alaska crude oil production. (Energy Information Administration http://tonto.eia.doe.gov/dnav/pet/pet_sum_crdsnd_adc_mbblpd_a.htm)

The ANS production decline has been dominated by the continuing decline of Prudhoe Bay production as shown in Figure 1-4. The discovery and development of the Alpine and Northstar fields and satellite fields near the existing infrastructure has tempered this decline. **However, unless there are significant future discoveries and commercial development, ANS production from currently producing fields could reach the estimated minimum mechanical limit for Trans Alaska Pipeline System (TAPS) throughput of about 200,000 barrels of oil per day (BOPD) (State Appraisal Review Board, 2007) by 2039, as shown on** Figure 1-4**. With the addition of production from fields under development and under evaluation, this minimum throughput capacity is not reached until 2045.** The minimum flow rate could be sustained by reducing the number of pumps to one pump per station at pump stations 1, 3, 4, and 9. TAPS is currently configured with three pumps at each of these four pump stations. **The strategic reconfiguration program allows Alyeska to vary the crude oil throughput from 200,000 to 1,100,000 BOPD (Petroleum News (PN), 2007f).** At the peak production rates in 1988, 10 pump stations were operating. Throughput could be increased to about 2,000,000 BOPD by adding pump skids and returning idled pump stations to service. The large number of small fields making up the current and projected production shows just how difficult it has been to find additional giant fields to replace declining Prudhoe Bay and Kuparuk River field production.

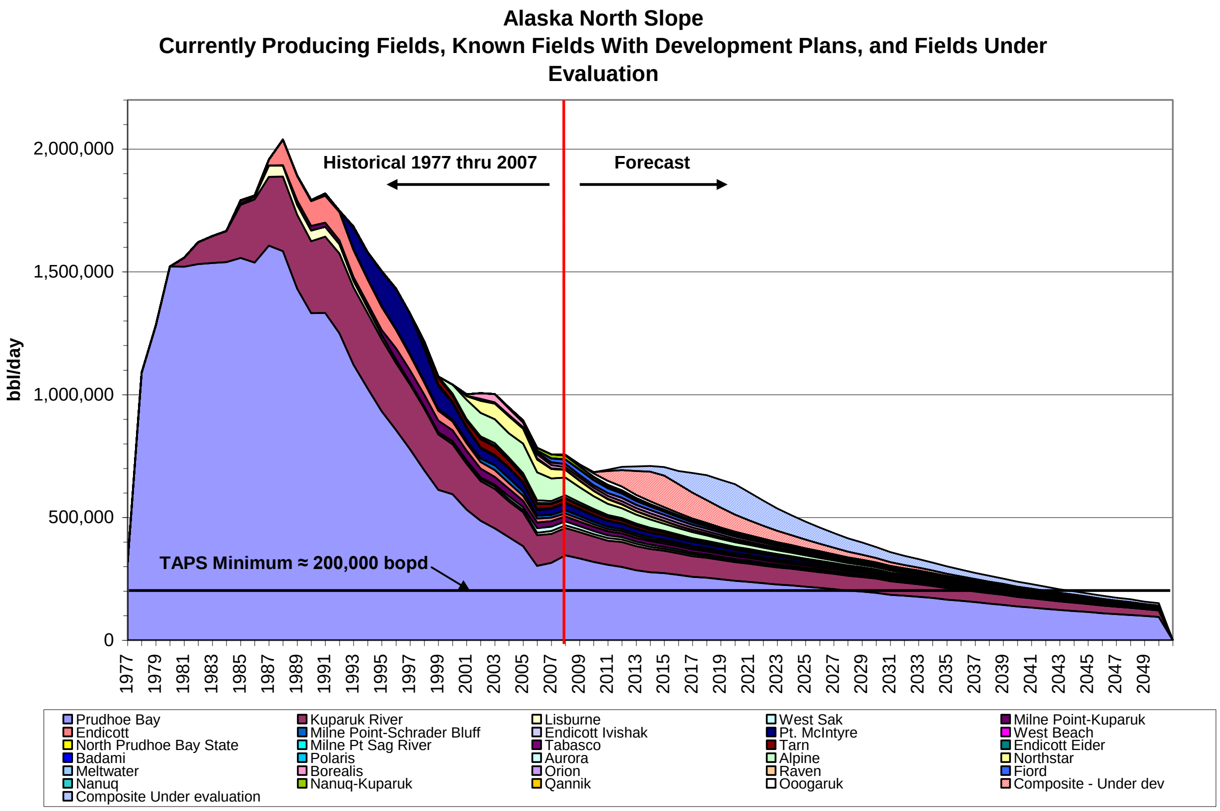

Figure 1-4. Alaska North Slope historical and forecast production.

(Alaska Oil and Gas Conservation Commission (AOGCC) database for history and Section 3 for forecasts.)

1.2 Natural Gas

No ANS natural gas has been sold except for field operations and local use on the ANS. This situation will continue until a gas pipeline is built to deliver the gas to U.S. Lower 48 or world markets. Gas-to-liquids (GTL) technology, which would allow the natural gas to be converted into a liquid petroleum product for transport in TAPS, has been studied, but a gas pipeline appears to be the most desirable option. In **this addendum report it is assumed that a gas pipeline will be in place by 2018 to 2020 and that this will stimulate aggressive exploration for natural gas and oil.**

Exportable hydrocarbon natural gas reserves (produced gas less carbon dioxide (CO_2) and lease use, local sales, and shrinkage) are estimated at 23.7 trillion cubic feet (TCF) for the Prudhoe Bay Unit (PBU) and 8 TCF for the Point Thomson Unit (PTU), for a total of 31.8 TCF. A higher recovery factor for PBU and PTU, or additional small amounts from other currently producing fields, will be required to provide the total of 35 TCF frequently referred to in discussions of ANS gas reserves.

Gas production for use in field operations is common on the ANS. Prudhoe Bay's gas production rate is currently about 7.8 billion cubic feet per day (BCFD), of which about 7.2 BCFD is reinjected. Natural gas reinjection has had a positive impact on oil recovery efficiency in PBU and in other producing fields. In addition, miscible rich gas injection (MI), using a combination of natural gas and NGLs, has been used effectively for enhanced oil recovery (EOR) processes in the Prudhoe Bay and Kuparuk River oil fields. Natural gas injection and waterflooding to enhance recovery from the huge viscous, heavy oil resource overlying the Prudhoe Bay, Kuparuk River, and Milne Point field areas (25 to 30 billion barrels of original oil in place (OOIP)) is proving to be economical when coupled with new technology for multilateral horizontal wells and new completion and production technology.

Enhanced oil recovery using ANS natural gas is expected to continue to be an important and profitable use for natural gas even after an Alaska gas pipeline is constructed to delivery ANS gas to market. Carbon dioxide that must be removed from Prudhoe Bay and Point Thomson natural gas prior to sale is expected to be used for EOR as well.

Technology advancements in the last 10 years, including 3-D seismic and extended reach and multilateral horizontal drilling, have made numerous small satellite fields near PBU and Kuparuk River Unit (KRU) economically viable and slowed the ANS production decline, as illustrated in Figure 1-4. Incremental production developed since 1995 accounts for more than 30% of the total ANS production (Alaska Division of Oil and Gas (ADOG), 2004). The Alpine field in the Colville River Unit and the offshore Northstar field are recent examples of stand-alone fields that have been developed using advanced technology for drilling and production. These technology advancements have also reduced the footprint of the development and the resulting environmental impact. Northstar is offshore in state of Alaska and federal waters of the Beaufort Sea and is the first field to produce from federal waters in the Arctic. The discovery of the Alpine field and the play type it represents is in large part responsible for the recent increase in potential reserves estimated for NPRA by Bird and Houseknecht (2002). Although, these developments have slowed the decline of ANS production, continued leasing and development are essential to maintain the viability of TAPS and other infrastructure in the long term to support future development.

Exploration, development, and operations on the North Slope have been dominated by a few major oil companies (British Petroleum Alaska (BP Alaska), ConocoPhillips, ChevronTexaco, and ExxonMobil), or their predecessors. These companies own varying proportions of the unitized fields, the facilities, and TAPS. Development of major ANS gas reserves will likely occur in a similar manner with the gas pipeline owned by a consortium of companies and, possibly, the state of Alaska. **However, lease sales during 2008 for NPRA, state lands, and the Beaufort and Chukchi Sea OCS areas suggest independent operators**

and major operators will become increasingly important to stakeholders affecting future decision-making processes concerning the export of resources from the North Slope. The increase in the number of companies will potentially increase the amount of investment that can occur on the ANS. **This has been realized in the most recent Chukchi Sea lease sale, and the exploration drilling in the Central North Slope region by Chevron in the White Hills area and Anadarko in the old Gubic gas field and adjacent foothills prospects.**

1.3 Scope and Approach

The Geological Assessment, Section 2, contains a comprehensive, region-by-region, description of the ANS oil and gas resource base and an assessment of oil and gas reserves, reserves growth in producing fields, reserves growth in discovered but undeveloped fields, and potential reserve additions through additional exploration. **The assessment, as modified in 2008, addresses two time frames – near term (2008 to 2018/2020) and long term (2018/2020 to 2050). The near term focuses on continued oil production but begins the transition to oil and gas production in the long term, assuming a gas pipeline is constructed and becomes operational by 2018 to 2020.** The ANS regional geological framework, petroleum geology, exploration history, and existing fields are first described to provide a basis for understanding prior exploration and development activities, to develop a framework for assessing current and future opportunities, and to estimate technically recoverable oil and gas that could be developed by 2050.

Historically, any treatment of petroleum geology of the North Slope has been strongly focused on its oil potential, with little attention to the area's vast conventional gas resources and even less attention to unconventional resources such as coalbed natural gas (CBNG) and gas hydrates.

Because the ANS contains large quantities of coal, the potential for CBNG production is significant. A U.S. Geological Survey (USGS) assessment of undiscovered CBNG was completed in 2006, and a mean estimate of undiscovered, technically recoverable resources gives a potential of about 18 TCF of CBNG (Roberts et al., 2006). However, more attention is being focused on gas hydrates. DOE's National Energy Technology Laboratory (NETL) leads a major, inter-agency, research program underway to assess the nation's gas hydrate potential (DOE, 2006b). One major project within hydrates research program is aimed at ANS gas hydrate reservoir characterization. According to Minerals Management Service (MMS) and USGS estimates (PN, 2005p; Collett, 2004), the ANS may contain as much as 590 TCF of in-place gas in permafrost-associated gas hydrates. Collett (2004) reports that the volume of gas within the known gas hydrates of the Prudhoe Bay-Kuparuk River infrastructure area alone may exceed 100 TCF of gas in place. Ongoing research efforts will attempt to resolve the numerous technical challenges that must be overcome before this potential resource can be considered an economically producible reserve (Collett, 2004).

At this time, because natural gas recovery from CBNG and gas hydrate resources has not been demonstrated, there is no basis upon which to assess their economic feasibility. Therefore, they are not discussed further.

The **Engineering Evaluation, Section 3,** contains the engineering evaluation of the ANS oil and gas producing region. A summary discription of individual pool production history, field and reservoir performance observations, production forecasts for each pool and field, and estimated technical ultimate recovery (TUR) are presented in Section 3. Section 3 is divided into currently producing fields, fields with announced development plans, and known fields with potential for development in the near future. Also discussed in Section 3 are the estimates for natural gas that will be available from the known major gas resources from the Prudhoe Bay and Point Thompson fields when a gas pipeline becomes available.

2. Geological Assessment of the Alaska North Slope

The oil resources of the North Slope of Alaska have been, are, and will be for the foreseeable future, critical to the United States and state of Alaska. Since 1978, these fields, driven by production from Prudhoe Bay and Kuparuk oil fields, have supplied as much as 25% of domestically produced oil. **As of December 2007, the oil and NGL production was approximately 720 thousand barrels of oil per day (MBOPD) or about 36% of the peak production levels.**

From discovery of the Prudhoe Bay field in 1968 and the start-up in 1977 until the present, all commercial oil production has been from the northern portion of the Colville-Canning province, the area between the Colville and Canning Rivers, and from the immediately adjacent offshore state and federal waters (Figure 2-1). Production is just commencing in the northeastern portion of the NPRA. **It is anticipated that oil exploration and production will expand westward and southward into NPRA, southward within the Colville-Canning area, offshore into state waters adjacent to NPRA and ANWR, OCS waters of the Beaufort and Chukchi Seas, and perhaps into the 1002 Area of ANWR.**

Figure 2-1. North Slope Alaska and adjacent Chukchi and Beaufort Seas.

To date, all commercial production has been oil. Gas has been produced and used for local field operations and enhanced recovery programs with only a very small amount of gas sales to a few local North Slope consumers. The commercialization of the vast gas resources awaits the approval and construction of a gas pipeline to transport gas from the North Slope to major gas markets. When this gas pipeline is a reality, extensive exploration of the southern portions of all the onshore areas will proceed at a more rapid pace, as these areas are widely believed to be gas-prone.

While the near term status of North Slope production appears to be relatively stable, the longer term future, beyond 10 to 12 years (2018 to 2020), is much more uncertain. The decline in production from the major early discoveries is partially offset by more recently discovered but smaller fields (200 to 500 million barrels of oil (MMBO)) and small proximal satellites (25 to 100 MMBO). Maintenance of future production at or above current rates will require some combination of intermediate-size discoveries (500 MMBO ±), continued development of satellite fields, and more intensive development of the heavy oil reservoirs such as West Sak, Schrader Bluff, and Ugnu. Exploration of the federal OCS areas and the 1002 Area of ANWR would significantly increase the probability of long term (through 2050) production maintenance and even growth. **A gas pipeline should provide the impetus for long-term exploration and development in the greater North Slope area. However, because of delays in implementing a process for selecting and funding the gas pipeline, it is doubtful that the gas pipeline issue will be resolved before 2009. Depending on the resolution of these issues, an open season for nominations to the gas pipeline may not occur until sometime late in 2010, with the first gas to market no earlier than 2018.**

There have been some recent discussions and studies relating to building a smaller natural gas sales "bullet-line" pipeline for in-state gas sales from the North Slope to the Fairbanks-Anchorage area market. However, due to the uncertainty of the project and relatively small volume of natural gas involved, installation of an in-state gas sales pipeline is not likely to have a significant impact on North Slope exploration and development activities.

To provide a basis for understanding prior exploration and development activities on the North Slope and to develop a framework for current and future exploration and development opportunities, Sections 2.1 through 2.3 present the regional geological framework, the petroleum geology, and the exploration history, followed by discussions of the existing fields and future exploration/production potential in Sections 2.4 and 2.5.

2.1 Geological Framework of the North Slope (See Thomas et al., 2007)[2]

2.2 Petroleum Geology (See Thomas et al., 2007)[2]

[2] For Sections 2.1 and 2.2 where no changes were needed to the original 2007 report (Thomas, et al., 2007), the reader is referred to that report. In the remainder of Section 2, changes and additions are shown as bold text.

2.3 Exploration and Development

Interest in the hydrocarbon potential of the North Slope commenced when it was recognized that active oil seeps existed in the Cape Simpson area of what is now the NPRA. The birth of North Slope exploration occurred with the evaluation of these seeps in 1909. **This would ultimately lead to exploration activities by both the federal government and the petroleum industry, the drilling of approximately 484 exploration wells (see** Figure 2-2**, page 2-8), and the discovery of the largest oil and gas field in North America.**

The history of exploration and development that has led to this enormous reserve base is presented chronologically by geographic-administrative province in the following sections. To encapsulate this process, a brief chronological summary of significant events is presented in Table 2.1**.**

Table 2.1. Chronology of significant events in the evolution of the oil and gas exploration and development of the North Slope, Alaska (modified from National Research Council, 2003, and updated through August 2, 2008).

Year(s)	Exploration/Development Milestones
Before recorded history	Oil seepages used by native inhabitants of the North Slope
1882	U. S. government representatives learn of oil seeps.
1909	First description of Cape Simpson oil seeps is published.
1914	First oil-related claim is staked.
1922	First industry-sponsored geological investigation of oil potential.
1923	Naval Petroleum Reserve No. 4 (NPR-4) is established.
1923-1926	First analysis of NPR-4 hydrocarbon potential.
1943	Territory of Alaska Bureau of Mines sends field party to the North Slope to investigate oil and gas seepages. Land north of the drainage divide of the Brooks Range withdrawn from public entry by the Secretary of the Interior – Public Land Order 82.
1944	Start of NPR-4 petroleum exploration program
1945-52	Navy-sponsored geophysical studies across NPR-4 result in exploration drilling with un-economic discoveries of oil and gas.
1953	NPR-4 exploration unexpectedly recessed.
1953-1968	Federal geologic field parties continue in NPR-4, Major oil companies begin exploration on the North Slope.
1957	Oil discovered in Cook Inlet.
1958	Public Land Order 82 rescinded. First industry-sponsored geological field programs. Alaska Statehood Act passed.
1958-1966	First of 4 federal lease sales held in 1958, the last in 1966.
1959	Alaska formally admitted as a state.
1960	Establishment of the Arctic National Wildlife Refuge (now ANWR) with 9,000,000 acres about half the size of ANWR today. Public Land Order 82 revoked.
1962	First industry-sponsored seismic program.

Year(s)	Exploration/Development Milestones
1963-1967	First industry exploration drilled on the North Slope, 11 unsuccessful wells drilled, industry interest in the North Slope wanes.
1964	First State of Alaska lease sale on the North Slope.
1965	Area that eventually includes Prudhoe Bay oil field leased.
1967	Drill rig moved from Susie to Prudhoe Bay St. No. 1 location and well spud.
1968	ARCO announces the discovery of the Prudhoe Bay oil field, the largest in North America.
1969	Discovery of Kuparuk, West Sak, and Milne Point oil fields. Lease sales suspended on the North Slope for 10 years because Secretary of the Interior imposes freezes due to native land claims.
1970	National Environmental Policy Act passed.
1971	Alaska Native Claims Settlement Act (ANCSA) passed.
1974-1982	Federally sponsored exploration along the Barrow Arch within NPRA (NPR-4).
1976	Naval Petroleum Reserve-4 is transferred to the Department of the Interior and renamed National Petroleum Reserve-Alaska (NPRA).
1977	Trans-Alaska Pipeline System (TAPS) become operational. Point Thomson gas and light oil field discovered.
1978	Discovery of Endicott field.
I979	Initial leasing of portions of the state and federal outer continental shelf (OCS) waters of the Beaufort Sea.
1980	Alaska National Interest Lands Conservation Act (ANILCA) passed.
1981-Present	Arctic Slope Regional Corporation (ASRC) negotiates exploration agreements with petroleum companies and converts selected acreage to leases - approximately 10 exploration wells are drilled.
1981	First Beaufort Sea OCS exploration well drilled.
1982	Initial leasing of portions of NPRA. Chevron drilled the Livehorse No. 1 on ASRC lands within NPRA.
1983	OCS well, Mukluk No. 1, was the most expensive dry hole ever drilled in the world.
1984	The fourth of four scheduled lease sales in NPRA was cancelled due to lack of industry interest, ending the first episode of NPRA leasing.
1984-1985	Seismic surveys conducted in 1002 Area of the Arctic National Wildlife Refuge (ANWR).
1985	First industry well drilled on federal leases in NPRA, Brontosaurus No. 1, which was a dry hole.
1986	Chevron/BP Kaktovik Inupiat Corporation (KIC) well drilled on ASRC lands within the 1002 Area of ANWR, well is still in confidential status.
1988	Discovery of Pt. McIntyre field in state waters of Beaufort Sea. First OCS lease sale in Chukchi Sea.
1989	First well drilled in Chukchi Sea, Shell Klondike No. 1. Large gas discovery at Shell Burger No. 1 within Kuparuk equivalent strata.
Early 1990s	Last of the 1980s NPRA leases were relinquished.
1991-Present	Satellite field exploration and development gains prominence.
1994	Discovery of the Alpine field, opens up new plays in the Jurassic.
1999-Present	Renewal of leasing in the NPRA - exploration drilling at a pace of 4 to 6 wells per drilling season.
2001	The Beaufort Sea, Northstar field begins production.

Year(s)	Exploration/Development Milestones
2004	Legislation to facilitate gas pipeline construction passed.
2005	**Renewal of interest in Beaufort Sea OCS. Shell returns to Alaska and submits high bids on Hammerhead and Kuvlum, MMS ultimately rejects Kuvlum high bids.**
2007	**Shell and ConocoPhillips acquire 3D seismic data in Chukchi Sea.**
2007-2008	**North Slope gas pipeline plan developed and the Alaska Gasline Inducement Act (AGIA) passed by legislature on August 2, 2008. Competing, non-state-sanctioned gasline proposal by ConocoPhillips and BP Alaska is also advancing independent of AGIA.**
2008	**Chukchi Sea lease sale (OCS 193) was held in February - total high bids of nearly $2.7 billion were submitted, with more than $2.1 billion by Shell and over $500 million by ConocoPhillips.**

Leasing or land availability, is the key component in a successful exploration effort. Without access to the land, the best geological models and economics are for naught. A brief preamble follows to facilitate the understanding of the leasing history as presented in the various segments.

From the original sales in the late 1950s to the present, many millions of acres have been leased. A large portion of that acreage has been evaluated, tested for one or more potential play types, and either successfully developed or released back to the federal or state agency with jurisdiction. Much of the acreage returned to the leasing agency has been reoffered and leased once again as new play concepts are developed, large "anchor" discoveries are made, or oil prices rise sharply, and the cycle is repeated.

As of January 1, 2008, cumulative North Slope production totaled approximately 15.684 billions of barrels of oil (BBO) (and NGLs), an increase of 699 MMBO since January 1, 2005, from 35 pools in eight oil fields, with estimated remaining reserves of 7.03 to 7.39 BBO (Table 2.5). There are 35 TCF generally recognized as proven reserves, awaiting approval and construction of a gas pipeline. An additional 30-plus currently undeveloped oil and gas fields have been discovered (Table 2.5 and Table 2.6).

The exploration and development history of the North Slope is presented as a series of time intervals, within which the various geographic-administrative areas are summarized individually. **The initial time snapshot covers the interval preceding the discovery of the Prudhoe Bay oil field, and the concluding section, Section 2.3.5, summarizes the last 18 years, from 1990 through 2007, with additional comments addressing the significant exploration drilling activity during the winter of 2008 and the magnitude of the breakthrough February 2008 Chukchi Sea lease sale.**

2.3.1 Pre-Prudhoe Bay Discovery (1900 to 1967)

The first evidence of potentially significant petroleum deposits on the North Slope of Alaska came from the oil seepages along the Arctic Coast from Skull Cliff on the Chukchi Sea to Brownlow Point on the Beaufort Sea, with exceptional seeps at Cape Simpson. The first published description of the seeps was in 1909, and in 1922 Standard Oil of California sent a geologic field party to investigate the seeps. The first claim was staked at Cape Simpson in

1914, and in 1921 individuals and industry personnel staked additional claims in areas near Cape Simpson, Peard Bay, and along the Meade, Kukpowruk, and Kokolik Rivers (National Research Council, 2003).

Because of anticipated shortages in oil to fuel the navy's ships and because of the apparent potential of the region, Naval Petroleum Reserve No. 4 (NPR-4) was established by President Harding, Executive Order, No. 3797-A, in February 1923. The boundaries of NPR-4 were based on the occurrence of the known seeps and the regional traverses that had been conducted by federal personnel. The area of NPR-4 as established is about 23,000,000 acres (≈36,000 square miles).

Concurrent with the activities in NPR-4, the area to the east, from the Colville River to the Canada border was being mapped by USGS geologists. Geological mapping and exploration north of the Brooks Range began about 1900, when Lt. G. M. Stoney explored the upper Alatra drainage and crossed the Brooks Range to Chandler Lake (Dutro, 1987) and F. C. Schrader crossed the Brooks Range in 1901 and traversed to the Arctic Coast. His report of the traverse is the first account of the geology of the region. He named the Lisburne Limestone and mapped other units on the north flanks of the Brooks Range. E. de K. Leffingwell, in 1919, was the first geologist to map what is now ANWR. He established the stratigraphic sequence that has been used in its general form to this date. Leffingwell reported oil seeps and oil-stained sandstone in what is now the 1002 Area of ANWR.

From 1920 through the mid 1950s, most of the exploration and evaluation effort on the North Slope was focused in and near NPR-4. From 1923 through 1926, seven USGS parties crossed the Brooks Range and NPR-4, performed reconnaissance scale geological mapping along many of the major rivers, and analyzed the hydrocarbon potential of NPR-4 (National Research Council, 2003).

2.3.1.1 NPRA: Navy Exploration Phase – 1940s and 1950s

Exploration in NPRA (Naval Petroleum Reserve-4 was renamed National Petroleum Reserve-Alaska in 1976) is unique in that it is the only area in Alaska that has been almost exclusively explored and evaluated by the federal government. This situation was largely facilitated by the U. S. Navy and its need for fuel during World War II. The Secretary of the Interior issued Public Land Order 82 in January 1943, which withdrew from entry (subject to preexisting rights) for use in the prosecution of the war, all the generally recognized possible petroliferous areas of Alaska, including all of Alaska north of the drainage divide of the Brooks Range. This enabled the investigations to extend and follow discoveries and favorable trends outside the boundaries of NPR-4. This order was not rescinded until 1960; more than a year after Alaska became the 49th state.

The USGS was intimately involved in the evaluations and, beginning in 1944, conducted 10 extensive and wide-ranging programs to support the evaluation. In keeping with Public Land Order 82, their studies were expanded to include the entire North Slope from the Chukchi Sea to the Canada border (Dutro, 1987). Geophysical studies, including experimental airborne magnetometer, gravity, and seismic surveys, were initiated in 1945 and by 1952 covered a large part of the Reserve. Seismic acquisition of approximately 3,750 line-miles of data covered

67,000 square miles including areas outside of NPR-4. Gravity-meter surveys covered about 26,000 square miles and airborne magnetometer surveys covered 75,000 square miles, nearly all of the coastal plain and much of the foothills of the North Slope (National Research Council, 2003).

In 1945, the exploration drilling phase of the evaluation of NPR-4 was initiated, and a depth limit of 10,000 feet (ft) was established for wells. At that time, this depth was thought to be the economic limit for development in the Arctic. The evaluation effort consisted of a combination of exploration (test) wells and core-test wells. Between 1945 and 1952, a total of 81 wells were drilled, with 35 considered exploration wells (including 11 wells that could be considered delineation of confirmation wells) and 46 core-test wells (Bird, 1981; Schnindler, 1988; Reed, 1958; and National Research Council, 2003, Figure 4-2). The 46 core-test wells ranged in depth from 115 ft in the Simpson core-test No. 1 to 2,505 ft in the Simpson core-test No. 28. Exploration wells ranged in depth from 373 ft at the Knifeblade No. 2 to 11,872 ft in the Oumalik No.1. Only two wells were drilled deeper than the original depth limit of 10,000 ft, and eight additional wells were drilled in the 5,000 to 10,000 ft depth range (Reed, 1958**). Figure 2-2**, **which has been updated to include the post-2004 exploration wells, indicates that 70 exploration wells were drilled during the 1940s and 1950s, rather than the 81 wells cited above.** This difference is attributed to the fact that, for this **addendum** report, the delineation wells at discoveries such as Umiat are not included in the exploration well totals of Figure 2-2.

The first wells were drilled in the Cape Simpson and Umiat areas. While the first Umiat well was drilled in 1945, the Umiat oil field was not discovered until 1950. Beginning in 1945, 31 shallow core-tests were drilled in the Cape Simpson area. Oil was discovered and produced on test but in volumes insufficient to be economic. In 1948, the Barrow high was drilled and no oil was found, but gas was discovered in shallow Jurassic sandstones. The well encountered basement at 2,500 ft. The presence of this basement high followed by additional geophysical surveys delineated the Barrow arch, which the northern limb of the Colville basin and a key feature in the accumulation of much of the oil and gas in the Prudhoe Bay area.

Most of the wells were drilled to evaluate middle Cretaceous objectives in the northern foothills, and 10 structures were tested by 26 wells. Ellesmerian objectives were tested by seven wells on the coastal plain, with five of those wells at Barrow. Three wells in the coastal plain were drilled to test Cretaceous objectives. No pre-Cretaceous intervals were drilled in the southern foothills or northern slopes of the Brooks Range (Bird, 1981), but the Oumalik No. 1 was drilled into the upper part of the Jurassic Kingak Shale. The 36 exploration wells tested a total of 18 different prospects. Twenty-one of the 24 wells, located south of 70° north latitude, were drilled on only four structures (11 at Umiat, 3 at Wolf Creek, 3 at Knifeblade, and 2 at Gubik). The area south of 70° north constitutes approximately 65% of NPR-4 and only six features were tested during this episode of drilling. From both the regional and stratigraphic perspectives the vast majority of NPR-4 was not evaluated in the 1945 to 1952 drilling program.

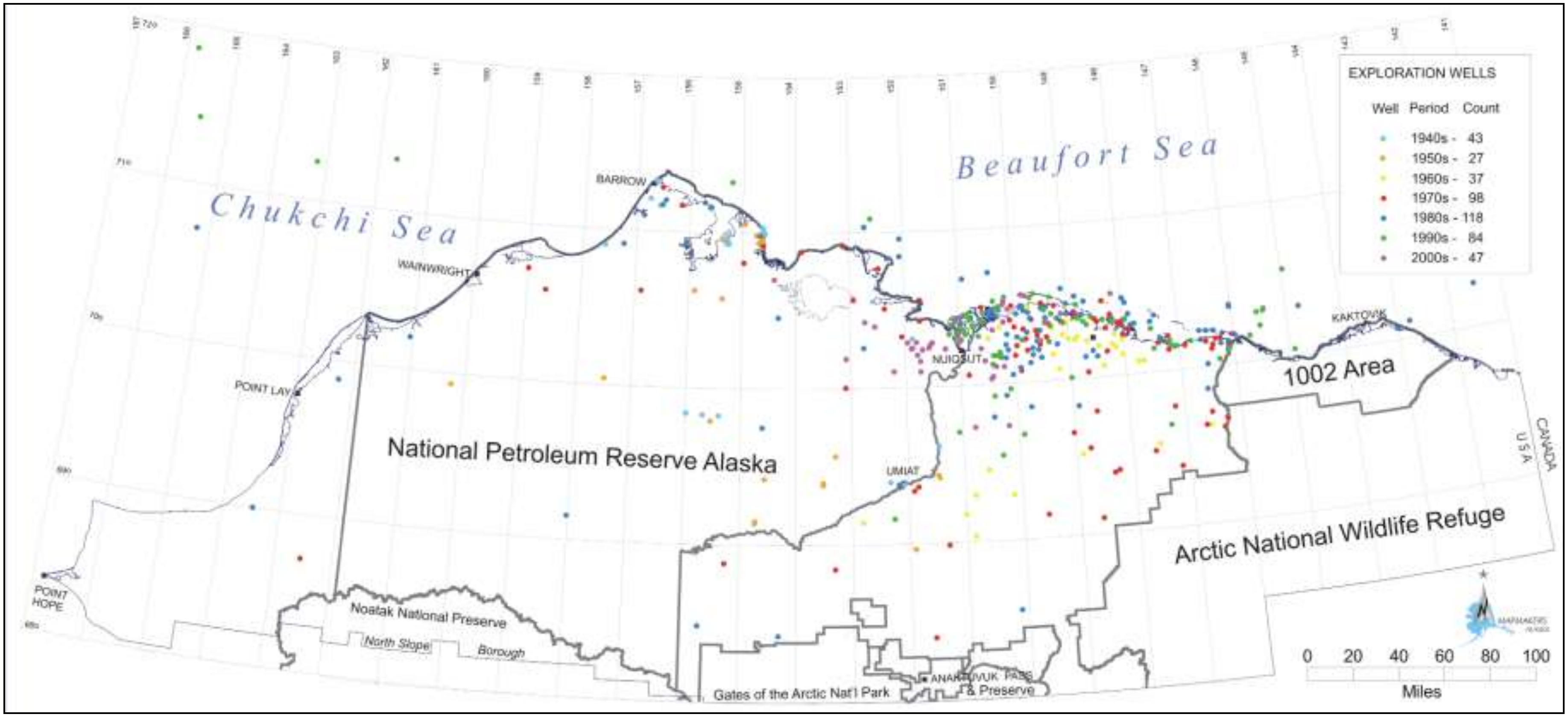

Figure 2-2. Exploration wells of the North Slope and adjacent areas, by decade drilled.

This first round of drilling did result in the discovery of a number of small, sub-economic oil and gas fields (Table 2.6). Three small oil fields were discovered: Umiat, Fish Creek, and Simpson (Reed, 1958; Bird, 1981; Schindler, 1988; and Banet, 1990). Umiat is the largest with estimated recoverable resources of 70 MMBO. These are all Nanushuk Formation accumulations. Five modest to small gas fields were discovered. These are the Gubik, Barrow, Meade, Square Lake, and Wolf Creek **(Table 2.5 and Table 2.6)**. Gubik is the largest, with estimated recoverable resources of approximately 600 billion cubic feet (BCF). The others range from 20 to 58 BCF, and the Barrow field is being produced to supply gas to the community of Barrow. The Barrow field produces from the Jurassic Barrow Sandstone. The Meade, Square Lake, and Wolf Creek accumulations are in the Lower Cretaceous Nanushuk Formation and the Gubik accumulations are in the Upper Cretaceous Schrader Bluff and Lower Cretaceous Nanushuk Formations.

The program was terminated in 1953, and the NPR-4 was largely ignored until the oil embargo renewed interest in developing and maintaining an additional domestic source of oil.

2.3.1.2 Colville-Canning Province: Industry Efforts – 1958 through 1967

While the petroleum industry had been aware of and interested in the potential of the North Slope, the lack of land availability, remoteness, and the costs of operating in this area precluded industry participation. However, in the late 1950s and early 1960s, a number of developments provided the impetus for the industry to commence active exploration of the North Slope.

Four factors contributed to the entry of the industry into the North Slope: (1) encouraging regional geological studies, (2) the NPR-4 exploration program, (3) oil and gas discoveries in Cook Inlet, and (4) the end of the moratorium on land availability on the North Slope. The discovery of commercial quantities of oil and gas in Cook Inlet demonstrated that it was economically feasible to explore for, develop, and market hydrocarbons in and from Alaska. In 1957, Richfield Oil Corporation made the initial discovery at Swanson River on the Kenai Peninsula. This discovery contributed significantly to Alaska statehood in 1959 and provided industry with the incentive for exploration of the other sedimentary basins in the state. The North Slope was one of the areas of interest and was highlighted because of the previous work by the USGS and the Navy's exploration program. Both of these efforts supported the premise that a significant reserve potential existed on the North Slope.

The most important factor was the decision by the federal government, through the Bureau of Land Management (BLM), to make lands available to the industry for leasing. The industry exploration of the North Slope was greatly stimulated by the knowledge that land was to be made available for leasing by the federal government starting in 1958 under basically the same conditions that existed in the Lower 48.

NPR-4 remained a federal reserve and was excluded from those areas open to leasing. Soon after the federal leasing program began and before the state held its first North Slope lease sale, a second large tract of land was removed from consideration through the establishment in 1960 of the Arctic National Wildlife Range (9,000,000 acres). It was later expanded to more than 19,000,000 acres and renamed the Arctic National Wildlife Refuge. The bulk of the onshore area available for leasing and exploration was located between the Colville and Canning Rivers and generally extended from the Beaufort Sea south into the foothills. The total area of about 16,500,000 acres (or 25,800 square miles) also included some acreage west of NPR-4.

In the discussion of industry activities, leasing and exploration activities are summarized separately to provide a less cluttered descriptive narration. However, it should be noted that these various activities are closely related in time and are interdependent.

2.3.1.2.1 Leasing

The federal government offered a total of 18,862,116 acres for lease in sales held in 1958, 1964, 1965, and 1966 (Jamison et al., 1980 and Thomas et al., 1991). Most of the offerings were to the east and southeast of NPR-4 and south of 70° north latitude, but the 1966 sale contained 3,022,716 acres in the area west of NPR-4. The BLM offered the leases as simultaneous filings and in blocks or tracts consisting of four contiguous sections (2,560 acres). Individual lease numbers and dates are shown in Table 2.2.

During the time interval 1958 through 2008, ASRC executed exclusive exploration agreements and leased acreage to a number of companies; Anadarko has such an agreement with ASRC. (Sources: Alaska Department of Natural Resources (ADNR) and MMS on-line files; Kornbrath, 1995; and BLM communication).

Table 2.2. Summary of North Slope and adjacent OCS lease sales and simultaneous filings, 1958 through 2008.

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
1958	Gubik area	BLM	1st North Slope sale	16,000	16,000?
1958	E/SE of NPR-4 & S of Mikkelsen	BLM	1st North Slope Offering	4,032,000	4,032,000 ?
1964	Between E & W segments of 1958 sale	BLM	2nd North Slope Offering	3,686,400	3,686,400
1964	East of Colville River delta	ADNR	State Sale No. 13	624,457	464,925
1965	E, S, & W of prior BLM offerings	BLM	Third North Slope Offering	8,171,000	1,095,680
1965	Prudhoe W to Colville R.	ADNR	State Sale No.14	754,033	403,000
1966	West of NPR-4	BLM	Fourth North Slope Offering	3,022,716	No leases issued
1967	Prudhoe Offshore/ Uplands	ADNR	State Sale No. 18	37,662	37,662
1969	Colville to Canning R. Offshore/Uplands	ADNR	State Sale No. 23	450,858	412,548
1979	Beaufort Sea, offshore Milne Pt. to Flaxman Island	ADNR	State Sale No. 30	341,140	296,308
1979	Beaufort Sea	MMS	BF	173,423	85,776
1980	Prudhoe Uplands, Kuparuk R. to Mikkelsen Bay	ADNR	State Sale No. 31	196,268	196,268
1982	Prudhoe Uplands, Sag. to Canning R.	ADNR	State Sale No. 34	1,231,517	571,954
1982	Beaufort Sea/Pt. Thomson	ADNR	State Sale No. 36	56,862	56,862

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
	Area				
1982	Beaufort Sea	MMS	OCS Sale No. 71	1,825,770	662,860
1982	NPRA	BLM	No. 821	~1,500,000	675,817
1982	NPRA S & SE portions	BLM	No. 822	~3,500,000	252,149
1983	NPRA Northern Portions	BLM	No. 831	2,195,845	419,618
1983	Beaufort Sea, Gwydyr Bay to Harrison Bay	ADNR	State Sale No. 39	211,988	211,988
1984	Beaufort Sea, Pitt Pt. to Harrison Bay	ADNR	State Sale No. 43	298,074	281,784
1984	Colville R. Delta/Prudhoe Bay uplands	ADNR	State Sale No. 43a	76,079	76,079
1984	Beaufort Sea	MMS	OCS Sale No. 87	7,773,447	1,207,714
1985	N. S. exempt, Canning R. to Colville R.	ADNR	State Sale No. 45a	606,385	164,885
1985	Kuparuk Uplands, S. of Prudhoe Bay	ADNR	State Sale No. 47	192,569	182,560
1986	Kuparuk Uplands, S. of Kuparuk oil field	ADNR	State Sale No. 48	526,101	266,736
1986	Mikkelsen Bay Foggy Is. Bay	ADNR	State Sale No. 48a	42,503	42,503
1987	Camden Bay: Flaxman Is. To Hulahula R.	ADNR	State Sale No. 50	118,147	118,147
1987	Prudhoe Bay Uplands, Sag. to Canning R.	ADNR	State Sale No. 51	592,142	100,632
1988	Kuparuk Uplands, Colville R. Delta	ADNR	State Sale No. 54	421,809	338,687
1988	Beaufort Sea	MMS	OCS Sale No. 97	18,277,806	1,110,764
1988	Beaufort Sea, Canning R. to Canada	ADNR	State Sale No. 55	201,707	96,632
1988	Kuparuk Uplands, Canning R. to Colville R.	ADNR	State Sale No. 69a	775,555	368,490
1988	Chukchi Sea	MMS	OCS Sale No. 109	25,631,122	1,976,912
1989	Beaufort Sea, Pitt Pt. to Tangent Pt.	ADNR	State Sale No. 52	175,981	52,463
1989	Oliktok Pt., Uplands	ADNR	State Sale No. 72a	667	667
1991	Kuparuk Uplands, Canning R. to Colville R.	ADNR	State Sale No. 70a	532,153	420,568
1991	Kavik, Sag. R, to Canning R. Uplands	ADNR	State Sale No. 64	754,452	34,143
1991	Beaufort Sea, Pitt Pt. to Canning R.	ADNR	State Sale No. 65	491,091	172,865
1991	Beaufort Sea	MMS	OCS Sale No. 124	18,556,976	277,004
1991	Chukchi Sea	MMS	OCS Sale No. 126	18,987,976	159,213
1992	White Hills, Colville R. to White Hills	ADNR	State Sale No. 61	991,087	260,550
1992	Beaufort Sea, Nuluvik to Tangent Pt.	ADNR	State Sale No. 68	153,445	0

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
1992	Kuparuk Uplands, NPRA to Sag. R. & ASRC lands	ADNR	State Sale No. 75[3]	217,205	124,832
1993	Nanushuk, N. S. foothills, Chandler R. to Ivishak R.	ADNR	State Sale No. 77	1,260,146	45,727
1993	Kuparuk Uplands, Canning R. to Kavik R.	ADNR	State Sale No. 70A-W	37,655	28,055
1993	Brooks Range Foothills, Sag. R. to Killik R.	ADNR	State Sale No. 57	1,033,248	0
1993	Colville R. Delta	ADNR	State Sale No. 75a	14,343	14,343
1995	Shaviovik, Sag. R. to Canning R., Kuparuk Uplands, Gwydyr Bay, Foggy Is. Bay	ADNR	State Sale No. 80	951,302	151,567
1996	Beaufort Sea	MMS	OCS Sale No. 144	7,282,795	100,025
1996	Colville R. offshore, State/ASRC on- & offshore	ADNR	State Sale No. 86a[3]	15,484	5,901
1997	Central Beaufort Sea, Harrison Bay to Flaxman Is.	ADNR	State Sale No. 86	365,054	323,835
1998	North Slope Areawide; North of Umiat Baseline	ADNR	State Sale No. 87	Areawide	518,689
1998	Beaufort Sea	MMS	OCS Sale No. 170	920,983	86,371
1999	North Slope Areawide	ADNR	NS 1999	Areawide	174,923
1999	Northeast portion of NPRA	BLM	991	3,900,000	864,204
2000	Beaufort Sea Areawide	ADNR	BS 2000	Areawide	25,840
2000	North Slope Areawide	ADNR	NS 2000	Areawide	652,355
2001	North Slope Foothills	ADNR	NSF 2001	Areawide	858,811
2001	Beaufort Sea Areawide	ADNR	BS 2001	Areawide	36,331
2001	North Slope Areawide	ADNR	NS 2001	Areawide	434,938
2002	Northeast portion of NPRA	BLM	2002	3,051,500	579,269
2002	North Slope Foothills	ADNR	NSF 2002	Areawide	213,374
2002	Beaufort Sea Areawide	ADNR	BS 2002	Areawide	19,226
2002	North Slope Areawide	ADNR	NS 2002	Areawide	32,316
2003	North Slope Foothills	ADNR	NSF 2003	Areawide	5,760
2003	Beaufort Sea	MMS	OCS Sale No. 186	9,459,743	181,810
2003	Beaufort Sea Areawide	ADNR	BS 2003	Areawide	36,995
2003	North Slope Areawide	ADNR	NS 2003	Areawide	210,006
2004	North Slope Foothills	ADNR	NSF 2004	Areawide	19,796
2004	Beaufort Sea Areawide	ADNR	BS 2004	Areawide	125,440
2004	North Slope Areawide	ADNR	NS 2004	Areawide	225,280
2004	NPRA Northwest portion	BLM	2004	5,800,000	1,403,561
2005	**North Slope Foothills**	**ADNR**	**NSF 2005**	**Areawide**	**55,505**
2005	**Beaufort Sea**	**MMS**	**OCS Sale No. 195**	**9,301,423**	**607,285**
2006	**North Slope**	**ADNR**	**NS 2006**	**Areawide**	**564,600**

[3] Pre-areawide sales with ASRC acreage included.

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
	Areawide				
2006	North Slope Areawide	ADNR	NS 2006A	Areawide	138,088
2006	Beaufort Sea Areawide	ADNR	BS 2006	Areawide	204,260
2006	Beaufort Sea Areawide	ADNR	BS 2006A	Areawide	29,157
2006	North Slope Foothills	ADNR	NSF 2006	Areawide	160,751
2006	NPRA Northwest Portion	BLM	2006	5,451,766	939,867
2007	Beaufort Sea	MMS	OCS Sale No. 202	8,734,194	490,492
2008	North Slope Foothills	ADNR	NSF 2008	Areawide	69,120
2008	Chukchi Sea	MMS	OCS Sale No. 193	29,389,287	2,758,408

In 1958, the first federal land was made available in the Gubic gas field area, and 16,000 acres were leased in a competitive lease sale (Table 2.2). The BLM offered more than 4,000,000 acres for leasing in two separate parcels in 1958. The larger of the two offerings abutted NPR-4 on the east and southeast and the smaller acreage package was south of the Prudhoe Bay/Mikkelsen Bay area. In 1964, the BLM held the second major simultaneous filing and drawing on 3,680,000 acres in the area between the Colville and Canning Rivers and essentially filling the area between the two segments offered in 1958.

Under the Statehood Act, the state of Alaska selected 1,616,745 acres between the Colville and Canning Rivers, north of the federal offerings of 1958 and 1964. The state subsequently offered these lands in three sales between 1964 and 1967 (Table 2.2).

In December of 1964, the state held its first North Slope lease sale, State Sale No. 13, offering 624,457 acres in the areas east of the Colville River (Jamison et al., 1980), and 196 tracts, totaling 464,924 acres, were leased (Kornbrath, 1995). This area is now the site of several large oil fields, including the Kuparuk River, Milne Point, and West Sak fields.

In 1965, federal simultaneous filings and subsequent drawings were held for approximately 8,000,000 acres in the areas to the east, south, and west of the earlier federal offerings (Jamison et al., 1980). These lands were largely in the Canning River drainage near the Sadlerochit and Shublik mountains and in the foothills areas.

During July of 1965, the state held competitive lease sale No. 14, the second on the North Slope, in the area that would ultimately include the Prudhoe Bay field. The sale offering was 754,033 acres, and 159 tracts totaling 403,000 acres were leased. Richfield-Humble acquired 28 tracts on what was to be the crest of the Prudhoe Bay field, and British Petroleum acquired 32 tracts on the flanks of the Prudhoe Bay structure.

In late 1966, the BLM offered 3,000,000 acres west of NPR-4 (Jamison et al., 1980 and Thomas et al., 1991). No leases were issued due to uncertainty arising from native land claims.

The state's third North Slope sale (No. 18) was held in January 1967, and 13 tracts were offered and issued. Richfield-Humble acquired seven tracts that covered the remainder of the crestal area of the Prudhoe Bay structure. This sale completed the leasing prior to the drilling of the discovery well at Prudhoe Bay. A total of 9,732,667 acres were leased prior to the Prudhoe Bay discovery. Presently only two of the leases acquired during the 1950s are still held by the original lessee or successor (Figure 2-3). Of the leases issued in the 1960s, including those issued after the 1969 discovery, 250 are still active (Figure 2-3).

2.3.1.2.2 Data Acquisition

The acquisition of geological and geophysical data is either concurrent with or precedes leasing activities. With the opening of the North Slope to leasing, the industry began to acquire proprietary geological and geophysical data with twin goals of better understanding the subsurface geology and hydrocarbon potential of the region. Two fundamental data sets were acquired: geological data through summer field programs and geophysical data, primarily seismic, by winter seismic operations. Jamison et al. (Jamison et al., 1980: Figure 3) provides a chart of exploration activity spanning the interval from 1958 to 1977, or the start-up of TAPS.

The first industry-sponsored geological field program was operated by Sinclair in 1958. It was a three-month program based in Umiat, in preparation for the first federal sale in September 1958. Sinclair was quickly followed by others, and an average of five to seven companies were in the field during the 1959 through 1961 seasons. A peak level of 30 geological crew-months was reached in 1961 and again in 1963. This level of geological field work was not again approached until the upsurge in activity immediately following the announcement of the discovery at Prudhoe Bay. The number of companies actively engaged in geological field work increased, and during 1962-1964, up to 10 companies were operating geological field programs. The amount of geological field work declined rapidly over the next three years, with only two to three companies in the field during the 1965 to 1967 time interval. In 1967, the year before the Prudhoe Bay discovery was announced, the geological field activity had declined to a 10-year low of two crew-months.

For the early stages of North Slope exploration there is a lack of information regarding the number of line-miles of seismic data acquired annually; therefore, the number of crew-months of seismic acquisition has been used as a gauge of activity. This number does not reveal how many permits or programs were conducted or the number of line-miles of data acquired. Therefore, the number of crew-months will be used as a gauge of activity through the mid-1970s and supplemented or replaced by the number of programs permitted and the line-miles acquired for the time intervals for which such data are available.

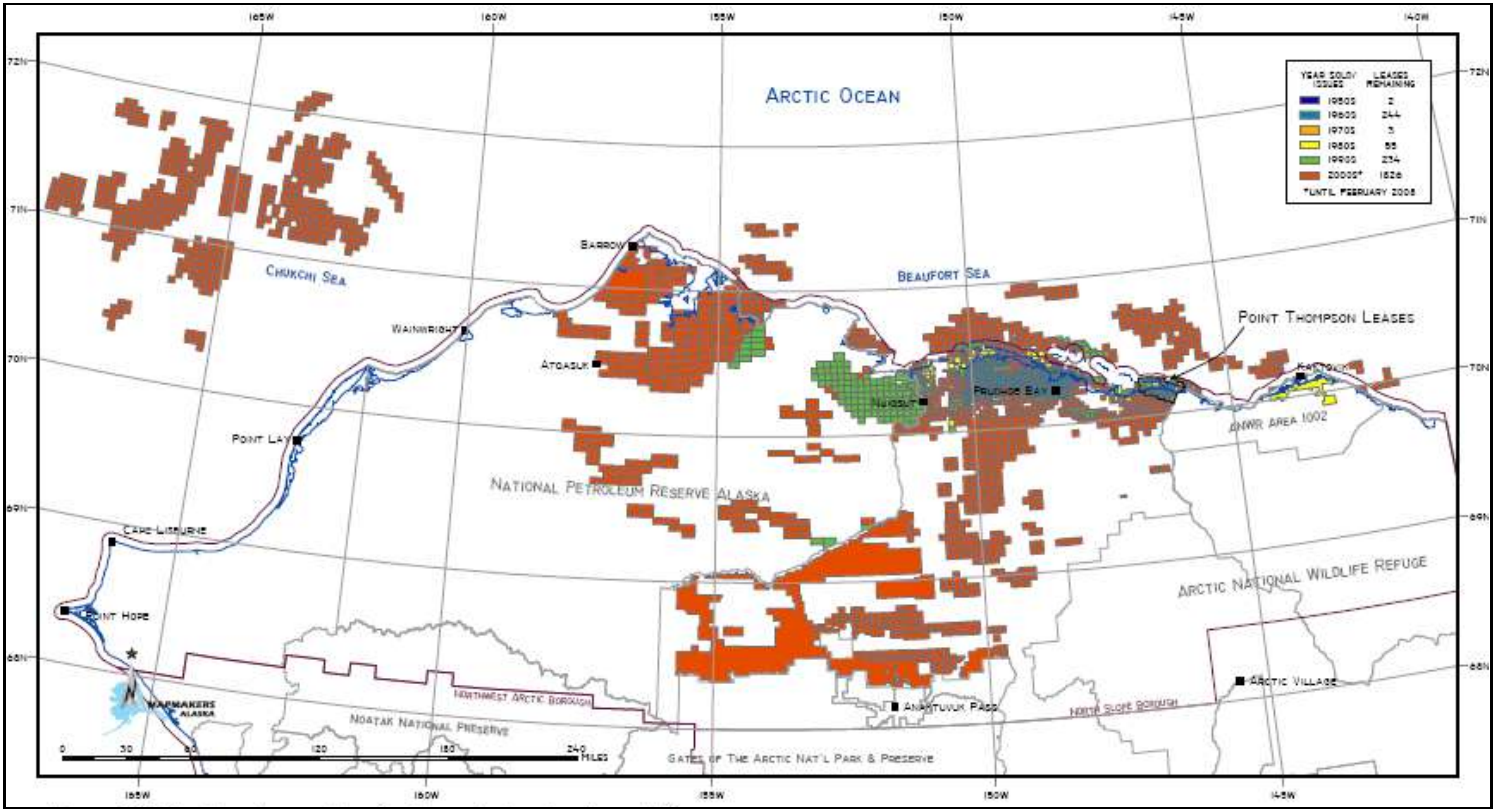

Figure 2-3. Number of currently active leases by decade of acquisition.

The Alaska Division of Oil and Gas (ADOG) records of seismic acquisition in terms of seismic permits and line-miles of seismic acquisition began in the latter half of the 1960s and were supplied by ADOG (ADOG, 2004; ADOG, 2008), summed in five-year increments. There data do not differentiate between state onshore and state offshore areas. Similarly, the MMS has records of seismic permits and line-miles of two-dimensional (2D) acquisition from 1968 to 1997 for the Beaufort Sea and from 1970 to 1991 for the Chukchi Sea. Beaufort Sea three-dimensional (3D) data exist for the interval of 1983 to 2004 and include data acquired in nearshore state waters. **A summary of the recent OCS seismic permitting activity is available on line from the MMS Alaska OCS Region website (MMS, 2008). These data from the ADOG and MMS are presented in** Table 2.3 **and** Table 2.8 to provide common sources for this information. Because of the format in which some of the information on seismic data acquisition was provided to the authors, there is a one-year difference in the way a decade of seismic acquisition is tabulated compared to the remainder of the information. For example, a seismic decade runs from 1991 to 2000 and the rest of the data are recorded as 1990 to 1999. This may result in some potential confusion; therefore the reader should keep in mind this distinction. Table 2.3 lists the 2D data and Table 2.8 summarizes the 3D data. These tables were updated in 2008 to include post-2004 acquisitions.

Sinclair and British Petroleum operated the first industry seismic program in 1962. The first seismic acquisition season consisted of 6.5 crew-months. In 1963, the total was 29.25 crew-months, and activity peaked in 1964 with 53.5 months of seismic data acquisition. There was very little seismic acquisition between 1965 and the year following the Prudhoe Bay discovery; a total of approximately 28 crew-months (Jamison et al., 1980: Figure 3). Division of Oil and Gas data **(Table 2.8)** indicate that 2,310 line-miles of onshore seismic data were acquired in the 1966 to 1970 time interval. Data from the MMS (Table 2.8**)** show that 4,151 line-miles of data were acquired in the Beaufort Sea in this same time period, probably from the shallow, state-owned portions of the Beaufort Sea. The majority of these data were acquired in 1970, post-Prudhoe Bay discovery.

Table 2.3. Tabulation of North Slope and Adjacent Beaufort Sea and Chukchi Sea 2D Seismic Acquisitions – Offshore acquisitions are both Hardwater (HW) and Marine (M).

Time Period	**Area**				
	NPRA[1] (miles)	**Colville-Canning (Includes some State Beaufort Sea (HW))[1] (miles)**	**Beaufort Sea OCS (Includes some State Beaufort Sea)[2] (miles)**	**Chukchi. Sea OCS[2] (miles)**	**1002 Area of ANWR[1] (miles)**
1966-1970	——	2,310	4,151	1,314	——
1971-1975	~5,200	5,223	6,788	4,703	——
1976-1980	~6,500	7,872	21,144	——	——
1981-1985	~1,416	15,625	45,163	32,776	1,450
1986-1990	——	8,006	12,961	37,270	——
1991-1995	——	4,960	1,298	——	——
1996-2000	——	1,104	649	——	——
2001-2007	**1,017**	**1,529**	——	**1,915**	——
TOTALS	**14,133**	**46,629**	92,154	**77,978**	1,450

1. Source – Alaska Division of Oil and Gas; 2. Source – Minerals Management Service

The marked decline in both geological and geophysical activity in the mid-1960s reflects the lack of success in the industry's exploration drilling programs through 1967.

2.3.1.2.3 Exploration Drilling

Industry-sponsored exploration drilling commenced in 1963, following five years of leasing, geological field work,, and seismic data acquisition. Eleven dry holes were drilled prior to the Prudhoe Bay discovery. The first exploration well was the Colorado Oil and Gas Company Gubik No. 1, drilled in the vicinity of the Gubik gas field. The Gubik No. 1 and the seven subsequent wells were all drilled on leases acquired in the first round of federal leasing and were located in the Brooks Range foothills within 30 miles of either the Gubik or Umiat discoveries. The initial exploration efforts were focused within or in close proximity to the areas that had shown the most promise in the Navy's exploration program. All eight wells penetrated the Cretaceous and were dry holes.

After the failure of the exploration drilling in the foothills, the industry focus shifted to the north and east. Two wells were drilled in the 1966 to 1967 interval, one each by Sinclair and Union, on acreage acquired in the first state lease sale. Both were drilled on the eastern flank of the well recognized Colville High and both were dry holes. During this same time frame the Atlantic Richfield Company (ARCO) and Humble (now part of ExxonMobil) drilled the Susie No. 1 in the northern foothills of the Brooks Range on acreage acquired in the state's second North Slope lease sale. This well was also a dry hole and presented ARCO and Humble with a critical decision: either release the rig and forego further drilling or haul the rig 60 miles to the north, during the winter, and drill in the Prudhoe Bay area. Ultimately the decision was made to move the rig and drill the Prudhoe Bay State No. 1 well.

2.3.2 Prudhoe Bay Discovery and Aftermath (1968 to 1969)

The proposed drilling site for the Prudhoe Bay State No. 1 well was on state of Alaska leases atop the Prudhoe Bay structure. The principal objective was the carbonate sequence of the Mississippian/Pennsylvanian Lisburne Group. Secondary objectives included Cretaceous sandstones and the Permian/Triassic Sadlerochit sandstones. The Lisburne carbonates were the preferred reservoir objective because of visible porosity in outcrop and the highly indurated character of the Cretaceous and Permian/Triassic sandstones observed in surface exposures.

The drilling rig was hauled north from the Susie location during the winter of 1967 and the Prudhoe Bay No. 1 was spud in April 1967. Drilling was suspended for the summer and resumed in the fall after freeze-up. ARCO and Humble announced the discovery in January, 1968. Upon completion and testing of a confirmation well, the Sag River State No. 1, seven miles to the southeast, the recoverable economic reserve estimate of 9.6 BBO and 26 TCF of gas was released.

The timing of the well and its success was very opportune, as other exploration activities had virtually shut-down at the time the Prudhoe Bay State No. 1 was drilled. In 1967, there were only three crew-months of geologic field work, no seismic programs were conducted by industry, and no drilling activity other than the Prudhoe Bay State No. 1.

2.3.2.1 Leasing

With the success at Prudhoe Bay, the state announced an additional sale in the Prudhoe Bay area, scheduled for the fall of 1969. Alaska State Lease Sale No. 23, often called "the billion dollar sale", drew widespread attention and was among the most financially rewarding sales the state has ever conducted. A total of 412,548 acres **(Table 2.2)** were leased in and around the Prudhoe Bay area. As a result of the magnitude of the discovery and to prepare for the sale, the industry greatly increased the level of exploration-related activity on the North Slope

2.3.2.2 Data Acquisition

Whereas geological and geophysical activities had declined to exceptionally low levels prior to the Prudhoe Bay discovery, they increased dramatically in 1968 and 1969. Geological crew-months increased from three in 1967 to twelve in 1968 and then to twenty in 1969. Similarly, the geophysical activity grew from zero crew-months in 1967, to twenty-four in 1968, and to ninety-seven in 1969 (Jamison et al., 1980). This activity was also reflected in the number of exploration wells drilled in this brief period.

2.3.2.3 Exploration Drilling

During the 10 years of industry activity preceding the Prudhoe Bay discovery only 11 wells had been drilled. In 1968 and 1969, 33 wells were drilled and completed (ADOG, 2000). The locations of all wells drilled in the 1960s are indicated on **Figure 2-2**. The exploration wells resulted in 12 discoveries. Most of these are now productive oil fields. Field locations are shown on **Figure 2-4**.

2.3.2.4 Discoveries

Table 2.5 was constructed to show, among other aspects, estimates of economical ultimate recovery (EUR)[5], economical remaining reserves (ERR), and original oil-in-place (OOIP) and original-gas-in-place (OGIP) for the ANS fields discovered and producing as of December 31, 2007. Table 2.6 shows fields going on production and/or additions of new, and as yet, undeveloped discoveries.

The 13 discoveries listed below in Table 2.4 were made in 1968 to 1969 (see Table 2.5 and Table 2.6). Twelve are in the general Prudhoe Bay area, along the Barrow arch trend. The thirteenth is the undeveloped Kavik gas field (Figure 2-4). The fields are listed below with cumulative production as of December 31, 2007. Total EUR for the 10 fields listed below is estimated to be 19.5 BBO (Table 2.5). Ugnu is not included in the 10 fields as it is not yet producing economically.

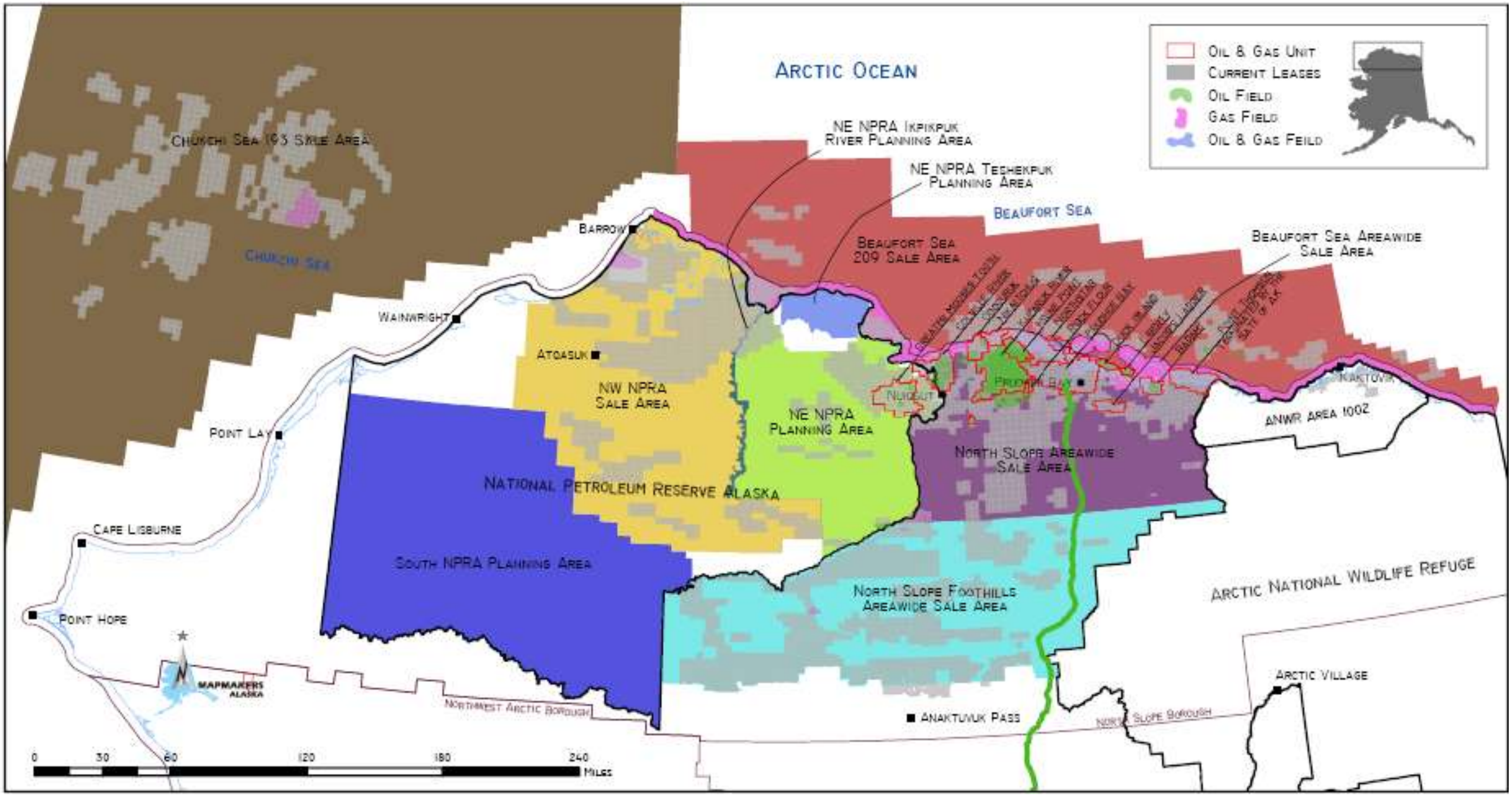

Figure 2-4. Overview of oil and gas activity – North Slope and Beaufort Sea, Alaska.

Table 2.4. North Slope oil and gas field discoveries between 1968 and 1969 (from Table 2.5 and Table 2.6)

Oil/Gas Field	Cumulative Production (December 31, 2007)
Prudhoe Bay field	**11,510 million barrels of oil (MMBO)**
Lisburne field	**165 MMBO**
Orion field	**11.4 MMBO**
Ugnu field	< 1.0 MMBO
Kuparuk River field	**2,114 MMBO**
West Sak field	**32.8 MMBO**
Milne Point field	**261 MMBO**
Borealis field	**48 MMBO**
Aurora field	**22.1 MMBO**
Polaris field	**6.5 MMBO**
Put River field	**0.5 MMBO**
Kavik gas field	**Not developed**
Gwydyr Bay field	**Not developed**

While all these fields were discovered in the 1968 to 1969 drilling seasons, the first field to be put on production, Prudhoe Bay, did not commence commercial production until 1977 and Aurora, Borealis, Orion, and Put River did not commence production until the year 2000 or later (Table 2.5). Three small fields (Put River, Qannik, and Raven) have been brought to production and three moderately-sized fields (Oooguruk, Nikaitchuq, and Liberty) are either about to come on line as producing fields or are in the development phase.

These fields are developed principally in sandstone reservoirs; the Lisburne field is the sole carbonate reservoir. The producing horizons range in age from Mississippian to Late Cretaceous, and the reservoirs represent nonmarine fluvial, deltaic, and fan environments and shallow marine shelf, bar and shoal depositional settings.

Table 2.5. North Slope oil and gas fields–producing as of December 31, 2007 or soon to start production. (Sources–Thomas, et al., 1991 and 1993; Bird, 1994; ADOG, 2003; ADOG, 2006; AOGCC[4]).

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/2007)	ERR (1/1/ 2008)	EUR[5]	OOIP or OGIP[6]
South Barrow/ Navy South Barrow No. 2	1949	Barrow Sandstone	26.0 billion cubic feet (BCF)	1950	23.0 BCF	3.0 BCF	26.0 BCF	~37.0 BCF

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[4] Alaska Oil and Gas Conversation Commission (AOGCC) Monthly Production Reports (http://www.aogcc.alaska.gov/production/pindex.shtml).
[5] ADOG (ADOG, 2006) is the source for most of EUR values.
[6] OGIP volumes labeled with a ~ are back-calculated from EUR values using an average recovery of 70%.

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/2007)	ERR (1/1/ 2008)	EUR[5]	OOIP or OGIP[6]
Prudhoe Bay/ ARCO Prudhoe Bay State No. 1	1968	Ivishak Shublik Sag River fms.	28,500 BCF	1969 (tests)	-----	26.687 BCF	26,687 BCF	41,000 BCF
			9,590 MMBO	1977	**11,510 MMBO**	**2,556 MMBO**	**14,066 MMBO**	25,000 MMBO[7]
Lisburne/ ARCO Prudhoe Bay State No. 1	1968	Lisburne	635 BCF	1983 (tests)	-----	347 BCF	347 BCF	~900.0 BCF
			400 MMBO	1985	**165 MMB0**	**79 MMBO**	**244 MMBO**	3,000 MMBO
Orion/ Kuparuk State No. 1	1968	Schrader Bluff Fm.	214 – 446 MMBO	2002	**11.4 MMBO**	**261.3 MMBO**	**272.7 MMBO**	1,200 MMBO
Put River[8]/ ARCO Prudhoe Bay State No. 1	**1968**	**Put River Sandstone of Kalubik Fm.**	**2.75-7.66 MMBO**	**2006**	**0.529 MMBO**	**2.221-7.131 MMBO**	**2.75-7.66 MMBO**	**13.7-21.9 MMBO**
Ugnu/ Sinclair Ugnu No. 1	1969	Sagavan-Irktok, Prince Creek	350-700? MMBO		0.016 MMBO	350-700? MMBO	350-700? MMBO	7,000[9] MMBO
Kuparuk River/ Sinclair Ugnu No. 1	1969	fms. Kuparuk Fm. A and C sandstones	640 BCFG	????	-----	987 BCFG	987 BCFG	~1,400 BCFG
			600 MMBO	1981	**2,114 MMBO**	**976 MMBO**	**3,090 MMBO**	5,690 MMBO
West Sak/ ARCO West Sak No. 1	1969	Sagavan-irktok, Prince Creek fms.	530 MMBO	1998	**32.83 MMBO**	**409.32 MMBO**	**442.15 MMBO**	8,000[10] MMBO
Milne Point/ Chevron Kavearak Pt. No. 32-25	1969	Kuparuk Formation	110 MMBO	1985	**206 MMBO**	**207 MMBO**	**413 MMBO**	525 MMBO
		Schrader Bluff Fm.	275 – 440 MMBO	1991	**53.3 MMBO**	**240.3 MMBO**	**293.6 MMBO**	4,000 MMBO
		Sag River and Ivishak Formations	5.8 MMBO	1995	**1.85 MMBO**	0.0(?)	1.6 MMBO	62 MMBO
Borealis/Mobil West Kuparuk State No. 1	1969	Kuparuk Formation	80-114 MMBO	2001	**43.3 MMBO**	**132.5 MMBO**	**180.8 MMBO**	195-277 MMBO
Aurora/Mobil North Kuparuk State No. 1	1969	Kuparuk Formation	51 – 67 MMBO	2000	**22.1 MMBO**	**47.5 MMBO**	**69.6 MMBO**	110 -146 MMBO
Polaris/ Mobil	1969	**Schrader**	53 – 225	1999	**6.5**	**84.9**	**91.4**	350 –

[7] OOIP for Prudhoe Bay oil (BP Exploration and ARCO Alaska, 2001)
[8] Put River production reported with PBU IPA (ADOG Annual Report 2007).
[9] OOIP for entire Ugnu accumulation ~ 15-24 BBO (McGuire and others, 2005 and Smith and others,2005)
[10] OOIP for entire West Sak accumulation ~ 11-21 BBO (McGuire and others, 2005 and Bross, 2004)

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/2007)	ERR (1/1/ 2008)	EUR[5]	OOIP or OGIP[6]
Kuparuk State No. 1		**Bluff Formation**	MMBO		**MMBO**	**MMBO**	**MMBO**	750? MMBO
North Prudhoe Bay/ ARCO N. Prudhoe Bay State No. 1	1970	Ivishak Fm.	5.3 MMBO	1993	2.1 MMBO	0.0 (?) MMBO	2.1 MMBO	12 MMBO
East Barrow/ South Barrow No. 12	1974	Barrow Ss.	12.6 BCF	1981	10 BCF	9.2 BCF	19.2 BCF	~27.0 BCF
West Beach/ ARCO West Beach No. 3	1976	Kuparuk C sandstone	1.5 – 3.75 MMBO	1993	3.6 MMBO	0.0(?) MMBO	3.6 MMBO	15 – 25 MMBO
Endicott/ Sohio Sag Delta 34633 No. 4	1978	Kekiktuk Conglom-erate	731 BCF	????	-----	979 BCF	979 BCF	~1,400 BCF
			375 MMBO	1986	**466 MMB0**	**133 MMBO**	**599 MMBO**	1,059 MMBO
Walakpa/ Husky Walakpa No. 1.	1980	Walakpa sandstone (equiv. of Alpine or Nuiqsut ?)	32 BCF	1992	**16.4+ BCF**	**163.6 BCF**	**180 BCF**	~250 BCF
Sag Delta North/ Sohio Sag Delta No. 9	1982	Ivishak Formation	7.3 MMBO	1989	**8.07 MMBO**	0.0 MMBO	**8.07 MMBO**	**16(?) MMBO**
Liberty (Tern Island)/ Shell Tern Island No. 1	**1982**	**Kekiktuk Cong.**	**150 MMBO**	**-----**	-----	**150 MMBO**	**150 MMBO**	**300(?) MMBO**
Northstar/ Shell Seal Island No. 1	1984	Ivishak Formation	210 MMBO	2001	**122 MMBO**	**88 MMBO**	**210 MMBO**	325 MMBO
Niakuk/ BP Niakuk No. 5	1985	Kuparuk C sandstone	55 MMBO	1994	**87 MMBO**	**16.8 MMBO**	**113.8 MMBO**	200 MMBO
Colville Delta/ Texaco Colville Delta No. 1A.	1985	Nuiqsut Ss.	25 MMBO	-----	-----	25 MMBO	25 MMBO	-----
Tabasco/ ARCO KRU No. 2T-02	1986	Tabasco sandstone Schrader Bluff Fm.	2 MMBO	1998	**13.75 MMBO**	**9.33 MMBO**	**23.1 MMBO**	48 – 131 MMBO
PointMcIntyr/ ARCO Pt. McIntyre (P1-02) 3	1988	Kuparuk C sandstone	300 MMBO	1993	**414 MMBO**	**197 MMBO**	**611 MMBO**	950 MMBO
Badami/ Conoco Badami No. 1	1990	Badami sandstone Canning	120 MMBO	1998	**5.20 MMB0**	55.0? MMBO	60.0? MMBO	300? MMBO

Field Name/ Discovery Well	**Disc. Date**	**Reservoirs**	**Orig. Est. of Recovery**	**Prod. Start Up Date**	**Cum. Prod. (12/31/2007)**	**ERR (1/1/ 2008)**	**EUR[5]**	**OOIP or OGIP[6]**
		Formation						
Tarn/ ARCO Bermuda No. 3	1991	Seabee Formation	42 MMBO	1998	**86 MMBO**	**74 MMBO**	**160 MMBO**	255 MMBO
Kalubik/ ARCO Kalubik No. 1	1992	Kuparuk and Nuiqsut sandstones	-----		-----	-----	OIL?	-----
Fiord/ ARCO Fiord No. 1	1992	Kuparuk A and Nechelik sandstones	50 MMBO	**2006**	**7.36 MMBO**	**55.57 MMBO**	**62.93 MMBO**	150 MMBO
Cascade/ BP Cascade No. 1	1993	Kuparuk Fm.	50 MMBO	1996	-----	50 MMBO	50 MMBO	-----
Alpine/ ARCO Bergschrund No. 1	1994	Alpine Ss.	430 MMBO	2000	**260 MMBO**	**304 MMBO**	**564 MMBO**	900 – 1,100 MMBO
Raven/ BP NK-05	**1995 (?)**	**Ivishak and Sag River Formations**	**2.8-9.3 MMBO**	**2005**	**1.623 MMBO**	**5.206 MMBO**	**6.829 MMBO**	**14 - 23 MMBO**
Midnight Sun/ BP Prudhoe Bay Unit MDS No. E-100	1997	Kuparuk C sandstone	12 – 23 MMBO	1998	**16.61 MMBO**	**10.55 MMBO**	**27.16 MMBO**	40 – 60 MMBO
Eider/ BP Duck Island Unit MPI No. 2-56/EID	1998	Ivishak Formation	3.5 – 5.0 MMBO	1998	**2.75 MMBO**	3.3 MMBO	6.0 MMBO	13.2 MMBO
Meltwater/ ARCO Meltwater North No. 1	2000	Bermuda sandstone Seabee Formation	36-64 MMBO	2001	**12.24 MMBO**	**9.24 MMBO**	**21.48 MMBO**	132 MMBO
Nanuq/ ARCO Nanuk No. 2	2000	Nanuq sandstone Torok Fm.	40 MMBO	**2006**	**0.183 MMB0**	**11.185 MMBO**	**11.368 MMBO**	150 MMBO
Nanuq Kup/ ARCO Nanuq No. 2	2000	Kuparuk C sandstone	**12-28 MMBO**	**2006**	**6.75 MMBO**	**25.615 MMBO**	**32.365 MMBO**	**21-36 MMBO**
Spark/ ARCO Spark No. ??	2000	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50 MMBO	150 MMBO
Palm/ ARCO Palm No. 1	2001	Kuparuk River Formation	35 MMBO	2003	????	35 MMBO	35 MMBO	70 MMBO
Alpine West/ Conoco-Phillips Rendezvous No. A.	2001	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50 MMBO	150 MMBO

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/2007)	ERR (1/1/2008)	EUR[5]	OOIP or OGIP[6]
Lookout/ Conoco-Phillips Lookout No. 1	2002	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50.0 MMBO	150 MMBO
Oooguruk/ Pioneer Natural Resources Oooguruk No. 1	**2003**	**Nuiqsut Sand-stone**	**70-90 MMBO**	**Mid 2008**	**-----**	**71.37 MMBO**	**71.37 MMBO**	**250-300 MMBO**
		Kuparuk C-sand.	**4.0-8.5 MMBO**	**Mid 2008**	**-----**	**4.0-8.5 MMBO**	**4.0-8.5 MMBO**	**15-25 MMBO**
Nikaitchuq/ Kerr-McGee Nikaitchuq No. 1	**2004**	**Nuiqsut Sandstone & Sag River Sandstone**	**180 MMBO**		**-----**	**180 MMBO**	**180 MMBO**	**600-700 MMBO**
Qannik/ Conoco-Phillips CD2-11	**2006**	**Qannik Sandstone**	**17.0 MMBO**	**2008**	**0.055 MMBO**	**21.386 MMBO**	**21.441 MMBO**	**79.0 MMBO**
TOTALS	**N. A.**	**N. A.**	**14,647-15,722 MMBO/** 30,575 BCF	**N. A.**	**15,687 MMBO/ 49.5 BCF**	**7,030-7,389 MMBO/ 29,176 BCF**	**22,285-22,644 MMBO/** 29,225 BCF	**61,498-62,523 MMBO[11]/** 45,000 BCF

The results of the Prudhoe Bay area discoveries and those that followed in rapid succession, plus the high level of interest in the 1969 lease sale, established the basis and direction for the next decade of exploration on the North Slope.

Table 2.6. North Slope, Alaska–Undeveloped oil and gas accumulations as of January 1, 2008 (after Bird, 1991, and Thomas et al., 1991 and 1993).

Accumulation or Field/ Reservoir Formation(s)	Year of Discovery	Estimated Technically Recoverable Resources
Umiat[12]/Nanushuk Fm.	1946	70 MMBO, 50 BCF
Fish Creek[12]/Nanushuk Fm.	1949	OIL (? MMBO)
Simpson[12]/Nanushuk Fm.	1950	12 MMBO
Meade[12]/Nanushuk Fm.	1950	20 BCF
Wolf Creek[12]/Nanushuk Fm.	1951	GAS (? BCF)
Gubik[13]/Tuluvak And Nanushuk Formations	1951	600 BCF
Square Lake[12]/Nanushuk Fm.	1952	58 BCF
E. Umiat/Nanushuk Fm.	1964	4 BCF
Kavik/Ivishak Fm.	1969	115 BCF

[11] The totals for OOIP do not include the entire potential for the Ugnu/West Sak/Schrader Bluff, when properly adjusted for volumes presented in footnotes 9 and 10 the OOIP range is 67.0 to 88.0 BBO

[12] Navy and other federally-operated wells.

[13] Pioneer Natural Resources has applied to develop several small accumulations in this area.

Accumulation or Field/ Reservoir Formation(s)	Year of Discovery	Estimated Technically Recoverable Resources
Gwydyr Bay[12]/Ivishak Fm.	1969	30-60 MMBO
Kemik/Shublik Fm.	1972	100 + BCF
Flaxman Island/Canning Fm.	1975	OIL (? MMBO)
East Kurupa/Torok-Fortress Mtn. Formations	1976	GAS (? BCF)
Pt. Thomson/Thomson Sandstone and Canning Fm.	1977	300 MMBO, **8,000 BCF**
Mikkelson/Canning Fm.	1978	OIL (? MMBO)
Hemi Springs/Kuparuk Fm.	1984	OIL (?MMBO)
Hammerhead/Sagavanirktok Fm.	1985	~200 MMBO
Sandpiper/Ivishak Fm.	1986	150 MMBO/GAS (? BCF)
Sikulik/Barrow Sandstone	1988	16 BCF
Stinson[14]/????	1990	OIL (? MMBO)
Burger/Kuparuk Equivalent	1990	14,000 BCF, 724 MMBO
Kuvlum[13]/????	1993	400 MMBO
Thetis Island[13]/Nuiqsuit	1993	OIL (? MMBO)
Sourdough[13]/?????	1994	~100 MMBO
Pete's Wicked[15]/Sagavanirktok and Ivishak Fms.	1997	OIL (? MMBO)
Sambucca[14]/Ivishak Fm.	1997	19 MMBO(?)
Tuvaaq/Schrader Bluff Fm.	2005	OIL (?MMB0)
North Shore/Ivishak Formation**	**2007**	**OIL (?MMBO)**
Tofkat/Kuparuk Formation**	**2008**	**OIL (?MMBO)**
Total		**2,155^{+} MMBO/ 26,000 – 27,000^{+} BCFG**

2.3.3 Post-Prudhoe Bay Discovery (1970 through 1989)

The focus of industry activity after 1969 was largely determined by the exploration success along the Barrow arch trend and land availability. There were no lease sales held on the North Slope or in the adjacent waters of the Beaufort Sea for a 10-year period, 1969 to 1979. This hiatus was due to the uncertainty regarding land status while ANILCA was debated and finalized. For that 10-year interval, drilling activity was confined to the areas previously leased. Commencing in 1979, the shallow state waters and the federal OCS areas of the Beaufort Sea were made available through a series of state and federal lease sales and additional onshore sales were conducted for lands in the Colville-Canning area.

In the 1980s, the federal government, through the BLM, opened most of NPRA to leasing. Although the 1002 Area of the ANWR had not been made available for leasing, there are native corporation in-holdings within the 1002 Area and in other parks and monuments. In the mid-1980s, a land trade between the federal government and several native corporations was strongly considered as a means to reduce these inholdings in the parks. At various times the ASRC has made all or portions of their land-holdings available to companies through exclusive exploration/leasing agreements.

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[14]. Discoveries that post-date the data of the Bird and Thomas and others reports
[15] Pete's Wicked accumulation will be included as part of the Gwydyr Bay development program

The discussion of the post-Prudhoe Bay activity will be parsed into five geographic areas that have different degrees of accessibility, administrative frameworks, and economic parameters. These include (1) the Colville-Canning area/state Beaufort Sea waters (ADNR and ASRC), (2) National Petroleum Reserve-Alaska (BLM and ASRC), (3) Beaufort Sea OCS area (MMS), (4) the 1002 Area of the Arctic National Wildlife Refuge (ASRC and the United States Fish and Wildlife Service (FWS)), and (5) Chukchi Sea OCS area (MMS). Any discussions regarding the administration and conduct of exploration regarding ASRC holdings will be brief due to the confidentiality of the process.

2.3.3.1 Colville-Canning Province: State and Native Lands and State Waters of the Beaufort Sea

Through the 1970s, the area between the Colville and Canning Rivers, from the Beaufort Sea south to the Brooks Range, was the only portion of the North Slope open to exploration. The bulk of the exploration activity was concentrated in the northern portion of the area, near Prudhoe Bay and to the east and west paralleling the coastline, following the structural trend of the Barrow arch.

In 1979, the state of Alaska began a leasing program in the state waters of the Beaufort Sea. This acreage is generally confined to a coastal strip three miles wide and seaward of the shoreline from Point Barrow on the west to the Canada-United States border on the east. The stated owned and administered nearshore zone is wider in the vicinity of barrier islands and major inlets.

2.3.3.1.1 Leasing

The 10 year leasing hiatus, imposed to resolve the land claims issue, concluded and sales were resumed in 1979. The first sale was a joint state/federal Beaufort Sea sale (Table 2.2). State Sale No. 30 consisted of 341,140 acres within the three-mile limit and 296,308 acres were leased. This sale marked the first major venture into offshore leasing in the Arctic by either the state or federal government and signaled the opening of a new but highly environmentally sensitive and expensive exploration province in northern Alaska. From 1979 through 1989, the state conducted a total of 18 lease sales with seven offshore (Table 2.2).

Lease sale frequency and size of the offerings have varied greatly over this period of time. There were no sales for 10 years, but three sales were held in 1988. The size of the offerings ranged from a low of 667 acres (State Sale No. 72a) to as much as 1,231,517 acres in State Sale No. 34. In the 18 sales, 6,065,494 acres were offered and 3,423,645 acres were leased. Approximately 32.5% or 1,114,184 acres were acquired in the seven offshore leases. The remaining 67.5% or 2,309,461 acres were leased in the 11 onshore sales. A significant portion of the reported total leased acres through 2005, as shown in Table 2.2, were surrendered back to the state or appropriate federal agency, and subsequently reoffered and leased again. The percentage of leases that are being recycled to the industry has not been calculated. It is entirely possible that advances in technology, changing exploration concepts, and oil prices have resulted in some tracts being leased three or more times.

Table 2.2 was not designed to provide information regarding the degree of competition for individual tracts or to reflect the number of companies or groups of companies participating in the sales. However, it is appropriate to generalize and state that the level of competition and number of participants have tended to decrease in a given geographic area over time. This may in part be reflected by the decrease in the percentage leased from the early Beaufort Sea sales (nearly 100%) to the Beaufort Sea sales in the late 1980s (~40%). Alternatively, poor exploration results and/or reduced quality of remaining acreage may be the cause of declining interest.

Native lands were not available to the industry through a competitive bidding process. The rights to explore, lease, and drill were negotiated as exclusive agreements. ASRC owns the subsurface rights to all native lands on the North Slope – for both regional and village corporation holdings.

ASRC assigned the exploration rights to several companies, at various times during the 1970s and 1980s. As a result of these agreements a total of nine wells were drilled on native lands between 1977 and 1986. This total includes the wells on native lands in NPRA, ANWR, and west of NPRA as well as those in the Colville-Canning area. The wells with the operator, year drilled, and measured depth (MD) are listed below in Table 2.7.

Table 2.7. North Slope wells drilled on native lands (for which ASCR owns the subsurface rights) between 1977 and 1989.

Operator, Well	Year Drilled	Measured Depth (in feet)
Texaco, Tulugak No. 1	1977	16,457
Chevron, Eagle Creek No. 1 (west of NPRA)	1978	12,049
Chevron, Tiglukpuk No. 1	1978	15,797
Chevron, Akuluk No. 1 (west of NPRA)	1981	17,038
Chevron, Killik No. 1	1981	12,492
Chevron, Cobblestone No. 1	1982	11,512
Chevron, Livehorse No. 1 (NPRA)	1982	12,312
Unocal, Tungak Creek No. 1 (west of NPRA)	1982	8,212
Chevron/BP, KIC No. 1 (1002 Area, ANWR)	1986	15,193

2.3.3.1.2 Data Acquisition

Following the high level of activity generated by the 1968 to 1969 discoveries, geological and geophysical crew activity decreased sharply in the early 1970s and then increased and stabilized by the late 1970s (Jamison et al., 1980). Seismic acquisition was at a post-Prudhoe high in 1970 with 96 crew-months. The acquisition level decreased to eight crew-months in 1972 and spiked again at 85 crew-months in 1975 before dropping back somewhat in the late 1970s. The ADOG data (Table 2.3) suggests that the level of activity post-1970 attained relatively high levels in the early 1970s and continued to increase until the early or middle 1980s. The data of Table 2.3 reflect this activity level but include some shallow Beaufort Sea acquisition and the Jamison et al. (1980) crew-months represent only onshore acquisition. From 1970 to 1990 more than 37,500 line-miles of 2D seismic were acquired in the shallow Beaufort Sea and within the confines of the Colville-Canning province. Much of this acquisition in the late 1970s and early 1980s was offshore and in preparation for and follow-up on acreage acquired in the joint state/federal lease sale of 1979.

There was a change in the level and mode of data acquisition after the major discoveries in the Prudhoe Bay to Colville Delta area. A major change was the introduction of 3D seismic acquisition and processing technologies to the North Slope. Three-dimensional seismic acquisition was first used on the North Slope in the early 1980s and by 1990 approximately 2,100 miles of 3D data had been acquired**.** **Table 2.8** was **constructed to document the level of 3D seismic acquisition on the North Slope and the adjacent Beaufort and Chukchi Seas.** The locations of these early data acquisitions are not known and they were possibly acquired over existing fields to better guide development and not for exploration purposes.

Table 2.8. Acquisition of 3D seismic data – North Slope and adjacent Beaufort Sea. Sources are shown in parentheses.[a]

Time Period	Area			
	North Slope Onshore[b] (ADOG and MMS)	Chukchi Sea OCS (MMS)	State Waters of Beaufort Sea (MMS)	Beaufort Sea OCS (MMS)
1981-1985	1,475 miles	-----	——	1 program (HW)
1986-1990	629 miles	-----	——	1 program (HW)
1991-1995	1,160 miles	-----	——	1 program (HW)
1996-2000	5,186 miles	-----	——	11 programs 6(M)/5(HW)
2001-**2008**	**3,136 miles**	**2,220 Sq.Miles**	**6 programs 3(M)/3(HW)**	——

a. Note that the onshore data from the ADOG does not differentiate between Colville-Canning and the NPRA or shallow Beaufort Sea hardwater acquisitions; also the information provided by the MMS did not include mileage for the 3D program **with the exception of the 2006-2007 Chukchi Sea surveys.**
b. May include both NPRA and state Beaufort Sea.

Throughout the 1980s the activity level varied but probably averaged about 20 crew-months per year. One of the major reasons for such a decrease has been the departure of several companies from the North Slope and the merger of former competitors in the late 1980s.

Geological field programs exhibit a similar profile. In the early 1970s, geological field programs averaged about 20 crew-months per year. By 1974, this had decreased to six crew-months and the activity level for the remainder of the 1970s the average was 5 to 6 crew-months per year. In the 1980s, the amount of field work varied considerably but did not reach the levels seen earlier, not even those levels of the early 1970s. Much of this was related to the emphasis on exploration and development of existing acreage positions both on and offshore.

One important aspect of geological field work is that, unlike seismic acquisition and exploration drilling, it usually takes place external to the principal area of exploration interest, where the objective intervals are exposed at the surface. Much of the geological field work has been carried out in the Brooks Range to the south and in the Sadlerochit and Shublik Mountains to the southeast in ANWR. Geologic field work was severely curtailed in ANWR by the emplacement of federal regulations in the late 1970s and 1980s.

2.3.3.1.3 Exploration Drilling

A total of 216 exploration wells were drilled during the 1970s and 1980s (Figure 2-2). This includes wells drilled in NPRA, the Colville-Canning area, in state and federal waters of the Beaufort and Chukchi Seas, and on native lands, including one within the 1002 Area of ANWR. Following the initial surge of drilling activity associated with the Prudhoe Bay discovery, the level of exploration drilling decreased substantially. The future of the pipeline was uncertain and no lease sales, offering additional drilling opportunities, were held between 1969 and 1979.

In the Colville-Canning area and state waters of the Beaufort Sea, 34 exploration wells were drilled in the five years following the 1969 lease sale. This is only one more than the 33 drilled in 1968 to 1969. An additional 33 wells were drilled during the 1975 to 1977 interval, prior to the start-up of TAPS in June, 1977 (Jamison et al., 1980). Twelve of these wells were drilled directionally from onshore pads into the shallowest portions of the Beaufort Sea. Between the opening of the pipeline in 1977 and the end of the 1980s, exploration became more wide spread and 81 wells were drilled in the shallow Beaufort Sea and across the Colville-Canning province.

Offshore drilling from ice or gravel islands and large ice-resistant drilling vessels in state waters did not commence until after the 1979 lease sale. Between 1980 and the end of 1989 there were a total of 29 wells drilled in the state waters of the Beaufort Sea.

2.3.3.1.4 Discoveries

From 1970 through 1989 there were 17 discoveries in the Colville-Canning area and the state Beaufort Sea waters (Table 2.9). Ten were onshore and six were either entirely or partially in state waters of the Beaufort Sea. The seventeenth discovery, at Seal Island No. 1 (now Northstar), was on joint state-federal acreage. Nine of these discoveries have produced or are currently producing economic quantities of oil and two will be developed in the near future (Point Thomson and Colville Delta). **The discoveries are summarized in Table 2.5 and Table 2.6 and listed below with cumulative production as of December 31, 2007.**

Table 2.9. North Slope oil and gas discoveries between 1970 and 1989 (from Table 2.5 and Table 2.6).

Oil/Gas Field	Cumulative Production (December 31, 2007)
North Prudhoe Bay	**2.1 MMBO**
Kemik Gas Field	not developed
Flaxman Island	not developed
West Beach	3.6 MMBO
East Kurupa Gas Field	not developed
Point Thomson Gas/Condensate (light oil)	not developed
Endicott	**466 MMBO**
Mikkelsen	not developed
Sag Delta North	**8.1 MMBO**
Northstar	**122 MMBO**
Hemi Springs	not developed
Niakuk	**87 MMBO**

Oil/Gas Field	Cumulative Production (December 31, 2007)
Colville Delta	not developed
Tabasco	**13.8 MMBO**
Point McIntyre	**414 MMBO**
Badami	**5.2 MMBO**
Stinson (?)	not developed

The nine producing fields have EUR of 1.63 BBO. Endicott and Point McIntyre are both expected to produce more than 500 MMBO.

Point Thomson is a large field, with a long and troublesome history. A study, recently commissioned by the ADNR (ADNR, 2008), provided an original gas in place (OGIP) estimate of 8.5 to 10.4 TCF, with original condensate in place of 490 to 600 million barrels of condensate (MMBC), and OOIP of 580 to 950 MMBO in the oil rim. The study suggests that under ideal conditions, with gas cycling and extended production of condensate and oil prior to gas blowdown (30 years with 22 producing wells and 8 injection wells), the field could produce as much as 420 to 515 MMBCF and 290 to 475 MMBO. The technically recoverable gas reserves produced under a scenario similar to the one above would be about 5.9 to 7.3 TCF. If blowdown were to occur early in the history of the field development, the models suggest that recovery of condensate and oil could be as low as 127 to 156 MMBC and 30 to 150 MMBO, but gas recovery would be in the 6 to 7 TCF range over a period of 12 to 15 years (ADNR, 2008). Additional scenarios were run with varying numbers of producing and injection wells, for periods of 10 and 20 years before blowdown, and results shown production ranges of: (1) 10 years of cycling – 300 to 370 MMBC, 225 to 370 MMBO, and 4.8 to 5.9 TCF, and (2) 20 years of cycling – 370 to 450 MMBC, 250 to 400 MMBO, and 4.8 to 5.9 TCF.

The findings appear to be optimistic and open to question, especially with respect to the recovery predicted for oil from the oil rim. The summary of findings (ADNR, 2008) cites the oil having American Petroleum Institution (API) gravity as high as 18°. This is the same range of API gravity as the heavy oil being produced from the West Sak and Schrader Bluff reservoirs, and recoveries are not projected to be more than 5 to 10%. The API gravity at the Kuparuk West Sak pool ranges from 22° to 10°, increasing with depth (temperature) and at the Milne Point Schrader Bluff pool it ranges from 22° to 16°. Thus a more realistic value for the oil rim at the Point Thomson field may be 58 to 95 MMBO, not the 290 to 495 MMBO theorized in the PetroTel study performed for ADNR. The Point Thomson owners "don't believe the recovery of this heavy oil will be more than 5% --- nowhere near 50" (PN, 2008). They further state that "the oil rim is thin, discontinuous, and heavy oil --- molasses."

It is doubtful the field will be developed before a gas pipeline is approved and well-along in the construction phase. The potential for satellite development in the area and addition post-1980s discoveries should provide the necessary incentive to proceed.

In the spring of 2007, the state of Alaska dissolved the Point Thomson Unit and revoked the leases (PN, 2007). The former lease-holders filed lawsuits appealing the state's decision (PN, 2007c). In late 2007, the Alaska Superior Court directed the state to hold an additional hearing to consider whether terminating the unit was an appropriate remedy for the lease-holders failure to fulfill their obligation to develop the reservoir (PN, 2008p). The lease-holders are continuing in discussion with the state to resolve these issues. Although the state has terminated the Point Thompson Unit, the former unit operator (ExxonMobil) announced plans to drill on it's leases at Point Thompson during the 2008-09 winter drilling season in order to delineate the reservoir and bring it on line by 2014 (PN, 2008q). ExxonMobile applied for the necessary permits to drill two wells on two leases and began mobilizing for a winter exploration program (PN, 2008r). The state has authorized processing of the permits on two "conditionally reinstated" leases providing that ExxonMobil make an unconditional funding commitment to drill and produce from these wells by 2014 (PN, 2009). Thus, at least the near-term fate of this field is unknown.

For this addendum report, it is conservatively assumed that the gas reserves are 8.0 TCF and the liquids are estimated to be at least 300 MMBC (Table 2.6). Thus, the recoverable gas at Point Thomson accounts for about 20 to 25% of the proven gas reserves on the North Slope and the development and production of this gas potentially has impact on the construction and start-up of the much sought-after gas pipeline.

2.3.3.2 National Petroleum Reserve-Alaska (NPRA)

The decades of the 1970s and 1980s were highlighted by a variety of programs and 3 activities in NPRA. The federal government undertook a second episode of exploration, NPRA was opened-up to industry exploration and leasing for the first time, and ASRC made some of its inholdings available to industry for exploration.

Prior to the start-up of this new exploration program and during the relative lull in activity between formal exploration efforts, the U. S. Navy drilled eight development wells in the Barrow gas field for local use. Additionally a shallow exploration well was drilled at Iko Bay. This work was not considered part of the expanded exploration program (Schindler, 1988).

A small gas accumulation was discovered at East Umiat in 1963. The production is from sandstones in the Nanushuk Group at 1,800 to 3,000 feet depth. There has been no estimate of recoverable reserves and the trapping is structural in nature (Bird, 1981). As a result of the Navy's drilling efforts in the Barrow area, the East Barrow gas field was discovered in 1974. It produces from the Jurassic Barrow sandstone at 1,900 to 2,100 feet depth. The estimated recoverable reserves are 19.2 BCF, and the trap is also structural in origin (Bird, 1981).

2.3.3.2.1 USGS/Husky Exploration Program – 1974 through 1982

The Organization of Petroleum Exporting Countries (OPEC) oil embargo caused the U. S. Congress to allocate funding to develop Elk Hills Petroleum Reserve and explore NPRA, due to concern that a long-term shortage of oil might develop. This initial funding level of $7.5 million for NPRA (Schindler, 1988) later grew to many times that modest amount and a seven-year program evolved.

The second phase of NPRA exploration commenced with the Cape Halkett No. 1 well in 1975 and ended six years later with the Koluktak No. 1 well in 1981. During this interval 28 wells were drilled (Weimer, 1987, and Schindler, 1988). These wells represent a total of 283,869 feet of exploration drilling.

To support this drilling an extensive multi-year seismic acquisition program was initiated and completed. The result was a large grid that provided government geologists with a better framework within which they could more scientifically locate the exploration wells. Based on the existing literature the precise number of seismic line-miles acquired is uncertain. The number of line-miles reported ranges from 12,300 (Banet, 1991) to 13,179 (Schindler, 1988), and 14,770 (Weimer, 1987). Schindler (1988) lists seismic acquisition by year and the others simply provide a total figure. Thus, Schindler's figures are believed to be more accurate. They are also in close agreement with the 13,116 line-miles acquired between 1972 and 1982, as cited by ADOG and included in Table 2.3.

The 28 wells were principally situated along the Barrow arch with a strong emphasis on play types recognized in the productive Prudhoe-Kuparuk area to the east. The 28 wells tested 26 different objectives. The two exceptions were the Walakpa No. 2 and East Simpson No. 2 wells which were drilled on the same features as the Walakpa No. 1 and East Simpson No. 1 wells respectively. Only 4 of the 28 wells were drilled south of 70° north latitude **(Figure 2-2)**; therefore, the bulk of NPRA was not evaluated by the drill during this exploration phase.

Weimer (1987) summarizes the wells in a tabular format and Schindler does a similar treatment in narrative text. While Schindler provides more detail, the Weimer treatment is easier to use. Well depths range from 3,666 feet (Walakpa No. 1) to 20,335 feet (Tunalik No. 1). Two wells (Tunalik No. 1 and Inigok No. 1) exceed 20,000 feet and 11 wells have a total depth between 10,000 and 20,000 feet. Eleven wells fall into the 5,000 to 10,000 foot depth range and two wells are shallower than 5,000 feet. For a convenient reference the wells are grouped below, by primary drilling objective(s). In the listing below (Table 2.10), the wells are generally arranged in stratigraphic succession from older to younger exploration horizons:

Table 2.10. NPRA exploration wells (from Weimer, 1987, and Schindler, 1988).

Target Horizon(s)	Well Name
Lisburne/Kekiktuk	Ikpikpuk No. 1
Lisburne	Lisburne No. 1
Ivishak/Lisburne	W. T. Foran No. 1, Drew Point No. 1, Kugrua No. 1, Inigok No. 1, Tunalik No. 1, and J. W. Dalton No. 1
Ivishak	Cape Halkett No. 1, East Teshekpuk No. 1, South Harrison Bay No. 1, East Simpson No. 1, East Simpson No. 2, and South Meade No. 1
Sag River Sandstone	West Dease No. 1
Kingak sandstones/Ivishak	South Simpson No. 1
Simpson sandstone (Jurassic)	Walakpa No. 1, Kuyanak No. 1
Jurassic "bar sandstone"	North Inigok No. 1

Walakpa Ss/Simpson Ss/Barrow Ss/Sag River Ss	Tulageak No. 1
Walakpa Ss/Simpson Ss	Walakpa No. 2
Neocomian Ss/Jurassic Ss/Lisburne	Peard No. 1
Kuparuk/Ivishak	Atigaru Point No. 1, West Fish Creek No. 1
Kuparuk	North Kalikpik No. 1
Torok Ss/Fortress Mountain	Seabee No. 1, Awuna No. 1
Nanushuk sandstone	Koluktuk No. 1

From this list of drilling targets it is obvious that the Prudhoe-Kuparuk play types dominated the drilling program. Twenty-one of the 28 wells targeted Prudhoe-Kuparuk area reservoirs. No oil discoveries resulted from the 28-well program, but favorable oil shows (Lisburne No. 1 well), ubiquitous gas shows, and a gas discovery at Walakpa (180 BCF) indicate that hydrocarbons are present throughout he area. A very robust gas show at the North Inigok No. well (30 million cubic feet per day (MMCFPD) on a drill stem test) with 27% ethane through pentane plus, suggests the existence of a down-dip oil accumulation.

The drilling program ended when the Koluktuk No. 1 was plugged and abandoned in April 1981. The drilling resulted in the discovery of two gas fields **(Table 2.5)** and evidence of oil potential as far south as the location of the Lisburne No. 1 well, in T11S and R16W, near the southern boundary of NPRA. With a reestablishment of the NPRA boundary, the Lisburne No. 1 well now lies outside NPRA **(Figure 2-2).**

2.3.3.2.2 Industry Activity, Early-Middle 1980s

After the completion of the second round of federally-sponsored exploration in NPRA, the government elected to open NPRA to leasing and encouraged industry exploration. The second phase of federal exploration did not yield any significant discoveries but did provide a wealth of information for future operations.

Leasing: The federal leasing program in NPRA was administered by the BLM and commenced in 1982 with two lease sales (Nos. 821 and 822) in January and May **(Table 2.2)**. A total of 271 tracts with 5,035,722 acres were offered in the two sales. Most of the acreage was located in the southern and southeastern portions of NPRA. Between the two sales, 38 tracts with a total of 927,966 acres were leased. In both sales, the leasing tended to be focused in three areas: (1) west of Nuiqsut, (2) west of Umiat, and (3) west of the Lisburne No. 1 well. This leasing activity was probably directed at Umiat style plays or at least Cretaceous, perhaps Kuparuk, objectives.

The third sale (No. 831) was held in July 1983 with an offering of 84 tracts totaling 2,195,845 acres scattered across the northern portion of NPRA. Twenty tracts, with a total of 419,618 acres **(Table 2.2)**, were leased and appear to have been selected to evaluate Prudhoe Bay area play-types. The leases were largely concentrated in the area between Admiralty Bay and the Chukchi Sea. A fourth sale was scheduled for July 1984 (No. 841), but when no bids were submitted the sale and future lease sales were cancelled. This brought leasing to a close until late in the 1990s.

Data Acquisition: Prior to the sales, the industry conducted no new geological or geophysical data acquisition programs. The industry relied almost exclusively on the existing geological surface work, their proprietary geological field programs, and the publicly available USGS reports. Similarly, the existing federally acquired seismic data base was reprocessed and reinterpreted in lieu of conducting proprietary industry seismic acquisition programs.

Exploration Drilling: One well was drilled within NPRA as a result of this short-lived leasing program. The ARCO Brontosaurus No. 1 was drilled to a depth of 6,660 feet in 1985. The target was the updip, onlap wedgeout of the Ivishak Sandstone onto the Barrow arch. The well was plugged and abandoned (Weimer, 1987). A second well was drilled by industry inside the boundaries of NPRA on native corporation inholdings. The Chevron Livehorse No. 1 was drilled in 1982 to a total depth of 12,312 feet. It too targeted the Ivishak Sandstone and was a dry hole (Weimer, 1987).

Discoveries: The brief exploration drilling effort did not result in a discovery and the area was abandoned by the industry and remained dormant until the late 1990s, when the industry's interest was rekindled by the Alpine discovery, just to the east of NPRA in the Colville Delta area.

2.3.3.3 Beaufort Sea – Federal OCS

The OCS area of the Beaufort Sea was unavailable to the petroleum industry until the joint state/federal lease sale of 1979. This and subsequent sales provided access to waters beyond the three-mile limit, extending from Point Barrow on the west to the United States-Canada border on the east. The original assessment area included deep water regions and totaled 34,430 square miles (Sherwood et al., 1995). As treated in this report, the prospective area consists of the OCS portion of the Beaufort Sea shelf and encompasses approximately 12,160,000 acres or 19,000 square miles (Sherwood, 2005).

2.3.3.3.1 Leasing

Four lease sales were held in the OCS portion of the Beaufort Sea between 1979 and 1990 **(Table 2.2)**. A total of 28,050,266 acres were offered in these sales, ranging from a low of 173,423 acres in 1979 (Sale BF) to a high of 18,277,806 acres in 1988 (OCS Sale 97). That total includes previously unoffered acreage, reoffering of surrendered leases, and reoffering of previously offered but unleased acreage. The leased acreage totaled 3,067,114 acres with more than 75% of that leased in OCS sales 87 and 97 **(Table 2.2)**. However, leased acreage as a percentage of offered acreage was much higher in the earlier sales where nearly 49% of the acreage offered in Sale BF was leased, and in OCS Sale 97 only 6% was leased. This latter sale was an areawide sale, and this leasing approach now appears to be the standard practice for OCS sales in Alaskan waters.

OCS Sale No. 71 included the leasing of the acreage that comprised the basis for the Mukluk prospect. The structure is located in Harrison Bay, is approximately 170,000 acres in size, and was leased for total high bids exceeding $1.5 billion, with the highest single bid of $227 million for one 5,700-acre tract on the crest of the structure. This feature and the money invested in it eventually proved to be the biggest financial disappointment in the history of exploration on the North Slope and the adjacent waters of the Beaufort Sea.

2.3.3.3.2 Data Acquisition

The data acquisition process is different in the OCS regions. There is generally little, or more commonly, no geological field work conducted exclusively for the purpose of better understanding the subsurface geology of the offshore region. Rather, the subsurface well control resulting from the onshore drilling activity and, secondarily, outcrop geology is tied into the seismic grids to extend the existing geologic framework into the offshore areas and assist in the definition of potential prospects.

Seismic acquisition in the Beaufort OCS commenced in 1970 and continued through out the region until 1997, but only 1,947 miles of the total of 91,915 miles of 2D seismic data were acquired post-1990 **(Table 2.3)**. Some portion, of the approximately 90,000 miles of seismic data, was acquired within state waters. The portion that occurred within state waters was not made available to the authors of this report, at least in part because of confidentiality regarding proprietary acquisition by the various lease/data owners.

Seismic acquisition has involved both summer marine and winter hardwater (on ice) programs. A total of 194 2D permits were issued from 1970 through 1989 with 123 for marine and 71 for hardwater programs. The area of acquisition extends from near Point Barrow on the west to the United States-Canada border on the east.

The acquisition of 3D seismic data began in 1983 and only one permit was granted and completed by the end of 1989 **(Table 2.8)**. This was a hardwater program and was probably acquired in the vicinity of existing production to enhance development of known reserves.

2.3.3.3.3 Exploration Drilling

Drilling in the Beaufort Sea OCS commenced in 1981 with the Beachy Point No. 1, and through 1989 a total of 20 wells had been drilled in the OCS portion of the Beaufort Sea. The 20 exploration wells tested 14 individual prospects. Five of the 14 prospects (9 wells) were determined, by the MMS, to be capable of producing hydrocarbons. The drilling peak was in 1985 to 1986 when 11 of the 20 wells were drilled. Drilling quickly decreased after this peak, and only one well a year was drilled from 1987 to 1989.

Among the dry holes was the Mukluk No. 1 well. Prior to drilling, the Mukluk structure was thought to have recoverable reserves in the range of 1.5 to 10.0 BBO. The well was drilled in 1983 from a man-made island 350 ft in diameter erected in 48 ft of water. At a cost of $120 million, the Mukluk well retains to this day the dubious distinction of being the most expensive dry well ever drilled.

Depending on water depth, the OCS exploration wells are either drilled from an artificial island or large, heavy, usually bottom-anchored drilling structures. Through 1990, 10 wells were drilled from gravel islands, 1 from an ice island, and 9 from drilling rigs such as the Glomar Beaufort Sea CIDS or the Canmar Explorer II. If a commercial discovery is made and the field developed, a larger more permanent structure is built to provide the base for long-term operations.

2.3.3.3.4 Discoveries

Four of the five prospects deemed capable of production (MMS, 2001) have been termed significant discoveries by both the MMS (2001) and ADOG (2000). Three of these are completely in OCS waters and are the Hammerhead, Sandpiper, and Tern/Liberty (Table 2.13). The fourth discovery is the Northstar field (Seal wells) that underlies both state and federal acreage **(Table 2.5)**. The first OCS discovery was Tern (Liberty) in 1983, followed by Seal/Northstar in 1984, Hammerhead in 1985, and Sandpiper in 1986.

Water depths range from as little as 21 ft at Liberty to as much as 103 ft at Hammerhead. These depth variations dictate both the type of basic exploration drilling structure to be utilized and the type of production facility that would need to be built. The costs escalate significantly with incremental increases in water depth. Three of these discoveries Liberty, Sandpiper, and Northstar lie offshore from the well-established Kuparuk and Prudhoe Bay oil fields and their infrastructure. The Hammerhead discovery lies 50 to 60 miles east of Prudhoe Bay field and 15 to 20 miles north of Point Thomson in relatively deep water.

The Northstar field has been developed and production began in late 2001 **(Table 2.5)**. After BP Alaska suspended plans to develop the Liberty field in 2002, it has determined to proceed with a Memorandum of Understanding (MOU) with the MMS that could lead to final approval of the plan of development and depletion in late 2007 (PN, 2004). Development of the Sandpiper discovery will probably occur when and if the recent discoveries in the Gwydyr Bay and offshore Kuparuk areas are developed. **BP Alaska sanctioned the development of Liberty in 2008 (PN, 2008c) and will drill the first well, a 40,000 ft extended-reach horizontal well, from the Endicott pad.**

Development of the Sivulliq discovery (formerly Hammerhead) has been thought to be largely dependent upon establishment of commercial oil production in the Point Thomson-Flaxman-Sourdough area, but the recent acquisition of Beaufort Sea acreage by Shell and the purchase of two vessels capable of drilling on the Sivulliq structure (PN, 2006) significantly alters that perception. In August 2007 MMS approved Shell's Beaufort Sea exploration plan, but a lawsuit was filed by several ANS groups, and in August 2007 an injunction was placed on Shell's Beaufort Sea drilling activities by the 9th Circuit Court of Appeals pending court review of the case (PN, 2007g). In November 2008 the court issued a decision requiring MMS to prepare a revised environmental assessment of Shell's Beaufort Sea exploration plan and denied a request by Shell to lift the injunction on the company's Beaufort Sea drilling (PN, 2008s). Shell plans to appeal the court's decision and has announced plans to defer its 2009 Beaufort Sea drilling program that includes both the Beaufort and Chukchi seas until 2010 and 2011, given a favorable resolution of the current litigation (PN, 2008t).

2.3.3.4 1002 Area of Arctic National Wildlife Refuge (ANWR)

The Arctic National Wildlife Range, now the Arctic National Wildlife Refuge, was established in 1960 and originally contained 9,000,000 acres. The ANILCA legislation of 1980 more than doubled ANWR to approximately 19,000,000 acres and designated 9,000,000 acres as wilderness (not the 1002 Area). Approximately 8% of ANWR or 1,500,000 acres were set aside, as the "1002 Area", for special study of the regions fish and wildlife values, as well as it hydrocarbon potential. The authors of that study ultimately concluded that the area had enormous hydrocarbon potential and recommended that the area be opened to exploration and leased by competitive bid, subject to prudent environmental safeguards and controls. The area has not been opened for exploration since that time and can only be opened through an act of congress and with the president's concurrence.

The 1002 Area of ANWR extends from the Canning River on the west to the Aichilik River on the east and from the approximate 1,000 ft contour on the south to the Beaufort Sea/Kaktovik Inupiat Corporation lands on the north. The Kaktovik Inupiat Corporation selected lands within the Arctic National Wildlife Range following the 1971 passage of ANCSA. This inholding is located along the Beaufort Sea coast in the vicinity of Barter Island and is comprised of 92,160 acres.

The 1002 Area of ANWR has long attracted the interest of the petroleum industry. There are active oil seeps, exposures of oil-stained sandstone, and large attractive structures. Oil-prone source rocks are present both in outcrop and in the subsurface – as confirmed by wells along the refuge boundary, and hydrocarbon accumulations occur to the west (Point Thomson), north (offshore at Kuvlum), and east (Canadian Beaufort /Mackenzie delta).

2.3.3.4.1 Federal Lands

The approximately 1,500,000 acres of federal land within the 1002 Area are administered by the FWS. Since the passage of ANILCA, the area has been the subject of two hydrocarbon resource evaluations by the USGS, experienced a two-season long seismic acquisition program, flanked by exploration drilling on the west, north, and east, and seen an unsuccessful attempt to complete a land-trade with several native corporations.

Leasing: There has been no leasing within the 1002 Area. However, there was an attempt to execute a land-trade with several native corporations that had significant inholding within national parks or other wilderness areas. In the mid-1980s, it was proposed that these corporations would trade these inholdings for lands of "equal" value within the 1002 Area. Six corporations were found qualified to participate and each formed a partnership with one or more major oil companies. The industry partners were to supply the technical expertise and in return have the exclusive right to explore any lands acquired by the native corporation partner.

The federal government proposed and developed a tract selection/land-trade process, and the native corporations and industry partners proceeded to bid on 71 complete or partial tracts. These tracts were 4-square mile parcels (2,560 acres) and the bidding indicated interest in 8 to 10 prospects. As a point of interest, virtually all the tracts that received bids were either along the trend of the Marsh Creek anticline or to the east of it. All areas of interest were within the deformed portion of the 1002 Area. This largely conforms to the findings of the 1987 USGS

(Dolton et al., 1987) evaluation but is in sharp contrast to the conclusions reached by the USGS in their 1998 assessment (Bird and Houseknecht, 1998). This proposed land trade was never carried through to the point of completion and the lands were never transferred.

Data Acquisition: The ANWR has a long history of geological study and mapping. The first geologic mapping was by Leffingwell in 1919. He reported oil seeps and oil-stained rocks within what is now ANWR and established the general stratigraphic sequence as it is known today. Industry-sponsored field work was sparse until after the discovery of Prudhoe Bay. In 1969, at least eight companies participated in field programs of varying duration and completeness. A minimum of 20 to 25 crew-months of geologic mapping and evaluation were logged in 1969. Subsequently geological programs varied from less than a crew-month to five to six crew-months throughout the 1970s and 1980s.

Geophysical activity within the 1002 Area has historically consisted of the less invasive, but limited value, gravity and magnetic surveys. The only seismic acquisition within ANWR occurred during two successive field seasons in 1984 and 1985 under federal oversight. A 22-company consortium shared the costs of acquisition and processing. These two seasons produced approximately 1,450 line-miles of data (Table 2.8). The data were of mostly poor to moderately good quality.

Exploration Drilling: There has been no exploration drilling on federal lands within the 1002 Area or any other federally controlled portion of ANWR. However, the area is surrounded on all sides, except to the south, by exploration wells drilled on state, native corporation, federal OCS, and Canadian OCS acreage. At least 40 wells have been drilled within 20 miles of the 1002 Area. These wells have found at least six oil and (or) gas accumulations.

Discoveries: With no exploration drilling there have been no discoveries. However, both the Point Thomson and Flaxman Island accumulations are in extremely close proximity to the 1002 boundary and there is a remote chance that one or both may extend beneath the 1002 Area. An additional discovery, Sourdough, was made in the 1990s and almost certainly extends into the 1002 Area.

2.3.3.4.2 Native Corporation Lands

The Kaktovik Inupiat Corporation acreage has offered opportunity for exploration within the boundaries of ANWR. While KIC owns the surface rights, the subsurface domain is owned by the ASRC. ASRC entered into an exploration agreement with Chevron and British Petroleum that granted them exclusive exploration rights to these lands. Consequently, Chevron and BP Alaska drilled the KIC No. 1 well in 1986. The results of that well have been held confidential to this time and nothing is known about the stratigraphy or hydrocarbon potential of the section encountered in the well. In an attempt to replicate the stratigraphy that may have been observed in the KIC well, an industry consortium drilled the Tenneco Aurora well in 1988 on an OCS lease. The Aurora well is located about 6 miles east-northeast of the KIC well. The results were mixed and did not provide the consortium with reliable answers to the questions regarding the stratigraphy and hydrocarbon potential of the KIC well.

2.3.3.5 Chukchi Sea – Federal OCS

The Chukchi Sea is situated north of the Bering Straits, between the western North Slope and eastern Siberia. This area was long ignored because of the extreme remoteness, high cost of operation, and extensive ice cover. There is no infrastructure, no major population centers, and no year around, reliable transportation network/system. Given these negatives any potential hydrocarbon accumulation would have to be very large and oil (gas) prices would have to be high and sustainable.

In the early to middle 1980s, factors appeared to favor the possibility that the Chukchi Sea had large resource potential and long-term pricing would support exploration in this hostile environment. Consequently, the MMS began to evaluate the level of industry interest and ultimately determined that there was sufficient interest to proceed with a leasing program in the Chukchi Sea. A good summary of the Chukchi Sea OCS is presented in Sherwood et al.. (1998b). The 1995 assessment area covered 44,580 square miles or more than 28,500,000 acres (Sherwood et al., 1995). The Chukchi Sea assessment area has since been reconfigured, and the shelf portion of the area is now 41,280,000 acres or approximately 64,500 sq. miles (Sherwood, 2005).

2.3.3.5.1 Leasing

Two areawide lease sales have been held in the Chukchi Sea. The first sale, OCS Sale 109, was held in 1988. The MMS offered more than 2,500,000 acres in the only sale held during the 1970s and 1980s, and tracts totaling 1,976,912 acres were leased **(Table 2.2)**.

2.3.3.5.2 Data Acquisition

Once again, because of the offshore nature of the offerings there were no geological programs conducted to provide information for the sales. Rather, the seismic programs were designed to provide ties from the geology of the few relatively proximal onshore wells and previously studied exposures in NPRA and the areas west of NPRA, to the offshore seismic grids.

A modest amount of seismic data had been acquired in the Chukchi Sea prior to 1970. Nearly 5,000 line-miles of 2D seismic data were acquired in the early 1970s (Table 2.8). However, the pace of seismic acquisition increased greatly with the knowledge of pending lease sales, and 69,185 line-miles of data were acquired during the 1980s **(Table 2.3)**. With the exception of a single hardwater program in 1986 all the data were acquired in open water conditions during the summer.

2.3.3.5.3 Exploration Drilling

During 1989, The Klondike No. 1 well was drilled in the Chukchi Sea by Shell on leases acquired in OCS Sale 109. The well was drilled with the drillship Explorer III in a water depth of 141 ft. The Klondike well had oil shows in the Shublik/Fire Creek (uppermost Sadlerochit), Kuparuk, and Brookian turbidites near the base of the Torok. While this was the only well to be spud and completed in the 1980s, four additional wells were drilled in the 1990s.

2.3.3.5.4 Discoveries

The Klondike No. 1 well did not yield a discovery, but it did have good shows in three highly prospective intervals, all of which are productive in the Colville-Canning area.

2.3.4 Recent Activity (1990 through 2007)

The interval from 1990 to the present has provided a new chapter in exploration in northern Alaska that includes additional offshore discoveries and development, Jurassic, Alpine-style discoveries near and within NPRA, new emphasis on smaller satellite fields, development of the heavy oil deposits of West Sak and Schrader Bluff, gas as a viable exploration objective, and the growing role of intermediate to small companies as active bidders and explorers on the North Slope. **For the lion's share of the discussion, the time interval of interest in this section ends December 31, 2007. But in the interest of completeness the interval is extended through the first part of 2008 in some circumstances to accommodate recent leasing developments in the Chukchi Sea.**

The decline of the older large fields of the Prudhoe Bay area has resulted in an increased emphasis on enhanced recovery techniques, extended-reach horizontal drilling technology, and 3D seismic data to maximize the recovery from these fields. The presence of the established infrastructure and the spare capacity at the major fields has also contributed to an emphasis on exploration for and development of satellite fields. Small fields with only a few tens of MMBO are now being developed, if they are easily accessible from existing infrastructure. Tabasco and Midnight Sun **(Table 2.5**) are prime examples. Older, previously ignored, accumulations such as North Prudhoe Bay and West Beach that were discovered in the early to mid-1970s have been developed and brought on production in the late 20th Century and early 21st Century **(Table 2.5**).

The potential associated with the construction of a gas pipeline from the North Slope to either the Midwest through Canada or to an ice free port at Valdez with the possibility of a bullet-line to the greater Anchorage/Kenai area has created a great deal of interest in natural gas exploration. This gas-related exploration emphasis has largely been reflected in State of Alaska's Foothills areawide lease sales and the renewal of industry exploration agreements with ASRC.

The state sponsored AGIA pipeline option has been approved by the state legislature. Under this approval, the state issued a license to TC Alaska (a subsidiary of TransCanada) which will provide state funding to TC Alaska to proceed with planning for a pipeline and to file an application with Federal Energy Regulatory Commission to build it (PN, 2008d). ConocoPhillips and BP Alaska are planning an alternate proposal for a gas pipeline and anticipate spending $600 million over the next three years to evaluate and plan for construction (PN, 2008f). Additionally, Enstar Natural Gas has had discussions with North Slope gas explorers (Anadarko and partners) regarding the possibility of a 690 mile small-diameter bullet-line from potential gas discoveries in the souther foothills of the Brooks Range to south-central Alaska (PN, 2008e).

2.3.4.1 Colville-Canning Province: State and Native Lands and State Waters of the Beaufort Sea

During the last decade of the 20th Century the first few years of the 21st the bulk of exploration and development has continued to take place within the Colville-Canning area and the adjacent shallow waters of the Beaufort Sea. However, the type of play and the players were undergoing significant change during this period. The major producers, ConocoPhillips, BP Alaska, and ExxonMobil played a reduced role in terms of areawide exploration and leasing. By 2003 BP Alaska had virtually ceased to participate in lease sales, was conducting exploration solely in and around the existing producing areas, and was concentrating on increasing production from existing fields. ExxonMobil had completely abandoned exploration drilling by 2000 and had ceased to participate in lease sales. Only ConocoPhillips continued to participate broadly in lease sales and wildcat exploration drilling, but at a reduced level.

Companies previously uninvolved in North Slope exploration and production have picked up the slack and have been the most active participants in the areawide lease sales both on and offshore. They have also been increasingly active drillers and have discovered a number of small to moderate sized oil accumulations in the **last five or six years.**

2.3.4.1.1 Leasing

Between January 1, 1990 and April 30, 2008, the state conducted a total of 36 lease sales on the North Slope and the adjacent state waters of the Beaufort Sea (Table 2.2). The level of leasing activity and the size of lease offerings has varied greatly over this period, from years with no lease sales to years with three areawide lease sales. The annual offering has ranged from a low of zero acres in 1994 to over 10,000,000 acres per year from 2001 to the present.

The state commenced offering areawide sales in 1998 with State Sale No. 87; and **since 2001 there have been, two to three areawide sales per year (Table 2.2).** These have been the North Slope areawide sale, the North Slope Foothills areawide sale, and the Beaufort Sea areawide sale. **The areawide sales have resulted in the leasing of an average of 481,154 acres leased per year or more than double the previous annual average of 226,098 acres per year for the period 1991 through 1997.** Prior to the establishment of the areawide sales, two to three localized sales were held per year with an average offering of approximately 1,000,000 **acres** per year.

Figure 2-5 shows the leases acquired and remaining after 1999 through February 2008. Figure 2-6 shows the exploration wells drilled from 2000 through April 2008.

The ASRC has continued to make its extensive landholdings, especially those in the foothills, available for exclusive exploration agreements. From the late 1990s to the present time, Anadarko Petroleum Corporation, and a varying group of partners, have had such an agreement with ASRC. The foothills land position is ideally situated to provide excellent opportunities for a major gas exploration effort. ASRC has also leased acreage through the competitive bidding process. Prior to the onset of the state of Alaska areawide lease sales in

1999, ASRC participated by offering selective tracts in State Sales No. 75 and 86a **(Table 2.2)**. From 1999 to the present, ASRC land has been offered with State lands in the areawide sales.

Many of the leases acquired at these and earlier lease sales have been relinquished back to the State by the winning bidder and only a fraction of the total acreage leased is still retained by the lessees **(Figure 2-3)**. One of the most significant relinquishments was by Burlington Resources. They relinquished 32 tracts with a total of approximately 185,000 acres that had been acquired in the North Slope Foothills 2001 sale.

The impacts of the areawide sales, the interest in gas as a commercially viable resource, and the emerging significance of NPRA are all reflected in **Figure 2-5**. **This is even more dramatically demonstrated when only the last eight or nine years are considered.** Within the Colville-Canning area, as recently as 2000, the bulk of the leasing was concentrated in the area south and southeast of Prudhoe Bay. In 2001 and 2002, much of the leasing activity shifted south to the foothills belt **(Figure 2-5)**, with some leasing by smaller companies in the shallow state waters of the Beaufort Sea. This transfer of interest was driven by the prospects of a gas pipeline and the well-recognized gas potential of the large structures of the Brooks Range foothills.

Once the majority of the obvious foothills features had been leased and the pipeline was not moving forward, leasing activity shifted back to the north and blocks south of the producing fields and offshore tracts dominated. Both of these areas provide the opportunity to pursue and develop smaller oil prospects that would be developed as satellites to the major producing fields and depend upon the existing infrastructure to be economically viable.

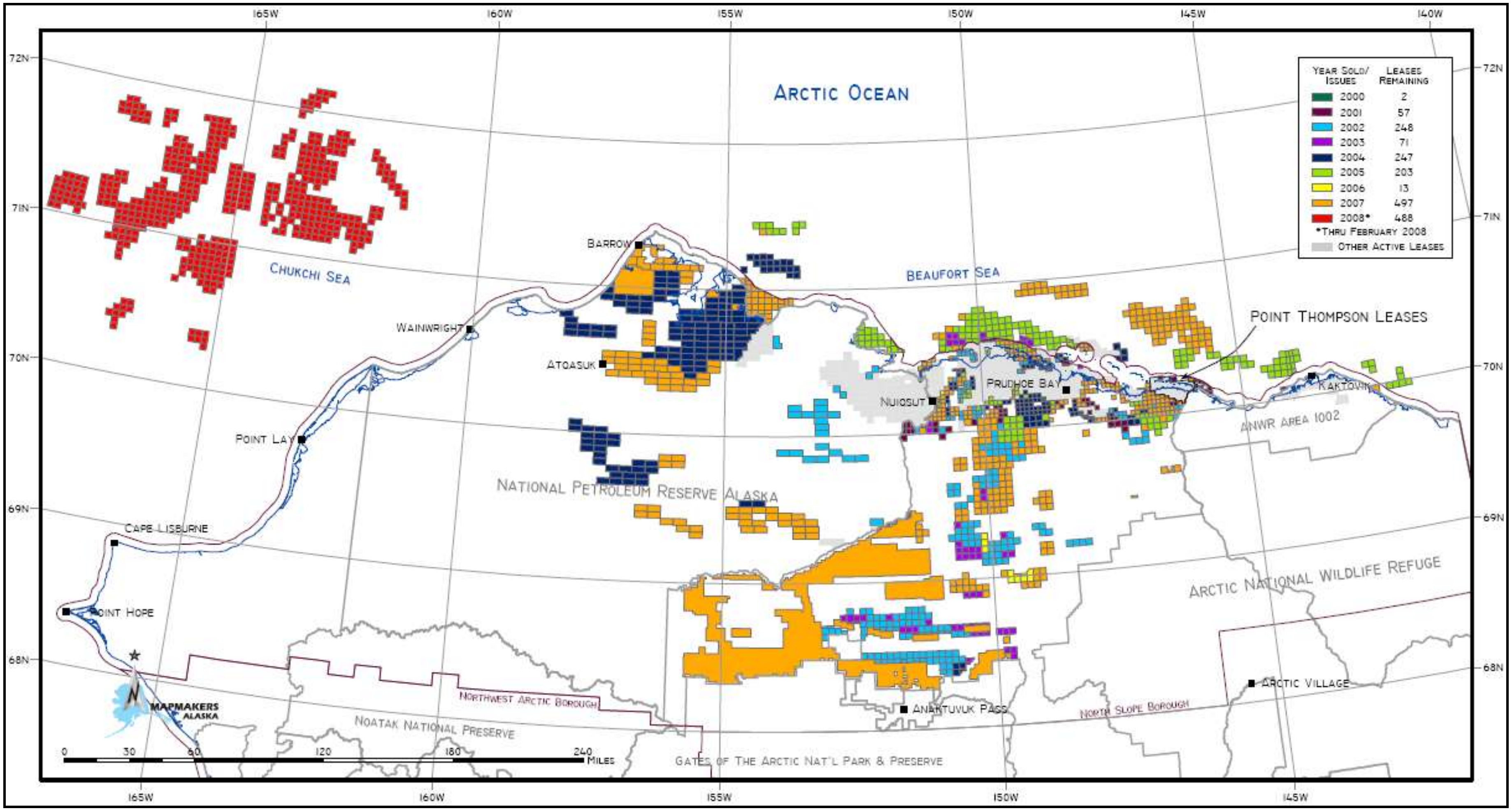

Figure 2-5. Lease acquisitions, 2000 through February 2008.

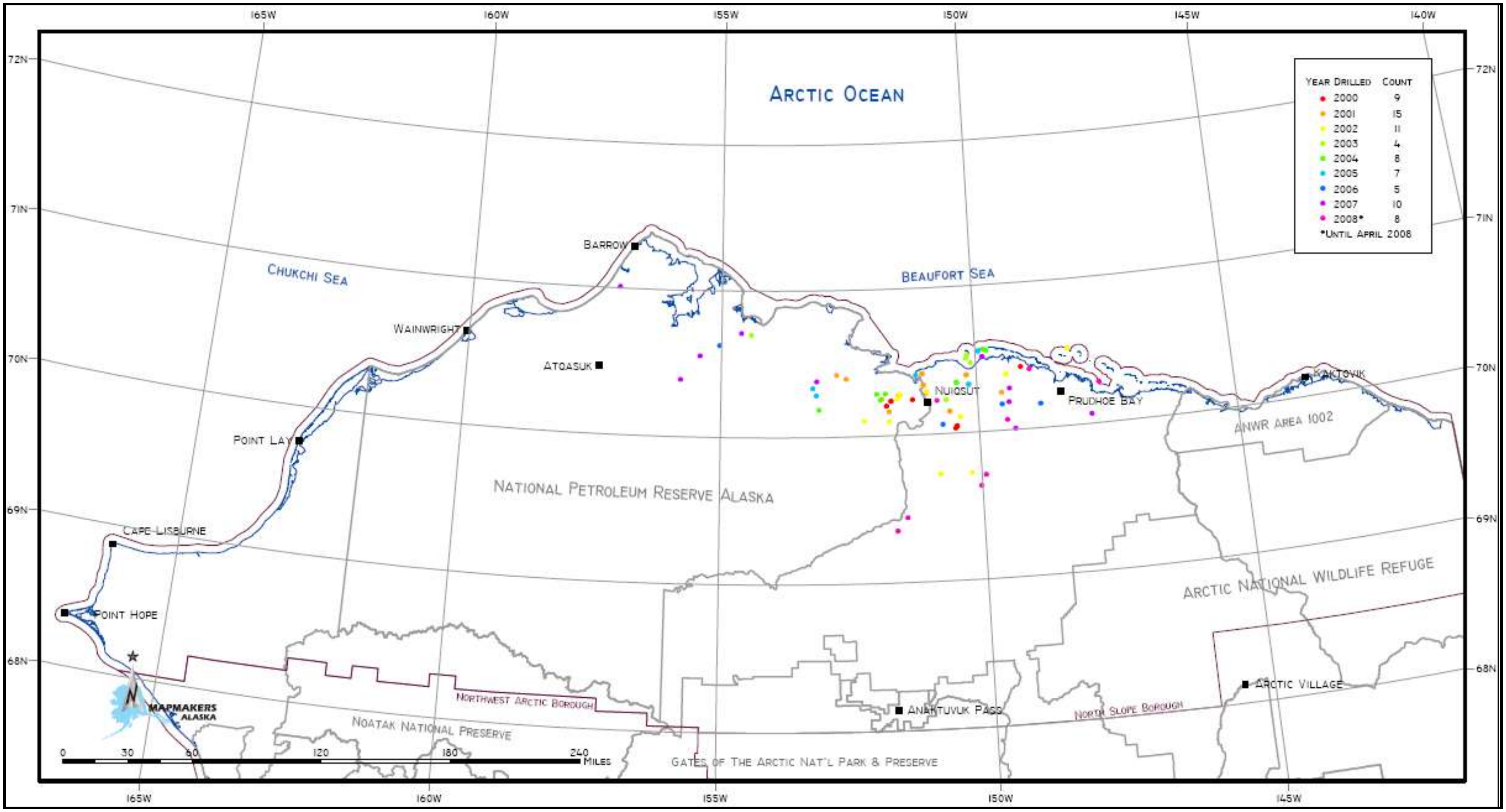

Figure 2-6. Exploration wells, 2000 through April 2008.

2.3.4.1.2 Data Acquisition

The trend of major companies to leave the North Slope or to decrease competition by mergers reached a zenith in the late 1990s and early 2000s. This has been only partially offset by the arrival of small to intermediate sized companies that have more limited budgets and thus acquire less seismic data and focus on small select areas. Additionally these smaller companies tend to not sponsor geological field programs.

There was very little in the way of industry-sponsored geological field work in the 1990s with an average of one to two geological field crews (1 to 1.5 crew-months) per year. **To this point in the 2000s, the activity level has increased modestly to two to four field crews (1.5 to 3 crew-months) per year.** There were more companies involved than the number of crews may suggest, since some of the field programs were jointly-sponsored by two or three companies.

The 2D seismic acquisition totals 7,593 line-miles (Table 2.3) with some portions of this acquired in NPRA and the shallow Beaufort Sea. Based on Kornbrath et al. (1997) at least 2,615 miles were acquired in NPRA between 1992 and 1997, with additional acquisition since that time. Thus, it is probable that only 3,000 to 4,000 line-miles of 2D seismic data were acquired within the Colville-Canning province.

Compared to prior years, the acquisition of 3D seismic data increased dramatically in the 1990s with a total acquisition of 10,736 miles between January 1, 1991, and December 31, 2007 (Table 2.8). Once again some percentage of these data were acquired in NPRA and the shallow Beaufort Sea. Kornbrath et al. (1997) reported a 3D program in 1996 that acquired 152 square miles and there have been numerous programs since that date. Several of the companies that leased large blocks in the foothills have acquired 3D seismic programs. A conservative estimate of Colville-Canning 3D acquisition during the period in question is **6,500** miles. There were four 3D programs in the state waters of the Beaufort Sea in the early 2000s, one marine and three hardwater **(Table 2.8)**. Anadarko has acquired both 2D and 3D seismic programs across prospective features underlying portions of the ASRC acreage for which they and their partners currently have exclusive exploration rights.

Costs of seismic acquisition and processing may constitute a significant portion of a company's exploration budget. **In 2004, the costs for acquisition of a 2D seismic program averaged about $15,000 per line-mile for onshore and hardwater surveys (Hastings, 2005). An estimate of current costs, including fuel at $3.00 per gallon, but not transportation of fuel, is $25,000 to $30,000 per line-mile (Watt, 2008). Based on 2004/2005 processing costs, the total costs would be increased by an additional $700 per line-mile.**

The most recent marine 2D seismic program was acquired by GX Technology Corporation in 2006. This program was shot in the Chukchi Sea and 1,915 line-miles of data were acquired. There are no numbers available regarding costs. In 2005, the estimated costs for a marine 2D program were about $15,000 to $20,000 per line-mile, if the seismic vessel was steaming at 4 knots/hour, 24 hours a day. It is probably safe to assume that those costs are now higher by about 10 to 20%.

As one would anticipate, costs for 3D acquisition and processing are higher. **In 2004, reconnaissance onshore and hardwater 3D programs averaged about $35,000 per square mile. In-field 3D programs were much more expensive and averaged about $60,000 per square mile. These estimates do not include fuel and transportation costs, which are paid by the client. The cost of a 3D program increases as spacing decreases (Hastings, 2005). Current costs, in this case including fuel, average about $30,000/ square mile near Prudhoe Bay, high density 3D for exploration averages about $40,000 per square mile, and super high density 3D for development averages $100,000 per square mile (Watt, 2008).**

The most recent marine 3D seismic programs were acquired in the Beaufort and Chukchi seas in 2006 and 2007. Personal communications indicate that the cost estimates supplied in 2005 are still valid and for acquisition and processing of a marine 3D survey the cost is approximately $120,000 per square mile.

These costs will probably continue to be representative for the foreseeable future, in the areas currently being explored and exploited. For more remote areas and the Chukchi Sea, the costs should be expected to be higher because of the distance from infrastructure and length of supply routes.

2.3.4.1.3 Exploration Drilling

Exploration drilling during the 1990s was widely dispersed and 84 exploration wells were drilled across the North Slope and in the Beaufort and Chukchi seas (Figure 2-2). There is some discrepancy in the numbers, based on how various agencies classify exploration wells. Approximately 70 of the 84 exploration wells were drilled within the Colville-Canning area/shallow Beaufort Sea area.

The majority of these wells were drilled along the Barrow arch trend both on and offshore in state waters. Much of this activity was concentrated in the vicinity of the Colville delta, where the Alpine discovery was made. These wells included the ARCO Nuiqsut No. 1, which is on ASRC lands. Only six exploration wells were drilled south of 70° north latitude. The ARCO Big Bend No. 1 drilled on ASRC acreage was one of these.

Drilling activity varied over the decade and two peaks of activity occurred during the 1992 to 1993 and 1996 to 1998 drilling seasons. In 1992 and 1993, a total of 22 exploration wells were drilled and in 1996 through 1998 when 26 wells were drilled.

The 2000 through 2008 exploration drilling resulted in a total of 77 exploration wells (Figure 2-2) with 50 of them being in the Colville-Canning area. Approximately 75% of these wells were drilled in the vicinity of the Colville delta and the adjacent area, just to the north and northwest of the Kuparuk field. The ConocoPhillips Lookout No. 2 was drilled on ASRC leases in the Colville Delta area.

Currently, exploration wells are often drilled far from the existing road network and require the construction of ice roads or the use of tundra-sensitive vehicles such as Rolligons. All exploration wells are drilled during the winter and most are accessed and supplied by ice roads. Several factors impact the cost and feasibility of ice road construction. Chief among these are, nature of the terrain including the number and length of river crossings, the availability of lakes for water/ice, and road maintenance. An ice road 6 inches thick and 30 to 35 feet wide would require 1 million to 1.5 million gallons of water per mile. **The cost of such an ice road, including fuel, camp support and other ancillary costs, may range from $200,000 to $250,000 per mile (Brassfield, 2008).**

Due to the lack of permanent roads and the costs and environmental consequences associated with building gravel drilling pads for exploration wells, the current practice is to build ice pads for exploration wells and simply allow them to melt away after the drilling season. In rare instances, these pads have been insulated and used for two seasons to drill an exceptionally deep well or for a multiwell program. A 6-acre drilling pad, 12 inches thick, would require approximately 2,000,000 to 3,600,000 gallons of water and cost $300,000 to $500,000 to construct. Recently, at least one operator has been experimenting with an elevated drilling platform constructed from portable lightweight modules. This approach may have application in areas where there is no access to an adequate water supply for ice pad construction. Offshore exploration drilling is accomplished by extended-reach horizontal drilling from onshore sites, from offshore barrier islands, from man-made ice- or gravel islands, or via ice-resistant drilling vessels.

2.3.4.1.4 Discoveries

In the Colville-Canning area and the state of Alaska waters of the Beaufort Sea, 13 discoveries were made in the 1990s and 8 in the 2000 through 2008 time frame (see Table 2.5 and Table 2.6 for their recovery dates). The discoveries are shown on Figure 2-4. Twelve of these 21 fields are either currently producing or will be in the near future (Table 2.5). The other nine (Figure 2-6) contain insufficient reserves to be developed, are too remote at this time, or have been discovered in the last year or two and are being evaluated for development. The discoveries are listed below in Table 2.11 with cumulative production through December 31, 2007.

Table 2.11. North Slope oil and gas discoveries between 1990 and 2008 (from Table 2.5 and Figure 2-6).

Oil/Gas Field	Cumulative Production (December 31, 2007)
Badami Field	**5.2 MMBO**
Tarn Field	**86 MMBO**
Kalubik Field	soon to be developed
Fiord Field	soon to be a satellite for Alpine (CD-3)
Cascade Field	????? MMBO[16]
Thetis Island Field	not developed
Alpine Field	**260 MMBO**
Raven Field	**1.62 MMBO**
Sourdough Field	not developed
Gwydyr Bay Field	soon to be developed[17]

[16] Now producing as a part of the Milne Point Kuparuk pool.

Midnight Sun Field	**16.6MMBO**
Sambucca Field	not developed
Eider Field	2.7 MMBO
Meltwater Field	**12.24 MMBO**
Palm Field	???? MMBO[18]
Nunaq Field	**6.93 MMBO**
Qannik Field	**0.055 MMBO**
Oooguruk Field	**Production began mid-2008**
Nikaitchuq Field	**Start-up in mid- to late-2009**
North Shore	**Not developed**
Tofkat	**Not developed**

The 10 producing fields have an estimated ultimate recovery of 975 MMBO. The Kalubik and Gwydyr Bay fields are clustered in the vicinity of the Oooguruk, Nikaitchuq, and other existing fields and will probably be developed within one to three years. The two most recent discoveries – North Shore and Tofkat (PN, 2007d) – will probably be developed in that time frame.

The Badami field was shut-in by BP Alaska due to production problems and reservoir continuity issues. BP is testing three techniques to redevelop the field and put it back on production at some later date**. It may never reach the potential ascribed to it.**

2.3.4.2 Beaufort Sea – Federal OCS

The Beaufort Sea OCS area has continued to see exploration activity but at reduced levels. The failure of the Mukluk well in 1983 and the inability of the discoveries that were made during the 1980s to yield economic quantities of oil significantly reduced the level of activity during the **1990 to 2008** time interval. Despite the poor results leasing, exploration drilling, and discoveries continue to occur in the Beaufort Sea OCS.

2.3.4.2.1 Leasing

The MMS held six OCS lease sales in the Beaufort Sea from 1991 through 2007 (Table 2.2**). In these six sales, a total of 54,256,114 acres were offered and the sale size ranged from 18,556,976 (No. 124) to 920,983 (No. 170) acres.** Sale No. 124 was an areawide sale and subsequent offerings have consisted of only portions of the total available area. **These sales resulted in 1,742,987 acres being leased.** The only active OCS leases are leases acquired in the sales held during the 1990s and 2000s **(Figure 2-3)**. **The 2000 through February 2008** leasing activity is presented by year in **Figure 2-5. The two most recent sales (No. 195 and No. 202) resulted in leasing more than 1,000,000 acres, including the old Hammerhead (now Sivullig) structure, the arrival of ENI Petroleum US LLC, and Repsol E&P USA, Inc. to the Alaska OCS, and the return of Shell.**

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[17] May be the focal point for the development of several small accumulations in the general area (PN, 2004b).
[18] Now producing as part of the Kuparuk field.

2.3.4.2.2 Data Acquisition

Acquisition of seismic data included both 2D and 3D acquisition technology. A total of 5,316 line-miles of 2D data were acquired between 1991 and 1997 **(Table 2.3)**. No 2D seismic data have been acquired in the Beaufort OCS since 1997. The acquisition of 3D seismic data in the Beaufort Sea OCS totals 12 programs during the 1990s and early 2000s **(Table 2.8**). These programs were equally divided between hardwater and marine acquisitions.

2.3.4.2.3 Exploration Drilling

Drilling activity in the Beaufort OCS was significantly reduced relative to the levels seen in the 1980s. Eleven exploration wells were drilled in the Beaufort OCS region between January 1990 and December 2004 (Figure 2-2). The McCovey No. 1 well is the only well drilled in the OCS since the beginning of the 21st Century **(Figure 2-6)** and is in fact the only well drilled in the Beaufort OCS since 1997. This low level of activity is largely driven by three factors: (1) failure to find large accumulations (1.0 + BBO), (2) environmental concerns, and (3) high cost of drilling in water depths greater than 40 to 50 feet.

Exploration drilling in the Beaufort OCS was expected to remain at low levels until at least 2010, when declining production in existing fields will put increased pressure on industry to find new sources of production. However, the recent acquisition of leases on the Hammerhead, Wild Weasel, and other structures by Shell during OCS Sale 195 (Table 2.2), Shell's acquisition of two rigs to drill in the Beaufort Sea and their subsequent announced intend to drill, mean that drilling activity will increase when and if the issues are resolved.

2.3.4.2.4 Discoveries

Two of the 10 exploration wells encountered hydrocarbons **(Table 2.6)**, the Kuvlum No. 1, drilled in 110 ft of water, offshore from the western end of the 1002 area **(**Figure 2-6**)**, and the Liberty No. 1, drilled in 21 ft of water, on the previously discovered Tern accumulation **(**Figure 2-6**). In the 2005 Beaufort Sea Sale 195, Shell placed bids on the tracts containing the Kuvlum discovery, but the MMS rejected the bids, considering them to be inadequate and not representative of the value of the tracts.**

The Kuvlum structure is currently unleased but it is estimated to have recoverable reserves of approximately 400 MMBO. Because of its remote location and water depth it has not been developed. Development of the Point Thomson field may positively impact the future of the Kuvlum accumulation as well as that of Sivulliq. The Liberty field, with about 150 MMBO, is in much shallower water and is less than 8 miles from the Endicott facilities. BP Exploration (Alaska) has sanctioned the development of Liberty and plans to delineate and develop the field from the Endicott production island (PN, 2008c). The first well will be a 40,000 ft extended-reach horizontal well, and the rig is under contract. BP expects first production from the Liberty field in 2011. Wells are expected to be capable of delivering 15,000 BOPD or more (PN, 2008c).

2.3.4.3 Chukchi Sea – Federal OCS

The activity in the Chukchi Sea OCS consists of two phases. The effort in the 1990s was primarily a continuation of the leasing and follow-up exploration of the late 1980s.

That phase of activity was confined to 1990 and 1991. The second phase commenced in early 2008 with the highly successful OCS Lease Sale No. 193 (Table 2.2). This sale is expected to initiate a large-scale exploration effort.

2.3.4.3.1 Leasing

There have been two lease sales in the Chukchi Sea during the 1990 to 2008 time period. The first sale was OCS Sale No. 126, which was held in 1991. A total of 18,987,976 acres were offered and 159,213 acres were leased. The second sale was held in February 2008, with an offering of 5,354 blocks totaling 29,389,287 acres. The sale drew high bids of more than $2.66 billion for 488 tracts totaling 2,758,408 acres (Table 2.2) (MMS, 2008b). Shell and ConocoPhillips were the most aggressive bidders, with Shell exposing $2.2 billion and having a total of $2.118 billion in apparent high bids (MMS, 2008c).

Three major international companies made their presence known by participating in the sale and apparently acquiring acreage positions in the basin. These companies are StatoilHydro USA E&P, Inc., Repsol, and ENI. This further indicates that the area is looked upon as having great potential despite its remote location.

2.3.4.3.2 Data Acquisition

Much of the seismic acquisition was completed by the end of 1991. A total of 861 line-miles of 2D seismic data were acquired during the 1990 and 1991 seasons **(Table 2.3)**. **An additional 1,915 line-miles were acquired in 2006 (Table 2.3) and that is the most recent 2D survey. There were no 3D seismic programs acquired until 2006. During 2006 and 2007 three 3D surveys were acquired in preparation for OCS Lease Sale 193. These totaled approximately 2,550 square miles (Table 2.8).**

2.3.4.3.3 Exploration Drilling

Four exploration wells were drilled in 1990 and 1991, in water depths ranging from 137 to 152 ft **(Figure 2-2)**. These were the Burger No. 1, Popcorn No.1, and Crackerjack No.1 wells all drilled by Shell and the Diamond No.1 well drilled by Chevron. There are good to excellent oil and gas shows in all three of the Shell wells (Sherwood et al., 1998b). The Burger well has two zones of gas pay, in a 110-foot thick Kuparuk-C sandstone equivalent and a 36-foot thick deltaic Nanushuk sandstone. The Popcorn well has gas and condensate in a 20-foot thick Kuparuk (?) equivalent sandstone atop the Jurassic unconformity, oil shows in Torok turbidites, and Permian and Pennsylvanian carbonates of the Lisburne Group. The Crackerjack well has oil shows in Early Cretaceous turbidites of the Torok and in sandstones of the Nanushuk Formation. A zone of gas pay was identified in the Echooka Formation. The Diamond well has trace oil shows in sandstones of the Torok Formation, Ivishak Formation, Echooka Formation, and the carbonates of the Lisburne Group (Sherwood et al., 1998b).

2.3.4.3.4 Discoveries

At least one discovery can be attributed to this brief round of drilling. The Burger No. 1 well is a gas discovery **(Table 2.6)**, “possibly with multi-TCF reserves” (Sherwood et al., 1998b). The primary gas zone is the Kuparuk-C equivalent. Preliminary estimates placed the range of estimated recoverable gas resources at 2 to 10 TCF with a mean of 5.0 TCF. Recent reevaluation of the Burger gas discovery has estimated the mean gas resources for the most likely case at 14.0 TCF and condensate at 724 MMB (Craig and Sherwood, 2005). Craig and Sherwood (2005) state that: "Burger could represent the largest hydrocarbon discovery to-date on the Alaska OCS. However, volumetric estimates for the Burger pool are highly speculative because only one well was drilled on a very large structure."

2.3.4.4 National Petroleum Reserve-Alaska (NPRA)

Exploration interest and activity were renewed following the discovery of the Alpine field, just to the east of the NPRA in 1994. This discovery and the additional exploration drilling it spawned led to the decision to reopen NPRA to leasing and exploration. Thus the federal government, through the BLM, began to lease acreage in 1999. These sales led in turn to exploration drilling and to several small discoveries.

2.3.4.4.1 Leasing

The BLM has held **four** lease sales within NPRA since the renewal of leasing in 1999 **(Table 2.2)**. Two sales were held in the northeastern planning area, in 1999 (Sale No. 991) and 2002 (Sale No. 2002). The acreage offered in Sale No. 991 was 3,900,000 acres and approximately 22% or 864,204 acres were leased. Sale No. 2002 offered 3,051,500 acres, essentially the acreage not leased in the 1999 sale. An additional 579,269 acres were leased in the 2002 sale. **A third sale was scheduled to coincide with the 2006 northwestern planning area sale; however, because of environmental concerns this portion of the sale was cancelled. Two sales were also held in the northwestern planning area. The first sale (Sale No. 2004) presented a total of 5,800,000 acres and 1,403,561 acres were leased (Table 2.2). A second sale in the northwestern planning area offered 5,451,766 acres and yielded high bids on 81 tracts for a total of 939,867 acres (Table 2.2).**

Issues concerning the environmentally sensitive area of Teshikpuk Lake may cloud the leasing picture in that and some other areas considered to be critical wildlife habitat. As a consequence of the relative success of past sales the BLM is planning to conduct periodic sales in NPRA and with continued interest these should be held every two to three years for the foreseeable future.

2.3.4.4.2 Data Acquisition

Data acquisition has been largely limited to 2D and 3D seismic programs. A modest amount of geological field work was done and continues to be planned. The geological programs focus on the Cretaceous exposures in southern NPRA and to the south of NPRA. Geological field work has averaged about three to four crew weeks per year for the last decade.

Seismic program information, as supplied by the ADOG and the MMS, does not distinguish between data acquired within NPRA and on state of Alaska lands. The best estimate available is that approximately 3,000 to 3,500 line-miles of 2D data have been acquired within NPRA **(Table 2.3)**. This represents the 2,617 line-miles reported by Kornbrath et al. (1997) plus post-1997 acquisitions of 500 to 1000 miles. **Some of the seismic acquisition shown on Table 2.3 and attributed to the Colville-Canning area apparently was acquired in NPRA.**

The magnitude of 3D seismic acquisition is not known with certainty but is probably on the order of 3,000 to 3,500 square miles **(Table 2.8)**. This may be on the optimistic end of the spectrum, but the use of 3D for both exploration and development in the pursuit of stratigraphic traps has increased in recent years and this range of acquisition seems in line with those activities.

2.3.4.4.3 Exploration Drilling

The first well to be drilled following the 1999 lease sale was the ConocoPhillips Spark No. 1. It was completed as a dry hole in April 2000. **Since then, an additional 25 exploration wells have been drilled within NPRA (Figure 2-2). More specifically, 21 exploration wells have been drilled within the northeastern planning area (Figure 2-4), and five exploration wells were drilled in the northwestern planning area. The most westerly well is the ConocoPhillips Intrepid No. 2, located in Township 19 north and Range 20 west, approximately 7 miles northeast of the ARCO Brontosaurus No. 1, which was drilled in 1985 (Figure 2-2).**

The annual exploration drilling activity for the **2000 through 2008** is summarized in **Figure 2-6.** The bulk of the exploration within NPRA has been focused **to the west and** southwest of Alpine **(Figure 2-4 and Figure 2-6**). **Fourteen of the 26 wells drilled to date are in this area.**

2.3.4.4.4 Discoveries

The NPRA exploration is on the verge of yielding production. To date at least three discoveries have been made in the area to the southwest of Alpine. These are the Spark, Lookout, and Alpine West fields. They will all be developed as satellites to the Alpine field. Estimated EUR is about 50.0 MMBO per field **(Table 2.5)**. DST results from four wells have been released (BLM, 2005b). These wells are the Lookout No. 2, Rendezvous No. 1, Spark 1A, and Carbon No. 1 **(Figure 2-4)**. The test results give rates of 320 to 4000 BOPD of high gravity oil and 5.0 to 26.0 MCFGPD.

The drilling activity in the northwestern planning area has yielded mixed results. FEX drilled a total of four exploration wells during the 2006 and 2007 winter drilling seasons. All four encountered oil, but at least in part because of the remoteness of the locations, they were deemed subcommercial (PN, 2007e). However, two wells were suspended rather than plugged and abandoned. FEX officials stated that for the two suspended wells the "initial estimate of contingent resources present" was "300 to 400 million barrels" net to FEX, which has a 60 to 80% working interest in the leases (PN, 2007e). The nearest well is more than 150 miles west of Prudhoe Bay and TAPS. This requires a discovery or series of discoveries of large size to make any development opportunity attractive.

Results from a number of wells remain confidential, the most intriguing of which is the Puviaq No. 1. Due to its location in the extreme northwest corner of the northeastern planning area, it is a potential key to the prospectivity of the Teshekpuk Lake area and the northern portion of the northwestern planning area.

2.3.4.5 1002 Area of the Arctic National Wildlife Refuge (ANWR)

There was no exploration or development activity within the 1002 Area during the 1990s and early part of the 2000s. The area remains off-limits to the petroleum industry despite repeated efforts in congress to approve exploration and development of this portion of the Refuge. The USGS reevaluated the 1002 Area's hydrocarbon potential (Bird and Houseknecht, 1998) and concluded that the mean technically recoverable reserves within the 1002 Area are 7,668 MMBO and within the entire study area (1002 Area, native lands, and adjacent state waters within the 3-mile limit) 10,322 MMBO. These numbers are appreciably higher than the earlier USGS estimates and provide further incentive for exploration.

2.3.5 Summation of Activities to December 31, 2007

With varying degrees of intensity and success the North Slope and adjacent OCS areas of the Beaufort and Chukchi Seas have been the foci of oil exploration since the mid-1940s. The emphasis is correctly placed on "oil exploration" since there has not been and still is no market for gas, **but the efforts to build the gas pipeline have resulted in the first fledgling gas exploration programs. To date all gas discoveries have been incidental to the search for oil**.

The two phases of federally sponsored exploration, of what is now NPRA, found several small subeconomic accumulations of oil and gas and provided a wealth of geological, geophysical, and well data as the basis for future evaluation of the hydrocarbon resources of the North Slope and adjacent OCS areas. The first phase, in the 1940s and 1950s, focused on the Upper Mesozoic, primarily the Cretaceous section. This drilling program discovered several small gas fields, and a number of these now provide gas to the village of Barrow. The second exploration phase in the late 1970s and early 1980s was directed toward the evaluation of the Prudhoe Bay area plays, largely centered along the Barrow arch. These efforts proved to be unsuccessful.

Commencing in 1958, the area to the east of NPRA and west of the Canning River was made available to the petroleum industry for exploration. After nearly 10 years of seismic acquisition, geological field work, and 11 dry holes, the first major discovery was made at Prudhoe Bay**. This discovery was the stimulus for a major reallocation of industry resources to the North Slope and resulted in leasing and exploration programs that have led to the discovery of additional major oil fields, with attendant smaller satellite fields and a combined EUR of more than 22.0 BBO. As of January 1, 2008, nearly 15.7 BBO have been produced or about 70% of the EUR (Table 2.5).** Known gas reserves, largely associated with these oil discoveries, total 35 TCF.

The exploration success of the Colville-Canning area led to leasing and industry-sponsored exploration in the Beaufort and Chukchi Seas and within NPRA. The exploration success is the result of widespread and predictable leasing programs, extensive geological and geophysical data acquisition programs, and exploration drilling programs with diverse objectives. **Through the first quarter of 2008, there have been a total of 82 lease sales (Table 2.2) since the onset of leasing in 1958, and more than 31.5 million acres have been leased. Some acreage has been leased more than once.**

As of March 1, 2008, there were a combined total of 2,364 active leases in the Chukchi Sea, Beaufort Sea, NPRA, and the Colville-Canning area with the majority of the leases (1,826 or 77%) issued in the last nine years. These newer leases are concentrated in NPRA, the Beaufort Sea OCS, the Chukchi Sea OCS and in the Brooks Range foothills (Figure 2-3). The 2000 to February 2008 leasing activity is shown on (Figure 2-5). It emphasizes: (1) activity by independents and smaller companies in the Colville Delta-Gwydyr Bay area, (2) expectations for a gas pipeline and market with the foothills acreage, (3) westward extension of exploration into NPRA based on the discovery at Alpine, (**4) renewed interest in the OCS areas, specially the Chukchi Sea, and (5)** continued emphasis by the major producers on close-in satellite development.

More than 231,000 line-miles of 2D seismic data had been acquired by the end of 2007, with approximately 61,000 miles of land and hard water data and more than 170,000 miles of marine data (Table 2.3). The land 3D seismic acquisitions total more the 11,400 square miles. The amount of OCS 3D is not available but at least 20 programs have been completed, with 11 hard water and 9 marine acquisitions (Table 2.8).

Exploration drilling has been widespread but not intensive. **The definition of an exploration well, as used by the state, is very inclusive and for the purpose of this report an attempt was made to restrict the definition to wells drilled to discover or confirm not delineate new oil accumulations. Using this more restrictive definition,** for the North Slope and in the adjacent Beaufort and Chukchi Seas, a total of **484** wells have been classified as exploration wells **(Figure 2-2)**. When the size of the area is considered, this is a very low exploration drilling density. **The Colville-Canning area and the adjacent state waters of the Beaufort Sea are the most extensively and intensively explored areas with approximately 323 exploration wells. The total for state and native lands is approximately 23,000 square miles (Bird et al., 2005) and yields a well density of one well per 71 square miles. Within NPRA a total of 126 "exploration" wells have been drilled. Of this number 45 were core tests. If the core tests are discounted, the federal exploration efforts and industry exploration drilling has totaled 81 exploration wells. With an area of approximately 36,000 square miles this yields a drilling density of one well per 445 square miles.** The Beaufort Sea OCS shelf has an area of approximately 19,000 square miles with 30 exploration wells. The exploration well density is one well per 630 square miles. The Chukchi Sea planning area covers 64,500 square miles (Thurston and Theiss, 1987) with only five exploration wells, for a drilling density of one well per 12,900 square miles.

From an exploration perspective, the North Slope and adjacent areas are far from resembling a mature petroleum province. **The majority of the wells in both the state onshore and near-shore Beaufort Sea are clustered along the Barrow arch trend with only 47 of the 323 exploration wells located south of 70º north latitude Figure 2-2).** The area south of 70 north latitude constitutes nearly 75% of the state acreage. **This southern portion of the state land holdings has a well density of one well per 367 square miles.** Thus only the area along the Colville-Canning portion of the Barrow arch and the adjacent portion of the Beaufort Sea has experienced moderate to high exploration drilling activity. **Here, the drilling density is approximately one exploration well per 21 square miles.**

Figure 2-6 shows the most recent exploration drilling and includes wells drilled between January 1, 2000, and the end of the 2008, drilling season. The areas of concentration continue to be in or near currently established production and infrastructure and westward into NPRA. The latter activity is a continuation of the evaluation of the productive trend at Alpine and its satellites and the search for Brookian turbidite and additional Kuparuk production. The newest exploration activity includes exploration for gas in the Brooks Range foothills, at Gubik and south of Gubik at Chandler (Figure 2-6)

Large volumes of gas have been discovered in the exploration process and vast tracts of acreage with high gas potential remain under- or un-explored. With the currently published estimates of gas at Point Thomson, Prudhoe Bay and adjacent fields, and the recently revised volumes for Burger, the known resource base is approximately 50 TCF. This resource and other potential gas resources await a decision to build a gas pipeline (PN, 2008n).

The role of gas in the future of the ANS exploration and development is described in Section 2.4 through Section 2.4.2 Long Term (**2018/2020 to 2050**).

2.4 Future Exploration Potential and Activity

"Even if prices and political stability were to continue to favor exploration and extraction of North Slope oil and gas, many variables bear on the amount of activity and the success of future exploration and development: land availability, the regulatory environment, pricing, technology, exploration concepts, competition, and the infrastructure" (National Research Council, 2003). The magnitude and success of future exploration and development will be largely dependent on the degree to which the following assumptions are satisfied:

A. Oil (and gas) prices remain high enough to support continued exploration and development.
B. Climate change will not be so great, during the next 50 years, to render current exploration methods obsolete or foreclose modifications, such as the use of Rolligons and new drilling platforms.
C. All new exploration and development activities will use technologies at least as good as those at Alpine.
D. Onshore exploration (and probable extraction) will continue to expand both southward into the foothills of the Brooks Range and westward across the NPRA.
E. Offshore exploration (and probable extraction) will continue, but at a cautious pace, along the Beaufort Sea coast/shelf from Point Barrow to Flaxman Island and possibly eastward to the Canadian border. The exploitation of the Chukchi Sea OCS will depend on anticipated success in adjacent portions of NPRA and the construction of a gas pipeline. **Recent lease sale results from the 2008 Chukchi Sea sale, suggest this may be an overly conservative position.**
F. Facility sharing agreements will be in place, which permit reasonable and affordable access for those companies not currently producing and transporting hydrocarbons.

G. A gas pipeline will be built and, over time, gas will become a significant if not the dominant component of many exploration and development programs and new explorers will have access to the gas pipeline.

H. The number of exploration companies, especially those with gas interests, will expand, competition will increase, and a greater variety of play types **and exploration provinces** will be evaluated and drilled.

Beyond the issues presented above, the fundamental control on oil and gas occurrence and distribution is the petroleum geology of the North Slope and variations in character of the source and reservoir intervals or their absence within and across the prospective areas. In the petroleum geology section, the distribution and character of these units were presented **and** provide a basis for the findings of this portion of the addendum report.

Exploration and evaluation of the hydrocarbon potential of much of the North Slope and adjacent offshore areas is still in its infancy. Despite the success in the Prudhoe Bay area, little exploration drilling has occurred across much of the region, and stratigraphic exploration has only recently become a meaningful component of most exploration programs. As discussed in the previous section, exploration drilling has been heavily concentrated along the Barrow arch trend, and most of that activity has been restricted to the Colville-Canning area. Oil has been and currently is the exploration objective of **virtually** all ongoing exploration programs. **It will continue to be the primary focus of near term exploration programs until such time as a gas pipeline has been approved, gas has been committed to the pipeline, and facility sharing and facility/pipeline access issues have been addressed and resolved.**

The basic assumptions for this projection of future activity are that there will be significant new discoveries and development of both oil and gas and a continued gradual decline in production from older fields. This decline of production from the older fields will likely influence the rate and timing of satellite development.

The future projections discuss activity in three major operating provinces based on administrative agency and physical environment. These are the state lands both onshore and offshore, the OCS areas of the Beaufort and Chukchi Seas, and NPRA. For completeness, a fourth province, the 1002 Area of ANWR, is included in the forecast. Much like the treatment in the prior sections these areas generally have similar restrictions, lease terms, and other regulatory aspects in common and thus have some degree of predictability regarding operational style and infrastructure.

In the original 2007 report, it was assumed that a gas pipeline would be approved within 6 to 12 months and gas production and shipping would commence in approximately 10 years, or about 2015 to 2016. The passage of nearly three years since these words were written has shown this to be an optimistic assumption. The timeline appears to have been set back at least two to three years. The gas pipeline will have a significant impact on exploration for and development of Arctic Alaska's petroleum resources. Thus, the future of exploration and development on the North Slope and adjacent areas is addressed as

having two components: (1) an oil-dominated near term, pre-major gas sales phase, building on current exploration trends and philosophies; and (2) an increasingly gas-dominated long term, post-major gas sales phase, relying on the development of a gas pipeline and open access to it and associated infrastructure. This transition is now estimated to occur in the 2018 to 2020 timeframe.

Publicly available federal resource estimates and other citations are utilized to frame or represent the magnitude of oil and gas that may be available or potentially discovered through comprehensive exploration programs. These numbers are not to be considered as absolutes but can be thought of as approximations of the order of magnitude of generated, migrated, and accumulated oil and gas.

Over time the estimates of undiscovered resources have been reported in a variety of formats. These include OOIP/OGIP, technically recoverable resources or reserves, and economically recoverable resources or reserves. The OOIP/OGIP is the estimate of the total volume of oil or gas in a reservoir or reservoirs prior to the onset of production. It does not represent the quantity of the resource that may be produced from the field. The OOIP at Prudhoe Bay was approximately **25** BBO. Technically recoverable resources (reserves) are the volume of oil and/or gas that may be technically and physically recovered independent of price. Economically recoverable resources (reserves) are that portion of the technically recoverable resources that may be economically recovered and are sensitive to both price and technology. **The current estimate of economically recoverable reserves at Prudhoe Bay is 14.654 BBO or approximately 59% of the OOIP and more than 46% greater than the original EUR estimate of 9.6 BBO (Table 2.5). This may be considered to represent reserves growth totaling 4.466 BBO for the Prudhoe Bay field.**

Table 2.12 is presented to provide a comparison of oil production and EUR for the ANS. The OCS areas are treated separately and have been excluded from this table.

Table 2.12. Comparison of ANS oil production, reserves, identified resources and estimated resources at three points in time: December 31, 1989 (Thomas et al.,1991); December 31, 2000 (EIA, 2001); and June 30, 2005 (Bird et al., 2005 and AOGCC, 2005).

Date of Source Report	Area	Oil Produced at Time of Report	Remaining Discovered Oil		Undiscovered Oil Resources	Total
			Producing Fields	Identified Developing Fields		
12/31/89	North Slope	7.36 BBO	6.33 BB0	1.96 BBO	12.43 BBO	28.08 BBO
	Colv.-Cann. and State Beaufort Sea				7.10BBO	
	NPRA				2.10 BBO	
	1002 Area				3.23 BBO	
12/31/00	North Slope	13.31 BBO	4.53 BBO	1.31 BBO	13.32 BBO	32.47 BBO

Date of Source Report	Area	Oil Produced at Time of Report	Remaining Discovered Oil		Undiscovered Oil Resources	Total
			Producing Fields	Identified Developing Fields		
	Colv.-Cann.				1.541 BBO	
	NPRA				1.480 BB0	
	1002 Area				10.3 BBO	
06/30/05	North Slope	14.30 BBO	4.93 BBO	1.83 BBO	25.0 BBO	46.06 BBO
	Colv.-Cann.				4.0 BBO	
	NPRA Entire Area				10.40 BBO	
	1002 Area Entire Area				10.60 BBO	

The data in Tables 2.7 through 2.14 are variously presented as unrisked undiscovered original oil/gas in place, unrisked undiscovered technically recoverable oil/gas, risked undiscovered technically recoverable oil/gas, risked undiscovered economically recoverable oil/gas, conditional undiscovered technically recoverable oil/gas, and conditional undiscovered economically recoverable oil/gas. Occasionally where only a single well has encountered an accumulation estimates are considered conditional (risked or unrisked) discovered oil/gas (Craig and Sherwood, 2005). In the discussion, clear distinctions are made among oil/gas-in-place, technically recoverable resources, and economically recoverable reserves. Where estimates of oil and gas volumes have been calculated in more than one format the various formats will be presented to permit the greatest possible opportunity to compare between or among areas treated differently by the assessment teams or agencies.

The determination of "economically" recoverable reserves is to a great extent a function of the assumed oil or gas price used by the assessors. As recently as 2002 (Bird and Houseknecht, 2002) the oil price range used to provide an estimate of economically recoverable reserves was approximately $22.00 to $30.00 per barrel. **The Energy Information Agency (EIA) (2008) states that the average West Texas Intermediate (WTI) price was $72.32 per barrel in 2007. Alaska North Slope crude is valued at $2.00 to $3.00 per barrel less than WTI. The real world price during late 2007 through the first half of 2008 was in the $100.00 to $135.00 per barrel range, peaking briefly at nearly $150.00 per barrel in mid 2008**. Oil prices dropped sharply into the $40.00 per barrel range during the last half of 2008 and have remained in that range during late 2008 and early 2009. It is probably reasonable to assume that a price above $30.00 per barrel will hold for the foreseeable future. This leads to the conclusion that most estimates of economically recoverable volumes of oil and gas using $40.00 plus per barrel are reasonable and in certain areas the economically recoverable volumes may approach the technically recoverable values. **Estimates of remaining technically recoverable resources, technical remaining reserves (TRR), are described in Section 3. Engineering Evaluations.**

One of the primary objectives of this segment of the report is to present a possible scenario for future exploration activity and discovery of economic quantities of hydrocarbons. The timing of these activities is an important aspect of this approach and the attempts to forecast when or where these may occur are fraught with uncertainty and must be recognized for what they are – **one perception of the best estimates of future events**. The information derived from published assessments of resources and the recent trends in leasing, exploration drilling, and discoveries are used to develop these forecasts.

In the near term **(approximately 2008 to 2018/2020)**, it has been assumed that in the individual areas of interest, drilling activity will continue at a pace at least equivalent to that of the last decade. Discovery frequency and size will similarly be of the same order of magnitude as the recent or known discoveries in the area. These assumptions may be conservative in the respect that they do not account for the discovery of fields in the upper range of resources ascribed to the various play types.

For the long term **(2018/2020 to 2050)**, the basic assumption is that by 2040 at least 50% and possibly 75% of the assessment volumes of technically recoverable oil and gas will have been discovered and economically developed. A recent evaluation of the sensitivity of oil price to volumes of economically recoverable oil indicates that at prices of $51.00/barrel (slightly above the current range of oil prices), more than 90% of the estimated technically recoverable resources of the 1002 Area are economically recoverable (Attanasi, 2005). This tends to suggest that the 50 to 75% guidelines used here are quite conservative in the current pricing environment.

Beyond 2040, the picture becomes so obscure that any attempt to put timing and location constraints on activities is probably meaningless. The timing and location of development are considered to be a function of proximity to the existing infrastructure, specifically TAPS and a future gas pipeline, which is assumed to be built along basically the same corridor as the oil pipeline, at least while traversing the North Slope and Brooks Range. Secondary and satellite fields require the development of infrastructure associated with large stand-alone fields like Prudhoe Bay, Kuparuk, and Alpine to minimize the cost of development.

Additional elements that may facilitate exploration and development are year-round gravel roads proposed by the state of Alaska. The proposal consists of four roads: (1) to NPRA from the end of the existing spine road, (2) a road to Point Thomson, and (3) and (4) roads east and west from the Dalton Highway into the foothills (PN, 2004d). The road to NPRA would be 20 miles long and a 3,300 ft bridge would span the Colville River, providing access to NPRA development areas and Nuiqsut. **At this time (2008) the future of this and the other roads seems uncertain.**

The coastal road to Point Thomson would be 55 miles long and built on state lands. This road will provide access to potential exploration and development sites within the northern portion of the Colville-Canning area and to the 1002 Area of ANWR if it is opened to exploration.

The foothills roads are intended to provide all-season access to oil and gas leases on state land in the Brooks Range. The western road is planned to extend to the upper Kuparuk River. This would greatly simplify the transportation issues since ice roads are often impractical because of slope and terrain breaks. The eastern road would provide the same function for access to leases east of the Dalton Highway. Both of these road proposals are awaiting a gas pipeline project approval.

2.4.1 Near Term (2008 to 2018/2020) – Pre-Major Gas Sales

The most immediate of the near-term exploration and development trends are demonstrated by **the recent exploration drilling shown on Figure 2-6**, **and are reinforced by the current lease status as reflected by the leasing and retention of leases for the last eight to nine years (Figure 2-5). These comprise the exploration activity of eastern NPRA, where the Alpine- and Tarn-like play trends are primary targets (the Kokoda and Iapetus wells of Figure 2-6) with the Kuparuk as a secondary objective; the exploration drilling east of the Colville Delta to Gwydyr Bay (the Tuvaaq and Ataruq wells of Figure 2-6) where reservoirs equivalent to those at Alpine and the Kuparuk/Milne Point fields are targets; drilling in the northwestern planning area of NPRA (the Intrepid No. 2, and the Aklaq No. 6 wells**); and the satellite exploration in and around Prudhoe Bay and the Kuparuk fields by the major operators. **The most recent activity has seen drilling in the Jacob's Ladder prospect targeting the Lisburne east of Prudhoe Bay, the Smilodon and Mastodon wells 35 to 40 miles south of the Kuparuk field with presumed Upper Cretaceous objectives, and the drilling at the Gubik and Chandler prospects east and southeast of Umiat for gas in Late Cretaceous units (Figure 2-6).**

The recent leasing activity, as shown by the active leases of Figure 2-5, support these exploration trends or philosophies and in addition highlight the gas-driven exploration interest in the Chukchi Sea, resulting from a range of 9.5 to 14.0 TCF believed to be associated with the Burger well (Craig and Sherwood, 2005). Exploration drilling in the Chukchi Sea area is years into the future and probably will be targeted toward a mix of oil and gas plays, with gas being the chief target.

2.4.1.1 State and MMS Administered Lands

The state of Alaska and MMS administered lands include the onshore area between the Colville and Canning Rivers and the state and OCS waters of the Beaufort and Chukchi Seas (Figure 2-1). Most of this region, with the notable exception of the Chukchi Sea, has been available for leasing for at least 25 years (Table 2.2) and has experienced multiple sales, several episodes of exploration drilling, and generally well established procedures and regulations. The Chukchi Sea was not opened to leasing until 1988 (Table 2.2) and has seen only one episode of drilling, but otherwise it can be viewed as being somewhat similar to the Beaufort Sea in regard to operating conditions, leasing stipulations, lead-time from discovery to production, and infrastructure requirements.

2.4.1.1.1 Colville-Canning Province and State Waters of the Beaufort Sea

The Colville-Canning province and the adjacent state waters of the Beaufort Sea remain the most active exploration area of the North Slope**. The bulk of the area is under state ownership, but ASRC controls approximately 3,000,000 acres in the Brooks Range foothills**

and has holdings in the Colville delta area. The exploration and development history has been discussed in an earlier section. This area accounts for virtually all current oil production and more than 95% of the known gas resources of the North Slope. The major oil fields include the Prudhoe Bay, Kuparuk, Endicott, Pt. McIntyre, Milne Point, and Alpine fields. Prudhoe Bay and Point Thomson fields contain the largest gas accumulations. All of these fields are in the northern area, on or near the Barrow arch and between the Colville and Canning Rivers.

Currently, exploration and development activities are divided between this area and the eastern portions of NPRA, with the bulk of development activity focused on satellite and other small, near-infrastructure oil accumulations. **Within the general Colville-Canning area and adjacent state waters of the Beaufort Sea, the future of near-term exploration is dependent to a great extent on decisions regarding ease of access to infrastructure for new operators and the construction of a gas pipeline.**

The drilling and general exploration plans for the near future (2009 winter drilling season) were summarized by the Petroleum News (PN, 2008b). Anadarko plans to complete the Chandler well in the Brooks Range foothills, drill a second well at Gubik (both on ASRC lands), and drill a well at Wolf Creek in NPRA. All three wells are targeting gas. Brooks Range Petroleum Corp. plans to drill as many as three wells in the Gwydyr Bay area at their North Shore and Sak River prospects. Chevron will return to the White Hills area and continue the drilling program they commenced in 2008. ENI has plans to pursue development drilling at their Nikaitchuq offshore unit in the shallow state waters of the Beaufort Sea. ExxonMobil, despite legal issues with the state, has plans to drill exploration wells in the Point Thompson field (PN, 2008b).

The approach to future exploration will be largely controlled by the proximity to infrastructure and the regional understanding of the petroleum geology of the area and sequential discovery of hub or anchor fields and the smaller satellites that depend upon them for economic viability. Source rock distribution and character as well as nature of reservoir and adequacy of traps/seals will be the primary geological drivers for the continued exploitation of the regions hydrocarbon resources. The type of hydrocarbon will be largely determined by the nature and thermal maturity of the source rocks; therefore, considerable emphasis is placed on the source rock character and geographic distribution.

The primary source rocks of the Shublik and Kingak are absent east of Prudhoe Bay in the northeastern portion of the area, but the Condensed Radioactive Shale (HRZ) is present across the entire area. From the Colville delta to the eastern limits of the Prudhoe Bay field and the source rock intervals are thermally immature with respect to generation of oil or gas (Bird, 1994: Figure 21.8). Here the R_o values are less than 0.6%. Figure 2-7 displays the zones of thermogenic petroleum generation and destruction, with the oil generation window occurring between 0.6 and approximately 1.3% vitrinite reflectance (Ro). The oil floor is at a Ro value of 1.35%.

In the southern Colville-Canning area, the Shublik and Kingak are deeply buried and no longer are capable of generating oil, and the southern portion of the region tends to be a gas-prone province. The southern limit of oil generation for the Kingak and Shublik occurs at the

1.3% R_o contour on Figure 21.8 of Bird (1994). This contour trends diagonally southeastward across the area from about 69º 20' north latitude to approximately 69º north latitude.

The Pebble Shale, HRZ, and Torok are present across much of the northern Colville-Canning area, but they are thermally immature for both oil and gas over much of the northern portion. Magoon and Bird (1985) and Magoon and Bird (1987) provide maps depicting contours of Ro values for the base of the Pebble Shale unit and the top of the Torok Formation. These maps bracket this package of Lower Cretaceous source rocks and demonstrate that currently the bulk of the sedimentary package is thermally immature for oil or gas generation north of about 70º north latitude. The top of the oil generation window shifts southward in the younger units and the 0.6% Ro value at the top of the Torok generally occurs south of 69º 30' north latitude and in places as far south as 69º. Thus, in much of the area the in-situ Lower Cretaceous source rocks did not make a significant contribution to known and unknown resources. Pebble Shale, HRZ, and Torok oils in the northern area probably migrated from the deeper portions of the Colville Trough to the south.

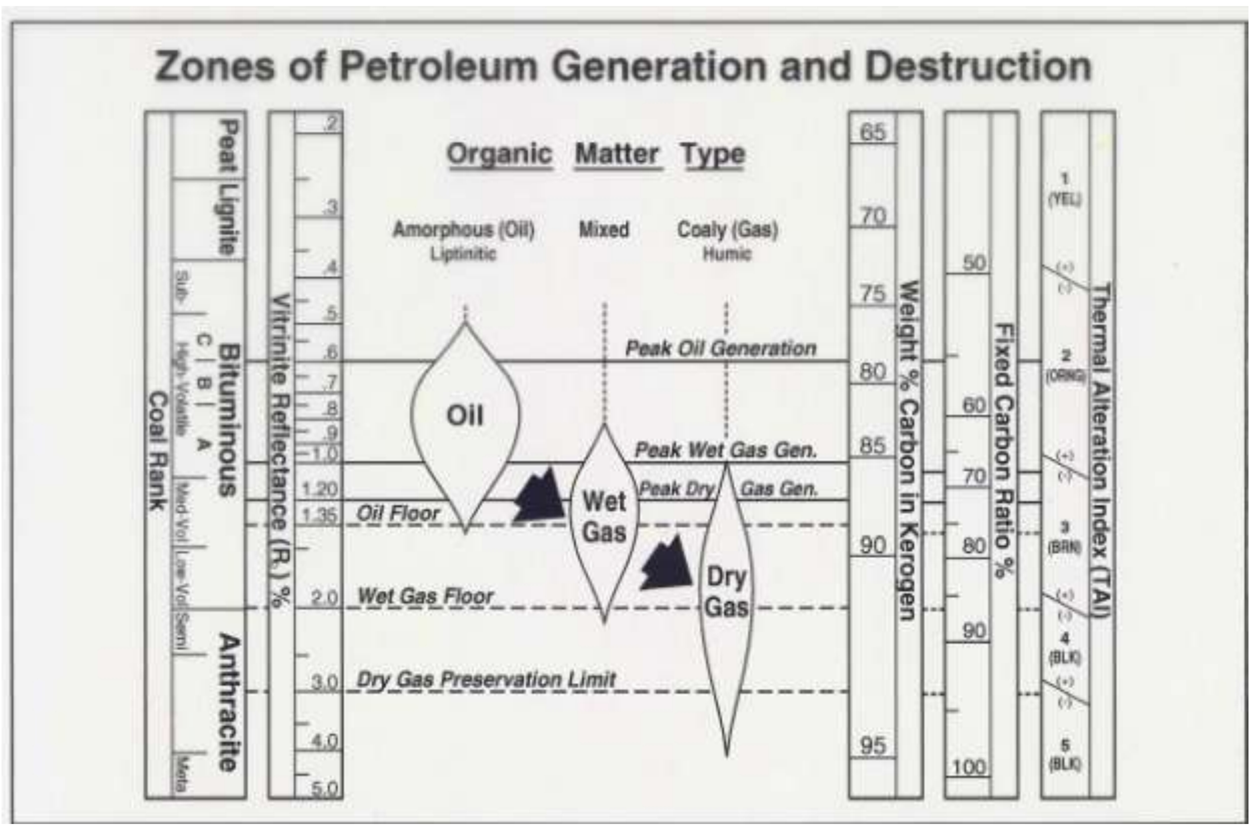

Figure 2-7. Correlation of coal rank scale with several petroleum maturation scales, showing zones of hydrocarbon generation and destruction. The vitrinite reflectance (Ro) scale is most commonly used (Source: Dow, 1977).

Prior to examining the possible reserve additions and the activity necessary to discover them it is important to review estimates of the magnitude of the potential undiscovered resources. **Table 2.13** summarizes the estimates of the hydrocarbon potential of the area in question. The Colville-Canning and state Beaufort Sea areas have not historically been evaluated as a discrete entity as have ANWR and NPRA. The estimated resources/reserves for these state areas were grouped with the federal lands to yield an estimate for the entire North Slope. The starred (*) estimates in the first row of **Table 2.13** represent the 1990 USGS slope-wide estimates minus the 1987 ANWR and 1980 NPRA estimates. There were no economically recoverable estimates by the USGS for ANWR and NPRA at that time, and consequently no "adjusted" Colville-Canning and adjacent Beaufort Sea economically recoverable values are presented.

Table 2.13. Estimates of hydrocarbon volumes -- State of Alaska lands North Slope, Alaska. Estimates originally presented included NPRA and ANWR assessments.

Source of Estimate	Estimate Format	Oil (BBO)			Gas (Nonassoc.) (TCF)		
		95%[a]	Mean	5%[a]	95%	Mean	5%
USGS 1990 revisions	Risked undiscovered technically recoverable	2.2 1.3*[b]	12.6 7.1*	35.4 20.8*	8.6 ???*	54.1 ???*	157.4 ???*
USGS 1995	Risked undiscovered economically recoverable	0.00 ???*	7.7 ???*	26.7 ???*	23.3 ???*	63.5 ???*	124.3 ???*
USGS 2005[c]	Risked undiscovered technically recoverable	2.6	4.0	5.9	23.9	33.3/(4.2[d])	44.9

a. 95% probability level means that statistically there are 19 in 20 chances that the resources are as great as or greater than the volume indicated, and the 5% probability level refers to a 1 in 20 chance that the resources are as great or greater than the estimated volume.
b. The numbers with an * reflect the non-federal lands estimates determined by extracting the appropriate estimates for NPRA and ANWR.
c. USGS 2005 numbers are for the Central North Slope state and native lands and the state shallow Beaufort Sea.
d. Associated gas.

Figure 2-8 presents stratigraphy, petroleum systems, petroleum plays and a summary of the ages, names, and rock types present in the Central North Slope assessment area.

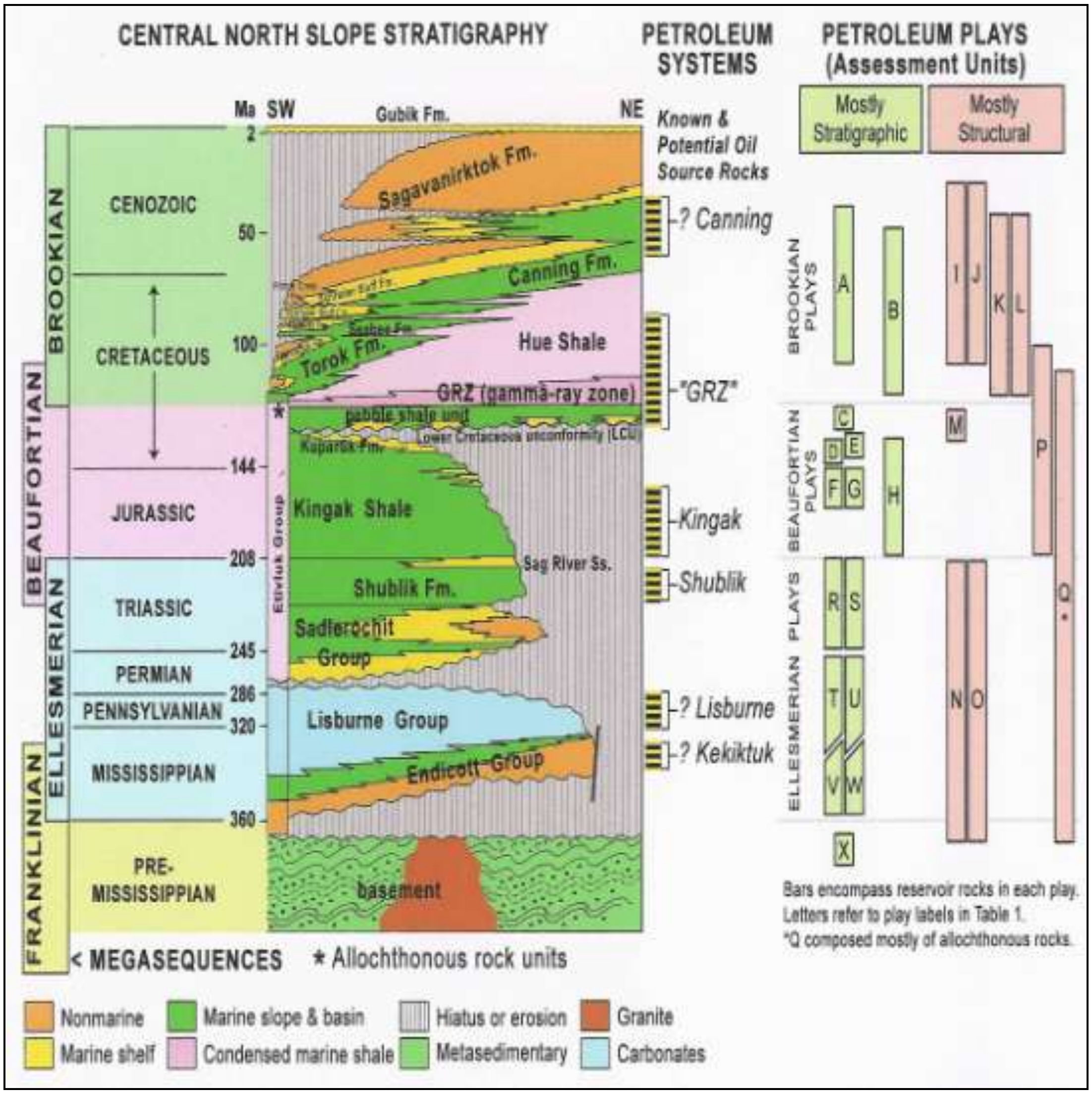

Figure 2-8. Summary of ages, names, and rock types present in the Central North Slope assessment area. Colored bars at the right show the stratigraphic position of the 24 petroleum plays evaluated in the 2005 assessment. Letters on the colored bars refer to the plays of Garrity et al. (2005), Table 1.

The following listing (Table 2.14) identifies the 24 plays evaluated in the 2005 assessment shown in Figure 2-8:

Table 2.14. Central North Slope petroleum plays in the 2005 assessment (from Figure 2-8).

Key	Petroleum Play	Key	Petroleum Play
A.	Brookian Topset	M.	Beaufortian Structural
B.	Brookian Clinoform	N.	Ellesmerian Structural
C.	Kemik-Thomson	O.	Basement Involved Structural
D.	Beaufortian Kuparuk Topset	P.	Thrust Belt Triangle Zone
E.	Beaufortian Cretaceous Shelf Margin	Q.	Thrust Belt Lisburne

Key	Petroleum Play	Key	Petroleum Play
F.	Beaufortian Upper Jurassic Topset East	R.	Triassic Barrow Arch
G.	Beaufortian Upper Jurassic Topset West	S.	Ivishak Barrow Flank
H.	Beaufortian Clinoform	T.	Lisburne Barrow Flank
I.	Brookian Topset Structural North	U.	Lisburne Barrow Flank
J.	Beaufortian Topset Structural South	V.	Endicott Truncation
K.	Brookian Clinoform Structural North	W.	Endicott
L.	Brookian Clinoform Structural South	X.	Franklinian

The most recent assessment of North Slope oil and gas resources was released in mid-2005 (Bird et al., 2005). This assessment pertains to the Central North Slope (Colville-Canning province) and the adjacent offshore area. These are nonfederal, state of Alaska and native corporation lands. The 2005 assessment (Bird et al., 2005) considers oil, associated gas, nonassociated gas, and NGLs. These estimates are presented as risked undiscovered technically recoverable resources and are shown in part inTable 2.17 (Bird and Houseknecht, 1998). The oil resources are estimated to range from 2.6 to 5.9 BBO and have a risked mean of 4.0 BBO. Nonassociated gas resource estimates range from 23.9 to 44.9 TCF and have a risked mean of 33.3 TCF. The mean associated gas estimate is 4.2 TCF. The risked mean for the NGLs is 478 MMBO.

There are two other areas of state lands within the “3-mile” limit of the Beaufort Sea. The area west of the Colville River was assessed as a portion of the 2002 NPRA (Bird and Houseknecht, 2002) assessment. These values are incorporated within the estimate for the ENTIRE AREA in Table 2.16 (Bird and Houseknecht, 2002). Similarly the state offshore areas east of the Canning River are included in the estimate for the ENTIRE AREA portion of the 1998 assessment of ANWR in Table 2.17 (Bird and Houseknecht, 1998). These areas are included in the discussions below even though the potential magnitude of resources is included in other assessments (Bird and Houseknecht, 1998 and 2002).

The 2005 assessment (Bird et al., 2005) involved the recognition and analysis of 24 plays (Figure 2-8). Approximately two-thirds of the oil or 2.5 BBO are expected to be found in three plays in the northern portion of the assessment area. The most prospective appear to be the Brookian Clinoform, Brookian Topset, and Triassic Barrow Arch plays (plays B, A, and R of Figure 2-8) with means of 1.6 BBO, 0.44 BBO, and 0.4 BBO respectively. The mean resources of the Early Cretaceous sandstones of the Kuparuk River Formation (play D), Kemik Sandstone (play C), and the Point Thomson Sandstone (play C) and the Brookian Topset Structural North (play I) provide an additional 690 MMBO; thus, these seven plays total approximately 3.19 BBO or 76% of the estimate for the Central North Slope assessment (Bird et al., 2005).

As anticipated, results of the 2005 assessment placed the bulk of the gas resources in the southern portion of the Colville-Canning province. Four plays (B, P, Q, and O of Figure 2-8) are believed to contain 50% of the nonassociated gas. In the order of plays presented above, the primary plays and the risked mean recoverable gas resources are Brookian Clinoform (6.44 TCF), Thrust Belt Triangle Zone (3.84 TCF), Thrust Belt Lisburne (3.59 TCF), and Basement Involved Structure (3.02 TCF). These plays have an aggregated mean of 16.9 TCF.

Four additional plays, Kemik-Thomson (play C), Brookian Topset Structural South (play J), Brookian Clinoform Structural South play K), and Beaufortian Structural (play M), have estimated means between 2.0 and 2.5 TCF and total 9.4 TCF. The aggregated means of these eight plays comprise 80% of the assessment area's mean recoverable gas.

The northern plays are primarily oil with associated gas. Prudhoe Bay is a prime example and Point Thomson may be looked upon as an extreme case of this association. The southern or foothills plays are largely nonassociated gas plays with some possibility of oil. East Umiat and Gubic are examples of these gas accumulations.

Northern Colville-Canning and State Beaufort Sea: For the purposes of this report the northern portion of the Colville-Canning area extends from the coast south to approximately 69º 25' north latitude or to the southern limits of the Alaska North Slope areawide sales region. Under virtually any likely scenario, the northern portion of the Colville-Canning area and the shallow Beaufort Sea will continue to be a focus of exploration and development activity for the next decade. It is anticipated that the major producers will continue to add production through the discovery and development of smallish satellite oil fields and new medium-size accumulations. Recently active small to intermediate size companies are expected to continue to explore acreage that is proximal to infrastructure and develop new fields, such as the recent finds at Oooguruk and Nikaitchuq **(Figure 2-4)**. These opportunities are present both onshore and in the shallow nearshore state waters of the Beaufort Sea.

The Ellesmerian reservoirs of the Mississippian Endicott and Lisburne Groups **(Figure 2-9)** and the Triassic Ivishak Formation will continue to be exploration objectives but much of the emphasis will shift to the younger Beaufortian and Brookian sections. The Beaufortian Upper Jurassic Alpine and related sandstones and Early Cretaceous Kuparuk Formation, Kemik Sandstone, and Point Thomson Sandstone equivalents **(Figure 2-10)** and the Brookian Late Cretaceous and Tertiary Schrader Bluff, Prince Creek, Sagavanirktok and Canning Formations **(Figure 2-11)** will tend to be the focus of future exploration efforts for oil.

As summarized above by Bird and Houseknecht (2005) identified the primary oil plays as the Brookian Clinoform (Torok/Seabee/Canning Formations), Brookian Topset (Nanushuk/Tuluvak/Schrader Bluff/Prince Creek/Sagavanirktok Formations and "equivalents"), and the Triassic Barrow Arch (Ivishak/Shublik/Sag River Formations). The Early Cretaceous topset units of the Kuparuk River Formation, Kemik Sandstone and Point Thomson Sandstone have a combined mean of 427 MMBO and are attractive secondary targets.

The major Ellesmerian and Beaufortian reservoirs in the Prudhoe-Kuparuk area are present throughout the north-central and northwestern portions of the region but are absent in the northeast due to erosion associated with the Lower Cretaceous Unconformity (LCU). The reservoir quality and thickness of the Ellesmerian and Beaufortian reservoirs decrease to the south and some units, notably the Beaufortian reservoirs, were deposited and preserved nonuniformly across the prospective area. The Brookian reservoirs are widespread across both the Colville-Canning area and the shallow Beaufort Sea and provide numerous stratigraphic targets.

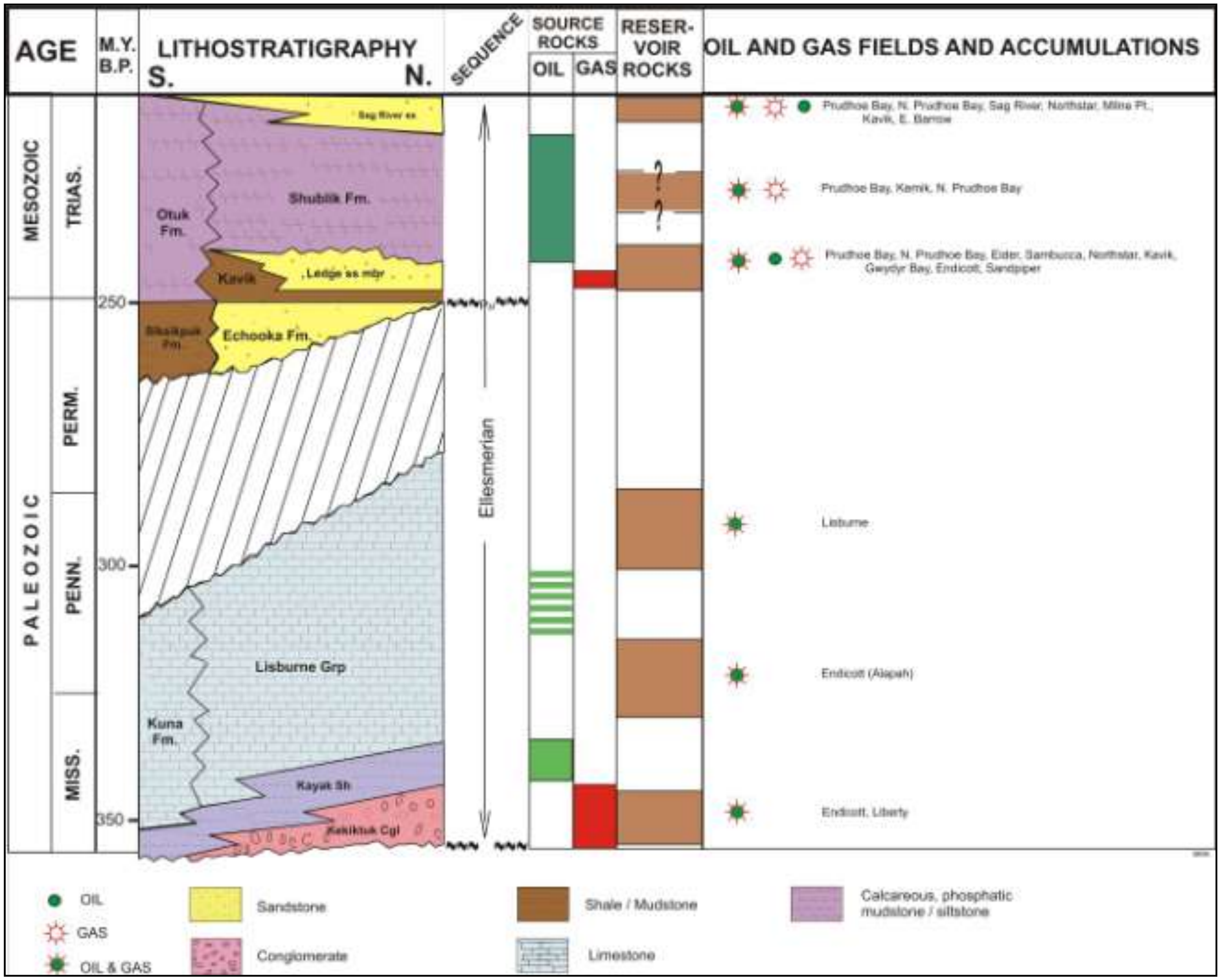

Figure 2-9. Ellesmerian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names.

(Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

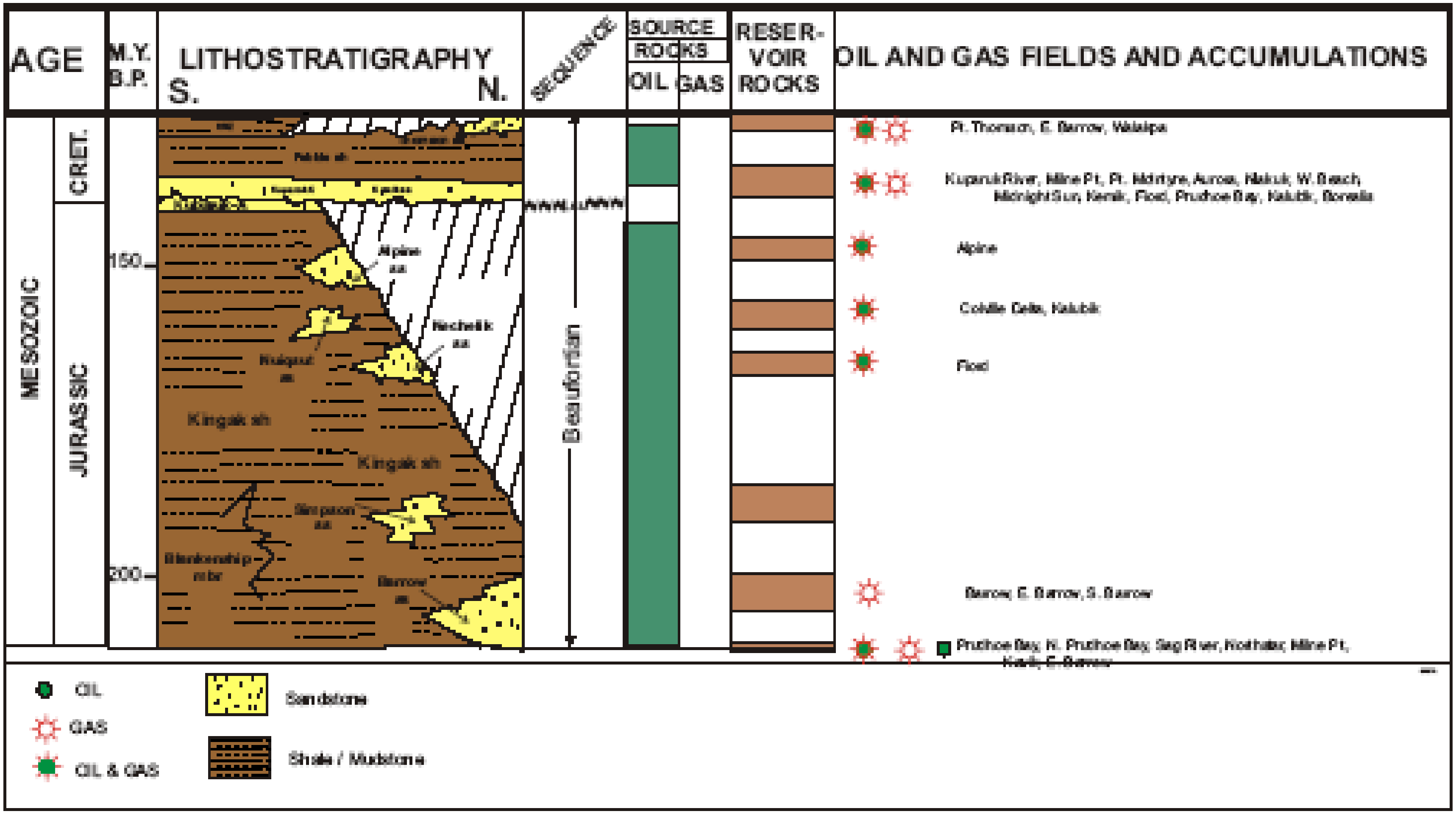

Figure 2-10. Beaufortian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names.

(Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

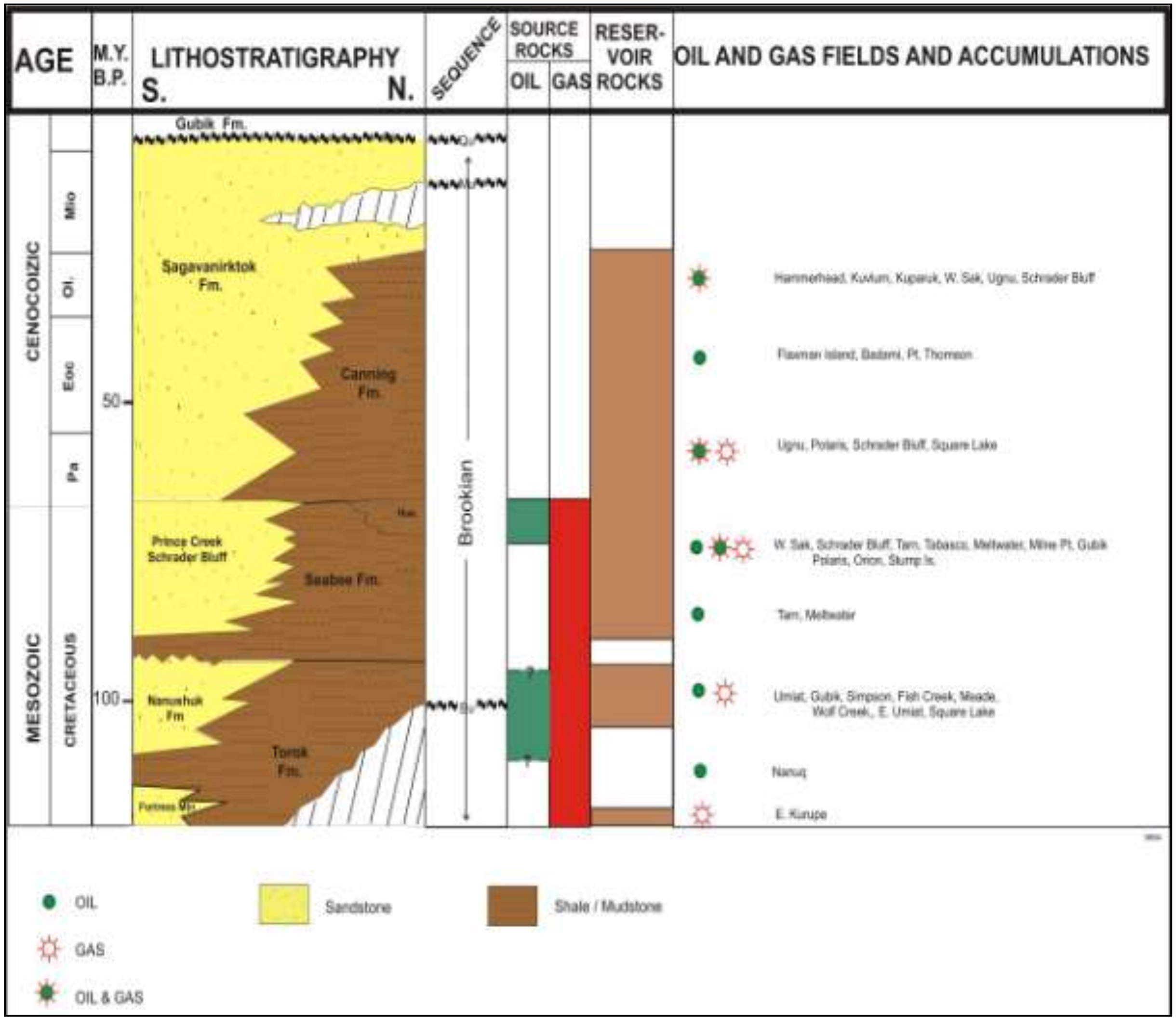

Figure 2-11. Brookian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names.

(Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

Based on the distribution and character of the various reservoir and source rock intervals, the hydrocarbon potential of the northern Colville-Canning area and the state shallow Beaufort Sea area varies considerably in the level of prospectivity. Of the 24 plays recognized in the USGS 2005 assessment (Bird et al., 2005) 16 plays are present either wholly or partially in the oil-prone northern Colville-Canning area and adjacent shallow Beaufort Sea. Only one play, the Brookian Clinoform, is estimated to have more than 500 MMBO of technically recoverable oil. Two plays, the Brookian Topset and the Triassic Barrow Arch, have between 250 and 500 MMBO. However, there is considerable areal overlap and potential vertical stacking of reservoir horizons, which provides the opportunity for multiple targets. Thus, a number of the less prospective plays may be evaluated and contribute to the reserve base as secondary or tertiary objectives.

In this area the pending level of exploration activity is relatively easy to assess. The major operators are not pursuing aggressive exploration programs. They have developed a low-risk, reserve-addition philosophy that entails exploration or extension drilling within a few miles of the existing production and transportation infrastructure. The emphasis is frequently on exploiting small accumulations that can be developed from existing pads and infrastructure through the application of extended reach horizontal drilling and multilateral completion technologies.

Since 2005, the activities of the major producers have resulted in reserve additions reflecting the addition of production from Fiord and Nanuq. The potential development of Sambucca is still to occur and the expansion of the heavy oil operations are in process. These activities may be expected to bring proven, economically recoverable resources of more than 250 MMBO on line by 2010. Fiord and Nanuq commenced production in 2006 and are expected to reach a peak of 35,000 BOPD in 2008 (PN, 2005).

In 2005, BP Exploration (Alaska) restarted the Badami oil field for a three-year period to test new recovery techniques (PN, 2005b). Prior to the restart, production was suspended in early 2003 and the field had been in warm shutdown. The EUR for this field is uncertain but probably less than the original estimate of 120 MMBO. An estimated revised EUR of 60 MMBO (Table 2.5) has been assumed for this report. This value is based on the assumption that the operators must see an economic benefit to producing the field and that reserves of this magnitude would be required to justify the continued effort to develop and produce the oil. Production rates for Badami were approximately 1,500 BOPD in December 2005, but the field was shut in again in September 2007, after producing an additional 851,355 barrels. In July 2008, it was announced that BP and Savant Alaska LLC would cooperate to drill additional wells to bring Badami back to production and perhaps expand the field (PN, 2008j). The AOGCC issued a drilling permit in January 2009 for Savant to drill a Badami exploration well (PN, 2009b).

The major operators will continue exploring around the fringes of the known large accumulations, and further satellite drilling and development may be expected to add an additional 100 to 150 MMBO of economically recoverable oil by 2015. Additional prospects in the Brookian Clinoform and the Upper Jurassic Topset East will be targeted and at least one success in range of 150 MMBO is anticipated.

The more recent arrivals to the North Slope are also leasing and drilling features in close proximity to the infrastructure. Kerr-McGee completed two offshore exploration wells in the state waters of the Beaufort Sea. These wells reflect a continuation of recent drilling focus within the Colville-Canning area**. The existing discoveries attributed to Kerr-McGee, Pioneer, and Armstrong at Oooguruk, Nikaitchuq, Tuvaaq, and in the Gwydyr Bay area are either now producing (Oooguruk) or are expected to be developed in the next one to three years and will add more than 200 MMBO of economically recoverable oil to the existing reserve base.**

Over the next five years exploration by these companies and other smaller independent operators will probably result in two small discoveries with a total of 50 to 75 MMB of economically recoverable oil. These discoveries are anticipated to be within 20 miles of existing infrastructure and to occur in Alpine, Kuparuk, **Ivishak/Sag River,** and Schrader Bluff reservoirs as either single or multiple horizon fields. **Two small discoveries (North Shore and Tofkat) were announced in the general Gwydyr Bay area in early 2007 (PN, 2007d).** Development and production of their existing resource base is probably a precondition for any effort to venture into more frontier or higher risk areas. It is anticipated that this will occur in the latter half of the coming decade or after 2010.

Other leased acreage in the area south of the Barrow Arch trend is prospective. The smaller companies and other "new to the North Slope" operators will drill attractive prospects in these areas **during the 2008 to 2018/2020 timeframe**. Targets include horizons ranging from the Mississippian Endicott Group to the Lower Tertiary Canning and Sagavanirktok Formations. Two economic discoveries, each in the 100 to 150 MMBO range, are expected to be found within 10 to 25 miles of infrastructure.

In summation, cumulative additions to production from known but as yet undeveloped or under-developed fields are anticipated to total 450 MMBO. **As yet undiscovered "reserves" that should be discovered and developed by 2018/2020 are expected to total 650 MMBO; thus, providing a total addition of approximately 1.1 BB of economically recoverable oil.**

There is no expectation for an exploration program directed exclusively for gas in the northern portion of the Colville-Canning province or the adjacent state waters in the Near-Term period.

Southern Colville-Canning Area/Brooks Range Foothills: The state and ASRC owned lands south of 69º 25' north latitude comprise the southern portion of the Canning-Colville area **(the North Slope Foothills areawide lease sale area of Figure 2-4).** Based on the character and history of the source rock sequences, this area is viewed as gas-prone. With respect to the Shublik and Kingak, the area south of the 1.3% Ro contour is a zone of predominantly wet gas, and farther to the south a realm of dry gas. There are a number of outliers of Kingak and Shublik, south of this gas-generation line, which have anomalously low Ro values and suggest that there is at least local potential for oil generation and accumulation in this otherwise gas-dominated area.

In a typical transect from north to south, increasingly greater portions of the Lower Cretaceous interval are within the oil generation window and enhance the probability that oil may have been generated in these younger rocks and accumulated in reservoirs of the Lower Cretaceous and overlying portions of the section. In fact, oil stained sandstones are not uncommon in the Torok and Nanushuk exposures within the foothills belt. However, the limit of oil preservation for the Pebble Shale Unit, the 2.0% Ro contour of Magoon and Bird, (1987, Figure 8) trends east-southeast across the area from 69º north latitude to about 68º 20'. Thus gas is the predominant hydrocarbon phase south of the 1.3% Ro contour and should be the sole phase south of the 2.0% Ro contour.

In support of the USGS assessment (Bird et al., 2005), Anadarko Petroleum Corporation has estimated that there are technically recoverable resources of 0.5 to 2.5 BBO and 20 to 40 TCF (Nelson, 2002) in the Brooks Range Foothills Belt of the Colville-Canning area.

Bird and Houseknecht (2005) have identified 15 plays with mean recoverable gas resources in the range of 0.5 to 6.5 TCF. Thirteen of the 15 plays occur predominantly in the southern portion of the assessment area. The four most important gas plays occur in the southern portion of the Colville-Canning area. One play is estimated to have mean recoverable resources of more than 6.0 TCF (Brookian Clinoform) and three have more than 3.0 TCF (Thrust Belt Triangle Zone, Thrust Belt Lisburne, and Basement Involved Structural) (Figure 2-8). While some gas opportunities exist in the north they are probably not of sufficient size to motivate exploration by companies seeking to establish proven reserves prior to the completion of the gas pipeline, **now assumed to be about 2018/2020.**

The southern portion of the Beaufortian Clinoform play is present over nearly the entire portion of the assessment area south of 69º 30' north latitude and includes reservoir horizons ranging from the Fortress Mountain/Torok package through the Canning Formation. The Thrust Belt Triangle Zone play occupies a gently concave northward arc largely south of 69º north latitude and north of 68° 30' north latitude. The reservoirs are principally Brookian and include Kingak through the Nanushuk/Torok horizons. The Thrust Belt Lisburne play is situated south of the Triangle Zone play and includes potential reservoirs ranging from the Endicott equivalents through the Nanushuk/Torok package. The Basement Involved Structural play occupies the southeastern to eastern portion of the assessment area and trends northeastward parallel to ANWR boundary as far north as the truncation limits of the Ellesmerian sequence. The prospective reservoirs are all Ellesmerian and range from the Endicott to the Ivishak.

Bird and Houseknecht (2005) predict that 96% of the undiscovered nonassociated gas resources occur in accumulations smaller than 3.0 TCF. The estimated accumulation size is believed to be conservative and the authors anticipate a greater total resource and generally somewhat larger accumulations**.**

Gas exploration was predicted to commence about 2009 and to be focused in the foothills area. In actuality, it began in 2008 with the wells at Gubik and Chandler prospects. At this writing, the Gubik well was being tested and the Chandler had been suspended prior to reaching the objective horizon(s) and will be reentered and deepened in

2009. Anadarko has estimated that the general area of these two wells plus the "Umiat" prospect has the potential to hold between 2 and 10 TCFG (PN, 2008h).

Two major discoveries are expected prior to 2012 with economically recoverable gas estimated to be 2.5 TCF (Lisburne or Torok/Nanushuk) and 5.0 TCF (Torok/Nanushuk). These accumulations are expected to be between 30 and 60 miles west of the pipeline corridor. The most appropriate reservoir analogs would be the Lisburne field at Prudhoe Bay and the Gubik or Umiat fields. Two to three smaller (0.5 to 1.5 TCF) fields totaling 2.5 TCF may be found by **2018/2020,** probably from the same or similar reservoir **horizons**.

The forecast is for economically recoverable gas totaling 10.0 TCF to be discovered, but not produced until potential start-up of the pipeline in 2018/2020. Gas production could commence within one year of the projected start-up of the gas pipeline.

2.4.1.1.2 Beaufort Sea and Chukchi Sea OCS Areas

The federal OCS areas of the Beaufort and Chukchi seas are administered by the MMS and hence have similar administrative, leasing, and environmental policies and regulatory structure. However, they have, at least locally, rather dissimilar stratigraphy and hydrocarbon prospects. The most recent update of the evaluations of these areas was performed in 2000 (MMS, 2000) but the key documents are Scherr and Johnson (1998) and Sherwood et al. (1998b).

Estimates of resource volumes, for variously ranked pools (Scherr and Johnson, 1998; Sherwood et al.., 1998b) in both the Beaufort and Chukchi seas, were presented as a combination of oil and gas charge within each pool. There are three possible distributions of these resources. The traps are either: (1) filled with oil, (2) filled with gas, or (3) contain one of a nearly infinite number of possible gas-to-oil ratios. The MMS is now abandoning this approach and in the future will represent these data with some form of billions of barrels of oil equivalent presentation. For the purposes of this report, plays will be represented by pool (field) sizes expressed as either 100% oil or 100% gas.

Recent activities by Shell and ConocoPhillips, plus others have demonstrated the continuing and expanding interest in the OCS areas of the Chukchi and Beaufort Seas. The large size of the total winning bids in the recent Chuckchi lease sale, seismic acquisitions in both areas, and plans to drill in the Beaufort Sea are all strong signs of expanding and vigorous interest and exploration activity (PN, 2008m).

Beaufort Sea OCS Area: Exploration of the Beaufort OCS will most probably continue to be centered in those areas offshore from currently developed infrastructure and target conventional (structurally defined) oil plays and/or the areas near existing but as yet undeveloped discoveries (**Sivulliq** and Kuvlum).

The Beaufort Sea OCS Lease Sale 195, held in March 2005 provided the first indications of the directions in which offshore activity may be initially focused during the near-term. Sale 195 offered approximately 9.4 million acres in 1,800 blocks. The sale resulted in 121 tracts totaling 250,400 acres being awarded to the high bidders. **This new leasing**

suggests that operators retain a substantial interest in both the area and the variety of plays known to have oil potential.

Twenty-three plays have been identified in the Beaufort Sea OCS region by the MMS (Scherr and Johnson, 1998) (Table 2.15), with aggregated mean undiscovered recoverable resources of 8.84 BBO and 43.50 TCF. The revisions that occurred subsequent to this assessment placed a portion of the western Beaufort Sea assessment area in the Chukchi shelf assessment province and resulted in the revised estimates of the National Assessment Update (MMS, 2000) (Table 2.15), with mean risked undiscovered technically recoverable resources of 6.9 BBO and 32.1 TCF.

The plays in the Beaufort Sea are associated with the same general stratigraphy that is present onshore, but the pre-LCU units of the Ellesmerian and Beaufortian are restricted to the southern and generally central portions of the shelf. Thus the reservoirs and source rocks, most responsible for the reserves and production in the Prudhoe Bay – Kuparuk area, are limited in distribution to the south-central portion of the shelf. The younger (post-LCU) reservoirs and source rocks generally have shelf-wide distribution. These latter units include the upper Kuparuk River Formation or Kuparuk C sandstone which postdates LCU and is the reservoir in the Point McIntyre, Niakuk, West Beach, and Midnight Sun fields (Figure 2-4).

The revised Beaufort shelf assessment province has approximately 15 plays ranging from Pre-Mississippian "basement" objectives to Tertiary targets. Four of these plays have estimated mean recoverable oil of approximately 1.0 BBO or more (Scherr and Johnson, 1998). These are the Beaufortian Rift play – 0.91 BBO (Kuparuk River Formation and Jurassic Kingak Shale sandstones – fields include the Kuparuk and Alpine), the Brookian Faulted Eastern Topset play – 1.05 BBO (Sagavanirktok – shows in the Galahad well), the Brookian Unstructured Eastern Topset play – 1.65 BBO (Sagavanirktok – fields include the West Sak and Ugnu onshore and **Sivulliq** and Kuvlum offshore), and the Brookian Foldbelt play – 2.04 BBO (Sagavanirktok and Canning Formations – tested by the Corona, Belcher, and Aurora wells, located north of the 1002 Area).

Table 2.15. Estimates of hydrocarbon volumes: Beaufort Sea and Chukchi Sea OCS areas.

Year of Estimate	**Source of Estimate**	**Assessment Area**	**Estimate Format**	**Oil (BBO)**			**Gas (TCF)**		
				95%	**Mean**	**5%**	**95%**	**Mean**	**5%**
1987	Mast et al. (1989, tbl. A2)	Beaufort Sea	Risked, Conventionally Recoverable	0.49	1.27	3.74	2.14	8.26	12.81
1987	Mast et al. (1989, tbl. A4)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	0.21	1.74	0	0	0
1987	Cooke (1991, tbl. 4)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	0	0.38	1.84	0	2.38	11.48

Year of Estimate	Source of Estimate	Assessment Area	Estimate Format	Oil (BBO)			Gas (TCF)		
				95%	Mean	5%	95%	Mean	5%
1990	Cooke (1991)	Beaufort Sea	Risked, Conventionally Recoverable	Conventionally Recoverable Resources Not Re-Calculated in 1990 Update-See 1987 Estimates					
1990	Cooke (1991, tbl. 1)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	0.38	2.63	0	0	0
1990	Cooke (1991, tbl. 3)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	0	0.67	3.33	0	2.45	10.17
1995	Scherr and Johnson (1998, tbl. 14.1)	Beaufort Sea	Risked, Conventionally Recoverable	6.278	8.835	11.965	20.101	43.502	79.148
1995	Craig (1998, tbl. 27.11)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0.72	2.27	4.44	0	0	0
1995	Craig (1998, tbl. 27.12)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	Not Reported	3.223	Not Reported	Not Reported	0	Not Reported
2000	MMS (2000, tbl. 1)	Beaufort Sea	Risked, Conventionally Recoverable	3.56	6.94	11.84	12.86	32.07	63.27
2000	MMS (2000, tbl. 2)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	1.78	6.64	0	2.93	9.68
2000	MMS (2000, tbl. 3)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	1	3.24	7.76	0.64	4.2	10.67
1987	Mast et al. (1989, tbl. A2)	Chukchi Sea	Risked, Conventionally Recoverable	0	2.22	7.19	0	6.33	16.87
1987	Mast et al. (1989, tbl. A4)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	0.59	3.59	0	0	0
1987	Cooke (1991, tbl. 4)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	0	1.03	5.79	0	2.52	13.92

Year of Estimate	Source of Estimate	Assessment Area	Estimate Format	Oil (BBO)			Gas (TCF)		
				95%	Mean	5%	95%	Mean	5%
1990	Cooke (1991)	Chukchi Sea	Risked, Conventionally Recoverable	Conventionally Recoverable Resources Not Re-Calculated in 1990 Update-See 1987 Estimates					
1990	Cooke (1991, tbl. 1)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	1.36	8.76	0	0	0
1990	Cooke (1991, tbl. 3)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	0	1.69	10.65	0	4.46	27.55
1995	Sherwood et al. (1998, tbl. 13.14)	Chukchi Sea	Risked, Conventionally Recoverable	6.801	13.015	21.943	9.808	51.84	141.754
1995	Craig (1998, tbl. 27.11)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	1.14	4.48	0	0	0
1995	Craig (1998, tbl. 27.12)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	Not Reported	2.845	Not Reported	Not Reported	0	Not Reported
2000	MMS (2000, tbl. 1)	Chukchi Sea	Risked, Conventionally Recoverable	8.6	15.46	25.03	13.56	60.11	154.31
2000	MMS (2000, tbl. 2)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	0.97	7.2	0	0	0
2000	MMS (2000, tbl. 3)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	1.42	6.11	10.96	0	0	0

The Beaufortian Rift, Brookian Faulted Eastern Topset, and Brookian Unstructured Eastern Topset plays are the most easily accessible and attractive of the Beaufort Sea OCS plays. The Beaufortian Rift play formations have proved to be highly productive at Kuparuk, Milne Point, Point McIntyre and other smaller fields and are among the active exploration targets in eastern NPRA and the State onshore and offshore lands. These plays are located offshore from the Colville-Canning area and have the potential for “relatively” easy access to the onshore infrastructure. The Brookian Unstructured Eastern Topset play overlies the Rift play and also contains large volumes of oil in the West Sak and Ugnu fields onshore. The Faulted Eastern Topset play prospects are also relatively proximal to existing infrastructure. The Brookian Faulted Eastern Topset play exists seaward of the unstructured topset play in deeper waters.

While the target intervals are the same as in the unstructured topset play only one well, the Galahad located northwest of Kuvlum (Figure 2-4), has tested this play concept.

The fourth play, the Brookian Foldbelt play, is located offshore from ANWR and would be extremely difficult to explore and develop without access to onshore facilities within ANWR and thus is probably not a likely target in the near term.

Of the other 11 plays, only the Upper Ellesmerian or Sadlerochit play has an estimated mean of more than 0.5 BBO; however, in the 5% case it is estimated to have greater potential than the Rift or Faulted Brookian plays (Scherr and Johnson, 1998). Since it underlies both the Beaufortian Rift play and the Eastern Brookian Unstructured plays, it is likely that this play would be tested in any well drilled to evaluate those shallower objectives.

Prospects on the outer shelf portions of Beaufort OCS will not be primary targets until shallow water, near shore prospects have been proven to be economically developable or in the rare instance where the possibility of a very large discovery is compelling enough to support the risk. The Beaufort OCS offshore from the western portions of NPRA and ANWR will not be exploration targets during the next decade unless significant onshore discoveries have been made in adjacent portions of NPRA, or ANWR has been opened to exploration and development.

For the near term, exploration in the Beaufort OCS will most likely be confined to the relatively shallow portions of the Beaufort shelf and restricted largely to that portion of the shelf between Harrison Bay and the mouth of the Canning River (see Figure 2-4). Exploration wells will be drilled with multiple objectives and test Brookian through upper Ellesmerian target horizons. The 1995 assessment, as presented by Scherr and Johnson (1995 and 1998), provides estimates for the three plays (Upper Ellesmerian, Beaufortian Rift, and Brookian Unstructured Topset) ranging from 1.61 to 7.27 BBO with a mean of 3.32 BBO. **With respect to gas, the assessment of these three plays (Scherr and Johnson, 1995 and 1998) includes a range of 2.1 to 14.8 TCF with a mean of 5.2 TCF. While adding gas reserves will not be a primary objective during the next decade, it is highly probable that the discovery of oil will carry with it some quantity of gas.**

OCS Lease Sales 195 and 202 (Figure 2-5) largely confirmed the continuation of the recent leasing and drilling patterns. The Sale 195 drew single bids on 121 tracts for a total of 618,751 acres (MMS, 2005). The great bulk of the leases (85%) are located between Harrison Bay and Barter Island. Most of the leased tracts are just seaward of the 3-mile limit and lay between the Colville Delta and Prudhoe Bay. Nine tracts were leased north of Smith Bay, about 40 miles east of Barrow and nine east of the Kaktovik Deferral area, approximately 20 miles west of the Canada border. Leases containing the **Sivulliq** and Kuvlum oil accumulations were acquired by Shell in that sale. Approximately half of the leases are contiguous with existing leased tracts and in part expand the holdings of the lessees. The MMS is quoted as interpreting the sale results to indicate that the plays targeted in the sale were Brookian plays and chiefly the Brookian Unstructured Eastern topset and Brookian Foldbelt plays (PN, 2005c), which are two of the four most attractive plays in the area. **Sale 202 resulted in the issuance of 90 leases totaling 490,492 acres in much the same areas that received bids during Sale 195 (Figure 2-5).**

If the next decade replicates the drilling activity (three exploration wells) of the previous 10 years, drilling in the Beaufort OCS will be minimal and two to four wells may be expected. **At this juncture there are indications that activity will increase because of renewed interest in the area on the part of Shell and the reports that Shell was purchasing rigs to drill in the Beaufort OCS (PN, 2006). Shell did purchase two rigs for this work but has since released them. In mid-2007 the courts placed an injunction on Shell's Beaufort Sea drilling activities previously approved by MMS (PN, 2007g). Shell plans to appeal the court's decision and has announced plans to defer its 2009 Beaufort Sea drilling program until 2010, given a favorable resolution of the current itigition (PN, 2008t).**

The major North Slope operators have not shown much interest in the OCS recently and are concentrating on satellite development and their limited exploration activity is focused on eastern NPRA. The smaller newly active companies, operating in the Colville Delta to Prudhoe Bay area, are exploring for small to moderate size accumulations in close proximity to infrastructure and have rarely ventured into the OCS. The sole exception is Armstrong, which acquired seven leases in OCS Sale No. 186 adjacent to their existing State leases and acquired 20 adjacent leases in OCS Sale No. 195. Higher levels of activity are possible if more companies become involved in exploration on the North Slope and adjacent waters. The presence of more competitors tends to lead to greater diversity in play concepts and risk taking.

The anticipated near term exploration results are the discovery of one small to moderate size accumulation (100 to 500 MMBO) with one or two productive intervals, presumably the Kuparuk River Formation and the Sadlerochit or Endicott. To be a commercial success, depending on location, the field would probably need to have 300 to 500 MMBO of economically recoverable oil. Five hundred billion to a trillion cubic feet of gas could be expected to be associated with such a discovery. Additionally, two to four small satellite-like fields from the same group of reservoir horizons are to be expected with potential economically recoverable resources of 50 to 100 MMBO each. These discoveries are expected to occur within 5 to 20 miles of the shoreline.

The results of these efforts are expected to be 650 MMBO (a total of four discoveries) and approximately 1.0 TCF of economically recoverable resources.

With Shell's acquisition of leases that include the Hammerhead/Sivulliq feature and the purchase of two drilling vessels capable of working in the Beaufort Sea, drilling was initially planned for 2007; however, law suits have delayed the planned drilling until 2010 at the earliest. Shell was also the apparent high bidder on the acreage over the known Kuvlum accumulation, but these bids were rejected by the MMS as inadequate. The Kuvlum acreage did not receive bids in Sale 202. If these structures and Wild Weasel are drilled in the next two to five years and additional reserves are found and developed these fields could account for at least 500 to 600 MMBO. It is doubtful that production would commence prior to 2018.

Chukchi Sea OCS Area: The MMS has recognized 22 plays in the Chukchi Shelf Assessment Province (Sherwood et al., 1998) with aggregated unrisked undiscovered technically recoverable means of 13 BBO and 51.8 TCF (Table 2.15). Revisions completed in 2000 (MMS, 2000) increased these estimates to 15.5 BBO and 60.1 TCF. These revised estimates largely reflect the redefined boundaries of the Chukchi and Beaufort shelf assessment provinces. The redefinition of these provinces transferred the area west of Point Barrow from the Beaufort shelf to the Chukchi shelf assessment province.

Seismic data and the limited exploration drilling in the Chukchi Sea have documented the presence of virtually all the reservoir intervals found in the Prudhoe Bay area, plus potential reservoirs of the pre-Mississippian Franklinian sequence. The presence of the major source rock intervals of the Shublik Formation, Kingak Shale, and Pebble Shale have been documented by drilling.

A second series of lease sales was planned with the first sale scheduled for 2003, but it was cancelled due to apparent lack of interest. Subsequently, the MMS released a reevaluation of the Burger gas discovery (Craig and Sherwood, 2005), and the unrisked mean resources in the most likely case are 14.04 TCF and 724 million barrels of NGLs (MMB). The risked mean values are 9.48 TCF and 489 MMB. The magnitude of these estimates provides encouragement for the future of exploration in the Chukchi Sea,

Based on the results of the Burger reevaluation and the renewed interest in the potential of the area, OCS Sale 193, held in February 2008, was a huge success. High bids in the sale totaled nearly $2.7 billion for 488 tracts with 2,758,408 acres (Table 2.2). This level of investment strongly suggests that the high bidders have plans to proceed with the exploration and potential development of the Chukchi Sea area earlier than anticipated.

In the original writing of this report, it was thought that until exploration and development within NPRA reach the western portions of NPRA and the gas pipeline was built there was no market or economic incentive to explore for and develop the resources of the Chukchi Sea. Consequently, it was expected that no significant exploration and development would occur in the Chukchi Sea area until after 2015; thus, the plays and their character are presented in the long term (2018/2020 to 2050) potential portion of the discussion. However, there is now a high probability that additional exploration drilling will occur in the Chukchi Sea before 2015 and possibly as early as 2010.

2.4.1.2 Other Federal Lands

NPRA and the 1002 Area of ANWR are administered by different federal agencies, have experienced very different levels of evaluation and exploration, and are potentially prime areas of future exploration activity and development. However, the near term prospects for the two areas are markedly different. As has been shown, the NPRA is experiencing a successful leasing and expanding exploration drilling phase, with an encouraging level of success in the area west of the Alpine field.

2.4.1.2.1 National Petroleum Reserve Alaska (NPRA)

The NPRA is currently the second most active of the exploration domains in Arctic Alaska. The recent exploration and leasing activity in this area is reflected by the current lease holdings **(Figure 2-3)** and last **nine** years of exploration drilling shown on **Figure 2-6. The drilling activity since the original 2007 report was written includes three wells in 2005, one well in 2006, four wells in 2007, and none in 2008 (Figure 2-6).**

The BLM administers the NPRA, and the hydrocarbon resource assessments have been performed under the auspices of the USGS. The USGS 2002 assessment of the NPRA identified 24 plays. Bird and Houseknecht (2002) constructed a figure relating the stratigraphic section and the plays. It is reproduced here as **Figure 2-12.**

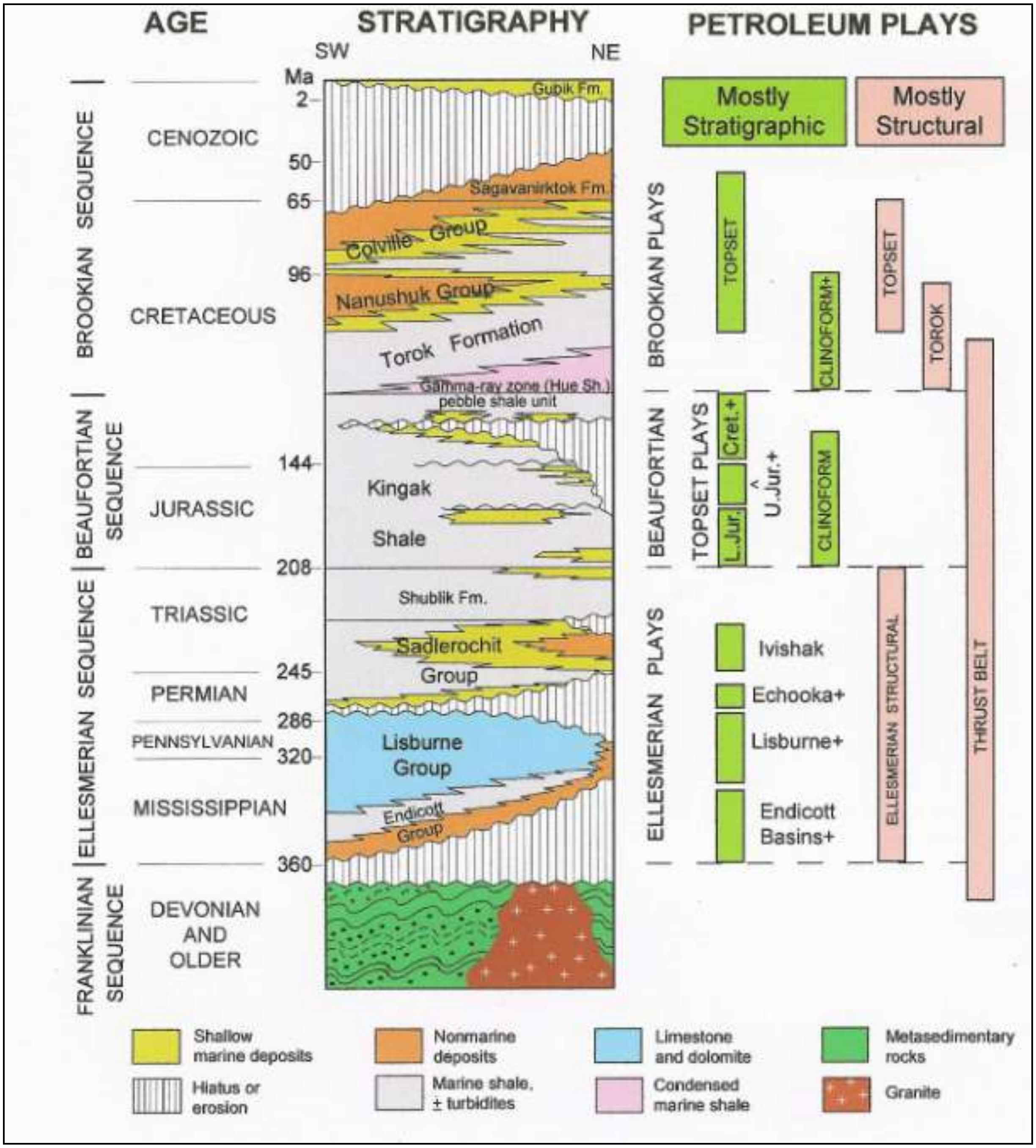

Figure 2-12. Summary of ages, names, and rock types present in NPRA.

Colored bars at right show the stratigraphic position of the 24 petroleum plays evaluated in the 2002 assessment (Source: Bird and Houseknecht, 2002). Note that the bars with a "+" symbol indicate multiple plays in different areas. Plays indicated by bold outlines include those with the greatest oil and (or) gas potential.

The reservoir horizons are similar to those of the Colville-Canning area, but the **equivalents of the** main reservoirs **that are productive** in the Prudhoe Bay and Kuparuk field area tend to be less well developed and are generally poorer quality. As in the Prudhoe Bay area, the Shublik, Kingak, and HRZ are the primary source rocks in NPRA (Houseknecht, 2003 and 2003b). The distribution of the Shublik and Kingak is less strongly controlled by the LCU and they are recognized to be present across the entirety of NPRA with the exception of the extreme northern portion, at Point Barrow (Bird, 1994, Figure 21.8). Flanking the small truncation area at Point Barrow is a narrow band of thermally immature Shublik/Kingak. For the Shublik and Kingak source intervals, the southern limit of oil generation trends southeast from 70º 15' north latitude along the Chukchi coast to about 69º 20' north latitude, north of Umiat. South and southwest of this limit, the area is predominantly a gas province.

The HRZ, the associated Torok Formation and the Pebble Shale units blanket the entire NPRA with source rocks of varying quality. Generally the HRZ is an excellent oil-prone source while the Torok and Pebble Shale are of somewhat lesser quality and locally are more prone to generate gas. The entire sedimentary package becomes more deeply buried and thermally mature to the south. Consequently, greater portions of the section have passed through the oil-generation window and into the gas-generation realm. The southern limits of oil generation is at approximately 69º north latitude and the interval is thermally immature for oil-generation north of a line trending southeast, subparallel to the Beaufort Sea coast, from 71º north latitude in the Point Barrow vicinity to 70º north latitude at the Colville River.

Most of the stratigraphic section, from the Lower Mississippian to the Lower Tertiary, is represented by one or more play types. Twenty of the 24 plays are stratigraphic. The seven Ellesmerian stratigraphic plays (Figure 2-12) include the Mississippian Endicott and Lisburne Groups, the Permian Echooka Formation and the Triassic Ivishak Formation. The Echooka Formation has not been an exploration target in the Colville-Canning area. There are eight Beaufortian stratigraphic plays (Figure 2-12) consisting of a cliniform or turbidite play, Jurassic Kingak topset plays, and Cretaceous Kuparuk topset plays. The five Brookian stratigraphic plays (Figure 2-12) are primarily clinoform or turbidite plays in the Cretaceous Torok and topset plays in the Cretaceous Nanushuk through Tertiary Sagavanirktok interval. Several of the stratigraphic plays exist as "multiples" in different geographic areas (Bird and Houseknecht, 2002).

The structural plays (Figure 2-12) include a thrust belt play that incorporates Mississippian through Early Cretaceous units, an Ellesmerian structural play that involves Mississippian through Triassic strata, an Early Cretaceous Torok play, and an Early to Late Cretaceous topset play.

The USGS has periodically performed assessments of the oil and gas potential of NPRA for over a quarter of a century. The estimated mean technically recoverable volumes have increased with each assessment (**Table 2.16**) as more and better data, backed by discoveries in the Colville-Canning area, have revealed the generative potential of the source rocks and the presence and character of prospects in an ever increasing variety of stratigraphic intervals and trapping situations.

Table 2.16. Comparison of USGS assessments, from 1976 to 2002, of the hydrocarbon resources of the NPRA. (ENTIRE AREA includes federal and native lands and the state offshore areas).

Agency/Year	Estimated Technically Recoverable Hydrocarbon Resources					
	Oil (BBO)			Gas (TCF)		
	95 %	Mean	5%	95 %	Mean	5%
U.S. Geol. Survey/1976	1.0	1.9	3.0	3.2	6.3	10.6
U.S. Geol. Survey/ 1980	0.3	2.1	5.4	1.8	8.5	20.4
Bird and Houseknecht, 2002 (NPRA ONLY)	5.9	9.3	13.2	39.1	59.7	83.2
Bird and Houseknecht, 2002 (ENTIRE AREA)	6.7	10.6	15.0	40.4	61.4	85.3

The most recent assessment resulted in an aggregated mean for technically recoverable oil of 10.565 BBO with a range of 6.7 to 15.0 BBO and for gas 61.35 TCF with a range of 40.4 to 85.3 TCF. Bird and Houseknecht (2002: Table 1) provide estimates of technically recoverable oil and nonassociated gas for each of the 24 NPRA plays evaluated in the 2002 assessment.

Of the 24 plays, only four are deemed to have mean technically recoverable oil resources of approximately 1.0 BBO or greater. These are the Beaufortian Upper Jurassic topset plays (Alpine-like) in the northwest (1.86 BBO) and northeast (5.18 BBO) planning areas and the Brookian Lower Cretaceous clinoform/turbidite (Tarn-like) plays of the north (1.31 BBO) and central (0.98 BBO) portions of the NPRA (Figure 2-12). The Upper Jurassic northwest and northeast topset plays occur in a 60-mile wide belt that trends southeast across NPRA subparallel to the Beaufort Sea coastline and south of Smith Bay. The Brookian clinoform plays trend nearly east-west across NPRA and are present over the northern half on NPRA.

The Upper Jurassic topset plays of the northeastern area are estimated to have mean technically recoverable reserves of 5.2 BBO or approximately half of the recoverable oil assigned to NPRA in Table 2.11 of the 2002 assessment. The same play type in the northwestern area is given a mean of 1.9 BBO. These two Alpine-Nuiqsut-Nechelik play trends account for a total of 66.7% of the estimated aggregated mean technically recoverable oil for the assessment area. The means for the Brookian clinoform/turbidite plays total 2.28 BBO with 1.3 BBO for the north set of plays and 0.98 BBO for the central trend for an additional 21.6% of total estimated technically recoverable oil.

In summation, these four plays are considered to represent more than 88% of the technically recoverable oil in NPRA. If these numbers represent a reasonably sound proportional distribution of expected volumes, the primary reservoir formations of the Prudhoe Bay-Kuparuk area are not stand-alone objectives and have little potential to contribute to the resource-base in NPRA. Similarly, the structural plays would seem to have little oil potential with an aggregated mean of only 0.18 BBO. Eight of the plays are considered to have no technically recoverable oil in the mean case (Bird and Houseknecht, 2002: Table 1).

Six plays have mean technically recoverable gas resources of 3.0 TCF or greater (Bird and Houseknecht, 2002). Four are stratigraphic plays, the Beaufortian Upper Jurassic topset in both the southwest and southeast and Brookian clinoform/turbidite plays in the central region and the deep portions of the southern area. These plays are generally located just south of the oil-bearing belt of plays. The mean technically recoverable estimates for the Upper Jurassic topset southwest and southeast plays are 5.22 and 5.14 TCF, respectively. The Brookian clinoform south-deep has an estimated mean of 3.79 TCF and the clinoform central play has an estimated mean of 5.41 TCF. The total mean resources for these plays are 19.56 TCF or approximately 32% of the aggregated mean recoverable gas.

Structural plays represent a major portion of the gas potential in NPRA. The Torok and Brookian topset structural plays have mean recoverable gas volumes of 17.91 and 10.61 TCF, respectively. Summed, these two structural plays have 28.52 TCF or 46.5% of the aggregated mean gas resources for NPRA. The six plays listed here represent more than 60% of the estimated mean gas potential of the NPRA.

The estimates for associated gas presented in the USGS 2002 assessment (Bird and Houseknecht, 2002) may require an upward revision for at least one and possibly two plays. Drill stem tests in the northeast area have yielded daily flow rates of 6.6 to 26.5 MMCF from recent wells evaluating Beaufortian Upper Jurassic topset northeast plays (PN, 2004m). These same wells tested high gravity oil at rates of 320 to 4,000 BOPD. The USGS 2002 assessment did not identify any gas resource potential in either the Upper Jurassic northeast or northwest topset plays.

Based on these estimates and knowledge of the geology of the area, it is most probable that exploration efforts over the next decade will continue to be focused on the Upper Jurassic sandstones (Alpine, Nuiqsut, and Nechelik) of the Kingak Formation and Brookian clinoform/turbidite plays (Tarn and Tabasco). The Kokoda No. 1 and Kokoda No. 5 wells **(Figure 2-6)** were drilled during the 2005 drilling season to evaluate Brookian turbidite plays.

Since 2004, only two groups have been actively exploring within the NPRA. Their moderately successful efforts have been in close proximity to Alpine and associated satellites. Much further from Alpine, in NPRA's Northwestern Planning Area, a total of five exploration wells have been drilled by ConocoPhillips and FEX, with four by FEX. The most remote well was drilled by ConocoPhillips, about 20 miles south-southwest of Barrow (Figure 2-6). To date no economic discoveries have been reported in the northwestern planning area.

It can be expected that exploration drilling will continue to focus on Beaufortian topset and Brookian turbidite plays to the west and southwest, in an ever-widening search. If the exploration drilling activity remains at current levels, it would be reasonable to have 20 to 25 additional exploration wells drilled by 2018/2020. Given that activity level, the discovery of two moderately sized oil fields may be expected, with economically recoverable oil in the 250 to 500 MMB range. An additional four to six 50 to 100 MMBO small or satellite fields should be anticipated. These discoveries can be expected to be made within 25 to 75 miles of the existing infrastructure at Alpine. These fields could provide a total of 0.7 to 1.5 billion barrels of additional recoverable oil added to the reserve base by the year 2018. An "average" would be approximately 1.1 BBO. Production should begin within three to five years of discovery and successful delineation.

Significant volumes of associated gas would be a by-product of oil exploration during this time frame but obviously no commercial production would occur. The quantity of gas that might be discovered while pursuing the currently favored oil plays is uncertain. The MMS assigns very little probability of gas to the Beaufortian plays in the northeast and northwest planning areas (Bird and Houseknecht, 2002), but gas flow-rates from recent wells have been as high as 25.0 MMCFD. Therefore, it is reasonable to expect continued exploration of these trends to involve the discovery of some large volumes of gas. Resource additions of 1.0 trillion cubic feet or more of associated gas are possible. Current thinking assigns the bulk of the NPRA nonassociated gas resources to the southern portions of NPRA, and these areas are unlikely sites for exploration until a gas pipeline is approved and the builders are committed to or proceeding with the construction of the line.

2.4.1.2.2 1002 Area of Arctic National Wildlife Refuge (ANWR)

The 1002 Area of ANWR has long been considered to be one of the most prospective portions of Arctic Alaska. However, due to its current status as a portion of ANWR it is not open to exploration and development. The only oil and gas directed activities have been the two seismic acquisitions seasons in 1984 and 1985 and the single well drilled on ASRC inholdings in 1986.

The FWS administers the Refuge but the hydrocarbon resource assessment has been performed by the USGS. **Table 2.17** displays the historical evolution of resource assessments for the 1002 Area. The key point to recognize is that as more information has become available the understanding of the resource potential of the area has evolved and the assessment of the volume of technically recoverable oil has increased from a mean of 2.53 BBO in 1986 (Hanson and Kornbrath, 1986) to a mean of 7.67 BBO in 1998 (Bird and Houseknecht, 1998). The entire assessment area, which includes state and native corporation land, has a mean technical ultimate recovery (TUR) of 10.3 BBO (Table 2.17), and the mean OOIP is 27.778 BBO. The mean nonassociated OGIP volume is estimated to be 5.12 TCF and the mean technically recoverable volume is 3.841 TCF. The mean OGIP for associated gas is estimated to be 13.4 TCF and mean technically recoverable associated gas is 4.75 TCF. The sum of OGIP is 18.5 TCF and mean recoverable gas is 8.59 TCF.

Table 2.17. Historical estimates of hydrocarbon resources in the 1002 Area of ANWR. (ENTIRE AREA includes federal and native lands and state offshore areas)

Source	Oil-in-Place (BBO)			TUR (BBO)
	95 %	Mean	5%	Mean
Mast et al., 1980	0.2	4.9	17.0	????
Hanson and Kornbrath, 1986	0.08	7.3	26.5	2.53
Dolton et al., 1987	4.8	13.8	29.4	3.23
Bureau of Land Mgmt. 1991	????	????	????	3.57
Gunn, 1992	????	23.3	49.5	6.97
Bird and Houseknecht, 1998 (1002 AREA of ANWR)	11.6	20.7	31.5	7.67
Bird and Houseknecht. 1998 (ENTIRE AREA)	15.6	27.8	42.3	10.3

Figure 2-13 was constructed (Bird and Houseknecht, 1998) to relate the 10 identified plays of the USGS's 1998 assessment to the stratigraphic section. While the subheading atop the lithologic column suggests the section represents a southwest to northeast transect through the 1002 Area, it actually is more representative of a section from the eastern plunge of the Sadlerochit Mountains northeast to the vicinity of the Niguanak high.

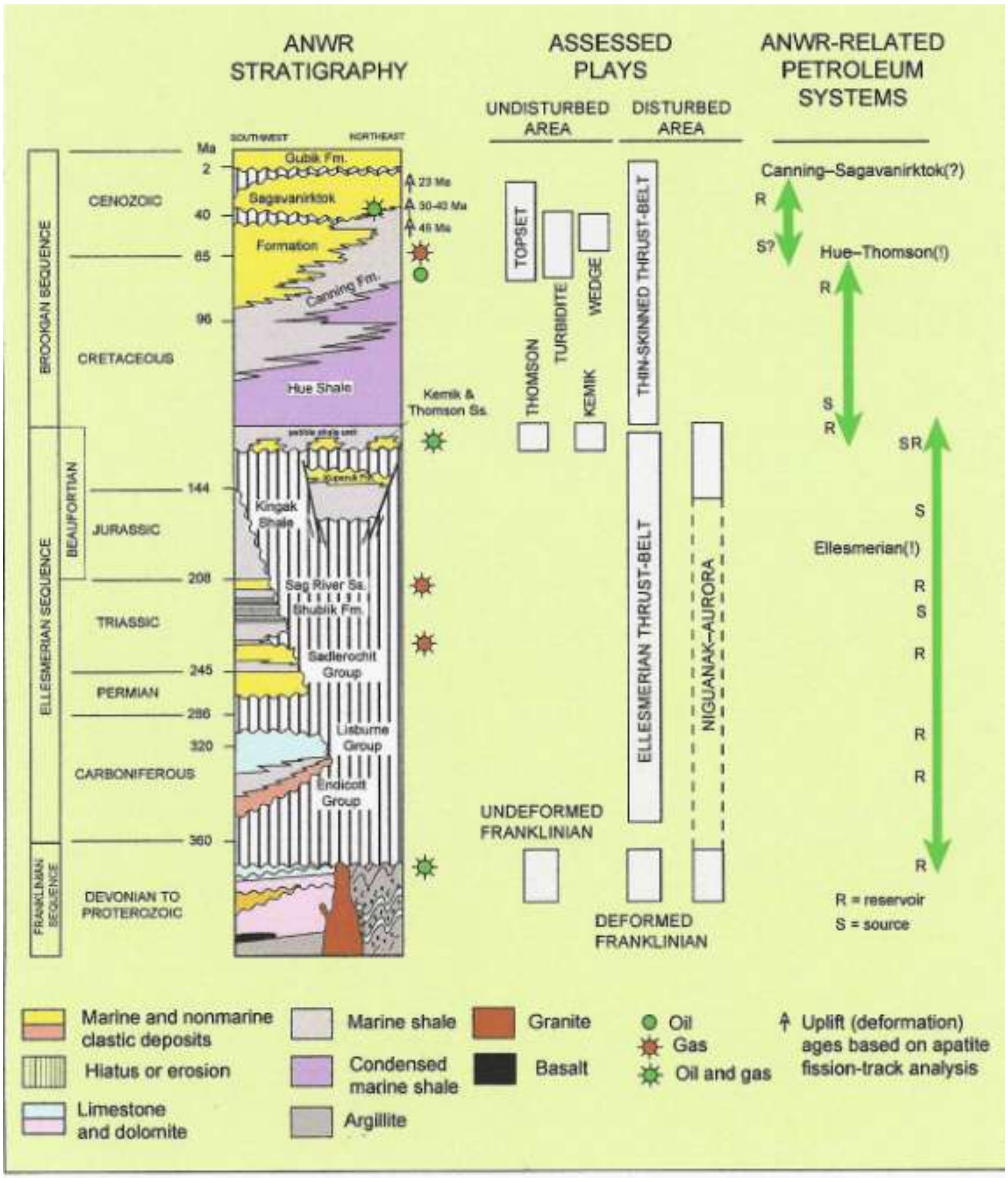

Figure 2-13. Summary of ages, names, and rock types present in the 1002 Area of ANWR. The occurrence of recoverable petroleum in these rock formations outside the 1002 Area is indicated by green and red circles. Gray bars at right indicate the 10 petroleum plays

assessed in the 1002 study and their corresponding rock formations (to the left). Note the grouping of plays according to deformed and undeformed areas (Source: Bird and Houseknecht, 1998).

The variety of reservoir and source rocks of the 1002 Area are both similar and dissimilar to what in found to the west in the Colville-Canning province. Erosion associated with LCU has removed the entire Ellesmerian sequence and most of the lower Beaufortian sequence from the western portion of the 1002 Area, and the upper-most Ellesmerian and the entire Beaufortian are absent due to erosion in much of the eastern part of the area. As a consequence the Kingak Shale plays a minor role as a source rock, but the Hue Shale, Mikkelsen Tongue of the Canning Formation, and probably the Shublik are viable source rocks for the area **(Figure 2-13)**.

The reservoir rocks of the Ellesmerian and lower Beaufortian sequences are absent in the west. In the eastern portion of the 1002 Area, the lower Beaufortian reservoirs are missing. Latest Beaufortian and Brookian reservoirs are present across the 1002 Area and the Ellesmerian reservoirs occur only in the extreme south and southeast portions of the 1002 Area (Figure 2-13). Potential Franklinian sequence reservoirs are expected to exist throughout the area but are of unknown quality and presumed to be primarily carbonates of the Katakturuk Dolomite and Nanook Limestone **(Figure 2-13)**.

There is still a great deal of uncertainty regarding the ultimate political outcome and when or if exploration and development may occur within the 1002 Area. Consequently, there are a number of scenarios that may be put forth regarding the future of oil and gas exploration and production. For the purposes of this report only two will be considered.

Scenario I, the efforts to open the ANWR 1002 area to exploration and development will fail and the 1002 Area of ANWR will become permanently closed to industry. As a consequence of this scenario there would be no further need to address the area in this or the following long-term section.

Scenario II is based on the assumption that the 1002 Area will be opened to exploration within the next 5 to 10 years. There many possible options for this scenario but the timeline proposed here for illustration is based on a 2010 approval. A later approval, up to a certain point in the future, simply moves the dates to accommodate the length of the delay in opening.

The Energy Information Administration (2002 and 2004) utilized the 1998 USGS assessment (Bird and Houseknecht, 1998) to establish a time line from approval date to exploration and development of 7 to 12 years. If it is assumed that approval is granted in 2010 that would mean development and accompanying production would most likely occur between 2017 and 2022. For this illustration, it is assumed that a minimum of 10 years are required to complete development. This scenario is envisioned to occur as follows:

- 2010–exploration and development in the 1002 Area approved
- Winter 2011/2012–acquisition of a high quality 2D program to compliment, enhance the utility of, and perhaps infill existing seismic control and delineate structural plays

- Winter 2012/2013–acquisition of 3D seismic programs to better delineate structures and to identify and delineate potential stratigraphic plays
- 2014–first lease sale in 1002 Area
- 2015 or 2016–first exploration drilling, along eastern side of Canning River and/or along the northern flank of the Marsh Creek anticline
- 2016 or 2017–first "economic" discovery
- 2017 or 2018–evaluation of first "economic" discovery
- 2019–field development commences
- 2022–first production from 1002 Area into TAPS

These sequential steps assume no inordinate delays due to litigation and that the time from discovery to the onset of production mimics Alpine, which required six years (1994 to 2000). Thus, the estimates of this report and that of the EIA of 7 to 12 years from approval to production are possibly on the conservative side. Since this time line places the first feasible production in the long-term category, the discussion of plays and possible 1002 Area exploration will be addressed more expansively in that section.

2.4.2 Long Term (2018/2020 to 2050) – Dual Oil and Gas Activity

The character of this phase of activity is largely dependent on the development of a gas pipeline that is capable of receiving and transporting large quantities of natural gas. The proposed capacity ranges between 4.5 and 6.0 BCFD. The 4.5 BCFD volume appears to represent the most likely case, with the ability to expand the capacity to something in the vicinity of 6.0 BCFD. With such a pipeline and the necessary supporting infrastructure in place or well into the construction phase, much of the effort will be directed to bringing known gas resources to production and exploring in frontier regions for additional gas resources. This is not meant to imply that oil exploration will cease, but that gas may assume an equal or primary role with respect to exploration drilling and expenditures in much of Arctic Alaska.

By **2018/2020** the areas most proximal to the current (**2008**) developments and their infrastructure will be largely explored and the more obvious features evaluated and developed. Exploration over the longer term will continue to expand outward from these core areas to take maximum advantage of and add to the in-place facilities and transportation systems. Sequentially, exploration activities can be expected to continue in the Colville-Canning province and adjacent state waters and eastern NPRA, with a well-defined shift from north to south as gas exploration increases. Secondly, given that exploration is approved in the 1002 Area of ANWR, exploration will expand as rapidly as possible into the coastal plain of ANWR. Thirdly, exploration within NPRA will move westward and southward, concurrent with an increase in the breadth of exploration in Beaufort Sea. **Fourthly, exploration activity in the Chukchi Sea will continue apace as a result of either exploration success within NPRA or based on the potential indicated by the Burger discovery and the high level of interest demonstrated by the results of the 2008 lease sale.**

2.4.2.1 State and MMS Administered Lands

These lands will continue to be explored for oil and now gas, because they are proximal to the existing oil and developing gas infrastructure. The active exploration halo will expand outward from the vicinity of the older fields and move southward into the gas prone regions of the southern coastal plain and the Brooks Range foothills. **Offshore, the areas of interest are expected to continue the trends followed during the 2008 to 2018/2020 episode, and to expand to both the east and west in the Beaufort Sea as well as farther offshore into the middle and outer portions of the shelf. In the Chukchi Sea, the entire eastern two-thirds of the shelf, in the vicinity of the 2008 leases (Figure 2-5) is considered to be an active exploration province given a nearby infrastructure and attractive price situation.**

2.4.2.1.1 Colville-Canning Province and State Waters of the Beaufort Sea

For the purposes of estimating the long term prospectivity and success, approximately 50 to 75% of the USGS estimates in the 2005 assessment (Bird et al., 2005), less the proposed success for the **2008 to 2018/2020** interval, are assumed to be found during the **period from 2018/2020** to 2030 and the remainder over the next twenty years. The greater degree of success is expected in the areas closest to existing infrastructure, with only about 50% of estimated resources found in the more remote and poorly explored portions of the area. **It should be remembered that the 2005 evaluation by Attanasi (see p. 2-59 of this addendum report) of the 1002 Area of ANWR, using an oil price indicated that 90% of the technically recoverable oil would be economic (Attanasi, 2005).** This general approach will also be utilized in the other areas of northern Alaska.

Northern Colville-Canning and State Beaufort Sea: Even 25 to 40 years into the future the plays of interest will be basically unchanged from those that have been the historical targets in this area. The most noteworthy exception would be the Brookian Foldbelt play to the east, offshore from the 1002 Area. This play is virtually undevelopable unless the adjacent portions of the 1002 Area have been opened to exploration and development.

Once again the primary oil exploration targets are Brookian Clinoform and Topset plays, plus the Triassic Barrow Arch play. The principal area for oil prospects in all of these plays is north of 70º north latitude. The eastern limit of the Triassic Barrow Arch play is at about 147º west longitude and the Brookian plays extend entirely across the area (Garrity et al., 2005). **Over the 30-plus years, from 2018/2020 to 2050, exploration of the northern portion of the Colville-Canning area should test virtually all identifiable prospects with economic potential.** The bulk of the discoveries are expected to occur prior to 2030.

The Brookian Clinoform prospects are anticipated to yield two fields of approximately 250 MMBO each and two others in the 100 to 150 MMBO range. These will be within 20 to 30 miles of existing infrastructure. At least three to five satellites are expected within the clinoform play with an average size of 50 MMBO. Both the Brookian Topset and Triassic Barrow Arch plays may be expected to yield a 150 MMBO field and two to three 50 MMBO satellites. In all three plays, the larger fields will probably be developed first with the satellites following later in the sequence of development. The economically recoverable volumes associated with these three plays are anticipated to total 1.5 BBO.

The Brookian Topset Structural North and Thomson plays are each expected to yield discoveries of commercial size. Each play should have a discovery of about 100 MMBO and a smaller field of 50 MMBO. The Beaufortian Kuparuk Topset, Beaufortian Upper Jurassic

Topset West, Brookian Clinoform Structural North, and perhaps the Lisburne Barrow Arch plays will provide additional upside opportunities as secondary and tertiary objectives and each can be expected to provide one to three accumulations in the 25 to 50 MMBO range. These smaller plays are expected to generate about 550 MMBO.

This level of success will result in an addition of approximately 2.05 BBO. **These fields can be expected to begin production as early as 2020 and be fully developed by 2035.** The continued efforts to improve recovery from the viscous oil accumulations of the Ugnu and West Sak (Schrader Bluff) may add equal if not greater volumes of oil reserves, but this aspect may more properly be addressed under the subject of reserve growth in a later section of the report.

Gas exploration and development in the northern portion of the Colville-Canning area will be limited. Most if not all gas discoveries will be associated gas and will be found as a by-product of oil oriented exploration activities. Bird et al. (2005) estimated mean undiscovered recoverable associated gas to be 4.2 TCF and to be principally associated with the Brookian Clinoform, Brookian Topset, Kemik-Thomson, and Triassic Barrow Arch plays. These plays are estimated to have 3.1 TCF or nearly 75 recent of the associated gas. The gas will be found as the oil exploration proceeds and may be produced late in the history of the individual fields. The largest associated gas accumulation is expected to be 0.5 TCF and found with the largest Brookian Clinoform oil accumulation. Once again 75% of the recoverable gas volume is expected to be economically recoverable; thus, for these four plays economically recoverable gas is estimated to total 2.3 TCF.

Southern Colville-Canning Area/Brooks Range Foothills: As stated earlier the southern Colville-Canning area is viewed by most observers as a gas-dominant province. The 2005 USGS assessment (Bird et al., 2005) suggests that the aggregated mean undiscovered technically recoverable oil is less than 500 MMBO. From a review of the limited play and prospect data available at the time of this report, it appears that no oil prospect/accumulation is expected to have more than 64 to 128 MMBO (the approximate size of the Umiat accumulation). This estimate is at or below the low end of the 500 to 2,500 MMBO potential proposed by Anadarko (Nelson, 2002). The 5% probability sum for the technically recoverable oil in the predominantly gas plays is 900 to 1,000 MMB and provides an upside for oil that one or more companies may find attractive enough to pursue.

Based solely on the USGS assessment, it is difficult to present a case in which oil is the primary exploration target. However, the Umiat field in or near the gas-prone region and the presence of the exhumed Torok “oil field” south of the Tuktu escarpment are proof that oil was generated and accumulated in this portion of the Colville-Canning province. **Dead oil in exposures of the Lisburne at Tiglukpuk anticline, in the Skimo Creek area along the front of the Brooks Range, and many other localities in the front ranges are further evidence that oil was generated, and at one time migrated into or through reservoirs in this area.**

The possibility of an accumulation in excess of 150 MMBO exists in at least two plays the Thrust Belt Triangle Zone (5% case = 217 MMB) and the Thrust Belt Lisburne (5% case = 250 MMB) (Figure 2-8, plays P and Q) predicated on the magnitude of the upper end of the potential resource distribution.

The primary gas plays and the mean recoverable resources in this area are the Brookian Clinoform (6.44 TCF), Thrust Belt Triangle Zone (3.84 TCF), Thrust Belt Lisburne (3.59 TCF), and Basement Involved Structural (3.02 TCF) plays. These four plays were assessed (Bird et al., 2005) to have slightly more than 50% of the aggregated mean for nonassociated recoverable gas (33.32 TCF). The probable reservoir horizons for each of these plays are indicated on Figure 2-8; plays B, P, Q, and O respectively.

The near-term (**2008 to 2018/2020**) exploration was estimated to have found 10.0 TCF of economically recoverable gas, primarily from the Brookian Clinoform and Thrust Belt Lisburne/Thrust Belt Triangle Zone plays. The remaining potential is assumed to be 20 to 25 TCF.

The USGS assessment (Bird et al., 2005) recognizes only one gas accumulation (Brookian Clinoform) with technically recoverable reserves in excess of 3.0 TCF and that accumulation was previously projected to be found during the near-term phase of exploration. Thus the remaining accumulations are expected to be equal to or less than 3.0 TCF.

The forecast is for an additional three accumulations averaging 2.5 TCF of economically recoverable gas with one each from the Lisburne Group, Torok/Nanushuk, and Sagavanirktok/Canning. These **potential fields** are considered to be discovered over a 10- to 15-year interval with the last one in 2030. They will be within 50 to 150 miles of the gas pipeline, and for the purposes of modeling are spaced equidistantly at 50, 100, and 150 miles. Five smaller fields, averaging 1.5 TCF, are expected to be found during this same time span and at similar distances from the pipeline. Similar reservoirs will be targeted. These larger fields are expected to contribute 15.0 TCF to the reserve base.

The smallest series of discoveries are anticipated to range from 0.5 to 1.5 TCF and average about 0.75 TCF or approximately the size of the Gubik gas field as it is viewed today. These will be targeted in the latter phase of exploration and only after the larger more economic accumulations have been discovered and developed. Thus, they will need to be in reasonable proximity to the infrastructure. These fields are assumed to be distributed among several reservoirs and to be associated with some of the lesser play types, principally the Brookian Topset Structural South (Nanushuk, Prince Creek, Tuluvak, and Sagavanirktok Formations), Brookian Clinoform Structural South (Torok, Seabee, and Canning Formations), Beaufortian Structural (Kuparuk/Kemik), and Ellesmerian Structural (Endicott, Lisburne, Sadlerochit groups). Approximately eight fields of this size are expected, with the first being discovered in 2016 and the last by 2040. These accumulations will be found within 10 to 20 miles of developed gas fields and total about 6.0 TCF.

The total gas additions of economically recoverable gas resulting from the long-term exploration effort in the southern portions of the Colville-Canning area are estimated to be approximately 21 TCF.

Additions to the oil reserve base are very uncertain. There is a possibility that a single economic accumulation could be found in close proximity to the existing oil pipeline. This would be a 125 to 250 MMB accumulation with some additional possibility of satellite development.

Summary: Economically recoverable oil resulting from the long-term exploration and development of new fields may be expected to add an additional 2.05 BBO to the ultimately recoverable reserves of the area. The development and implementation of new more efficient technologies for improving recovery from the heavy oil accumulations at West Sak and Ugnu may double or triple that expectation. Additionally, long-term exploration has the potential to add 21 TCF of nonassociated gas and 2.3 TCF of associated gas to the 35 TCF of proven reserves as **of January 1, 2008,** and the 10.0 TCF forecast to have been discovered between **2008 and 2018/2020.** The estimate of ultimate production from existing discoveries, reserve growth, and both near-term and long-term exploration success is tabulated in **Table 2.18** for the Colville-Canning area and the State Beaufort Sea waters. Reserves growth potential is discussed in Section 2.5.2 and included in this table for completeness. No reserves growth is indicated for gas, but with reserves growth in the major medium to light oil fields there will be a concurrent increase in the available gas (associated solution gas).

Table 2.18. Estimate of ultimate and cumulative production of oil and gas from Colville-Canning Area and State Beaufort Sea Lands.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/7	**15.687**	0.00*
ERR as of 12/31/07	**7.03-7.39**	35.00
Reserves growth in producing fields (12/31/07)	5.0-6.0	0.0
Near-term exploration success (2008 to 2018/2020)	1.10	10.0
Long-term exploration success (2018/2020 to 2050)	2.05	23.3
TOTALS	**30.77-32.23**	**68.30**

* 5.188 TCF has been used for lease operations and local sales to ANS North Slope utilities and pipelines, the balance of the total production of 55.418 TCF has been injected (ADNR, 2005).

Beaufort Sea OCS Area: The Beaufort Sea OCS area has the potential to provide significant additional reserves **(Table 2.19)**, if there has been timely and appropriate infrastructure development to accommodate more widespread onshore and shallow Beaufort Sea discoveries. Based on the discoveries to date and the assessments by the MMS, the Beaufort Sea OCS has the potential to add approximately 4.3 BBO and 20.0 TCF (approximately 60% of the revised assessments) **between 2018/2020 and 2050**, with the bulk of the oil expected to be discovered prior to 2030. Gas will not be a priority during the early phases of this longer term exploration effort but some quantity will be discovered as a by-product of the oil-oriented exploration. By 2025, gas exploration will probably have achieved a stand-alone exploration status.

Most of the additions to the oil side of the ledger are expected to come from the four plays discussed in Section 2.4.1, the near term section (Brookian Rift, Brookian Faulted Eastern Topset, Brookian Unstructured Eastern Topset, and Brookian Foldbelt) and the Upper Ellesmerian play, with lesser contributions from the Lisburne and various other Brookian plays (Scherr and Johnson, 1998).

Oil discoveries have been made in the Brookian Unstructured Eastern Topset (Kuvlum) and the Upper Ellesmerian (Northstar), demonstrating the viability of these plays. **From a discovery timing perspective, the 2018/2020 to 2050 discoveries and associated development**

will probably occur first in the Upper Ellesmerian, Rift, and Brookian Unstructured Eastern Topset plays. The timing of discoveries and specially development in the Brookian Faulted Eastern Topset and Brookian Foldbelt plays will lag behind the others because of their relative remoteness and political considerations.

Based on the MMS estimates of pool sizes (Scherr and Johnson, 1998) the larger "primary" fields should range from 350 to 1,450 millions of barrels of oil equivalent (MMBOE) and average about 700 MMBOE. Four fields of this magnitude (2.8 BBO total reserves) are assumed to be discovered. These discoveries are expected to be primarily from Rift and Brookian Eastern Faulted Topset plays. Approximately five to six secondary fields (1.1 BBO) with reserves ranging from 100 to 300 MMBO can be expected to be economic once the primary fields are developed. These secondary fields and an equal number of smaller satellites (50 to 100 MMBO) are assumed to be found in approximately equal proportions from the five main play types. These smaller fields (0.4 BBO), in close proximity to either the primary or secondary fields, will be discovered and developed in much the same fashion as the Prudhoe Bay and Kuparuk satellites are today.

In most instances, the primary and secondary plays should be within 25 miles of the coast line and from there accessible to the onshore transportation and processing infrastructure. The notable exceptions are Brookian Faulted Eastern Topset and Brookian Foldbelt plays. The Brookian Faulted Eastern Topset play is almost everywhere more than 25 miles offshore, and the Brookian Foldbelt play has the dual obstacles of lying offshore from the 1002 Area and about 50% of the play area is more than 25 miles from shore.

Due to the lack of applicable data or history, the major discoveries are assumed to occur once every two to four years with smaller fields occurring with about twice that frequency. The Rift and Upper Ellesmerian plays should be discovered first followed by the Brookian Eastern Topset and then the remaining plays. The lead time from discovery to first production is estimated to be seven to eight years in the Beaufort OCS. The additions of economically recoverable oil are expected to total approximately 4.3 BBO.

Due to economic considerations and the need to maintain the oil pipeline capacity, gas exploration, while potentially significant, will probably lag behind the continued search for oil, especially in areas relatively near the present oil handling infrastructure.

The major gas plays are generally the same as the oil plays with the addition of the Brookian Faulted Eastern Turbidite play. Scherr and Johnson (1998) estimate the Brookian Faulted Eastern topset play to have a mean value for risked undiscovered conventionally recoverable gas of 16.07 TCF. The Rift, Brookian Faulted Eastern Turbidite, and the Brookian Foldbelt plays have mean values that range from 2.5 to more than 3.5 TCF. The mean sizes of the larger gas prospects range from 5.0 to 8.5 TCF. The secondary accumulations range from 2.0 to 5.0 TCF, when traps are 100% filled with gas.

Discoveries in the first half of the 2018/2020 to 2050 time period are anticipated to be in the 0.5 to 2.0 TCF range in Rift (Kuparuk River) and Upper Ellesmerian (Sadlerochit) plays. The bulk of the gas will be discovered post-2030 as exploration moves offshore into the area of the Brookian Faulted Eastern Topset play and eastward into the area of the Brookian Foldbelt play, which lies offshore from the 1002 Area of ANWR. Three fields with mean gas resources between 2.0 and 7.0 TCF are expected to be discovered in the 15 to 20 years prior to 2040. These fields will most probably be found in the Brookian Faulted Eastern Topset and Brookian Foldbelt plays. The reservoirs are probably the Sagavanirktok and to a lesser extent the Canning Formations. An additional five, smaller 0.5 to 2.0 TCF, fields should complete the probable economically developable discoveries. The total estimated economically recoverable gas from these discoveries would be approximately 20 TCF.

Table 2.20 is presented to show the impacts of exploration on the reserve potential of the Beaufort OCS. Currently the only production in the Beaufort OCS is from the Northstar field and those volumes are included in Table 2.19.

These presumed discoveries, oil or gas, will require between 7 to 10 years to develop. The variation is a function of many factors including proximity to onshore infrastructure, water depth and seasonal operating restrictions.

Table 2.19. Estimate of ultimate production of oil and gas from the Beaufort Sea OCS area.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/07	0.00	0.00
ERR as of 12/31/07	0.00	0.00
Reserve growth in producing fields (12/31/07)	0.00	0.00
Near-term exploration success (2008 to 2018/2020)	0.65	1.00
Long-term exploration success (2018/2020 to 2050)	4.30	20.00
TOTALS	**4.95**	**21.00**

Chukchi Sea OCS Area: The Chukchi Sea OCS is an attractive exploration area and it will become an active and rewarding exploration province if key conditions are met. These include the development of an infrastructure within NPRA, the existence of both an oil and gas pipeline, and favorable price recovery for both commodities. It is possible that the lure of the gas resources, believed to be associated with the Burger feature (Craig, and Sherwood, 2005), will accelerate this pace somewhat. However, this is dependent upon a contractual obligation to build the gas pipeline from the North Slope to southern markets. However, it is also likely that any active exploration in the Chukchi Sea will depend on the measured westward expansion of infrastructure to western NPRA. **A lease sale was held in February 2008 and the high bid levels and large number of leases sold (Figure 2-5) indicate that exploration and follow-on activities may occur sooner than anticipated.**

Of the 22 plays identified by the MMS (Sherwood et al., 1998) four have the bulk of the aggregated mean risked undiscovered technically recoverable reserves (Sherwood et al., 1998). These plays and their mean risked undiscovered recoverable resources are the Endicott-Chukchi Platform (3.00 BBO and 9.76 TCF), Rift-Active Margin (4.14 BBO and 8.55 TCF), Rift-Stable Shelf (2.25 BBO and 7.19 TCF), and North Chukchi High/Sand Apron (1.47 BBO and 17.98 TCF). These total nearly 10.86 BBO or 70.0% of the 15.5 BBO of the 2000 MMS revised assessment (MMS, 2000) and 43.48 TCF or 72.2% of the 60.1 TCF estimated in the 2000 MMS revisions.

The Endicott-Chukchi Platform play is comprised of Late Devonian(?) to Mississippian sandstones deposited in marginal marine to fluvial environments in the Hanna Trough during an early rift- or fault-driven phase of subsidence (Sherwood et al., 1998). The play area ranges from 75 to over 150 miles offshore in the central and western portions of the Chukchi Sea. The equivalent rocks are productive at the Endicott field in the Colville-Canning area. This play was not tested by any of the five wells drilled in the Chukchi Sea.

The Rift-Active Margin play consists of Late Jurassic to Early Cretaceous sandstones that were deposited in a zone of active faulting and flexural subsidence near an active rift margin (Sherwood et al., 1998). The faulting resulted in locally thickened intervals reminiscent of the Point McIntyre field. The strata are age equivalent to the Late Jurassic Alpine, Nuiqsut, and Nechelik sandstones and the Early Cretaceous Kuparuk River Formation. The area of prospectivity lies between 75 and 175 miles offshore in the northwest-central portion of the Chukchi Sea. In the Colville-Canning area, these units produce in the Alpine, Kuparuk, and Point McIntyre fields among others. Three wells (Burger, Crackerjack, and Popcorn) penetrated this play. The Burger and Popcorn wells encountered gas with condensate. The Burger structure has been estimated to contain risked mean resources of 9.48 TCF and 489 MMBO NGLs (Craig and Sherwood, 2005). **The Burger structure and several others, probed by the drill in the early 1990s, were re-leased in 2008 (Figure 2-4** and **Figure 2-5).**

The North Chukchi High/Sand Apron play is inferred to consist of shallow marine to fluvial sandstones of Early Cretaceous to Tertiary age and includes both Lower and Upper Brookian successions (Sherwood et al., 1998). There have been no discoveries in these rocks but time equivalent units in the Colville-Canning area include portions of the Sagavanirktok and Nanushuk Formations. This play area is in the central northern Chukchi shelf, between 90 and 170 miles northwest of Point Franklin. None of the five Chukchi Sea wells encountered this play.

Secondary plays, with mean risked recoverable resources between 0.5 and 1.0 BBO and 2.5 to 5.0 TCF are the Sadlerochit-Chukchi Platform (0.54 BBO and 2.99 TCF), Sadlerochit-Arctic Platform (1.16 BBO and 3.33 TCF), Lower Brookian Foldbelt (4.49 TCF), and Upper Brookian Paleovalleys (0.89 BBO). These plays total 2.59 BBO, 16.7% of the assessment area mean and 10.81 TCF, 18% of the aggregated mean.

The two Sadlerochit plays are targeting the same sequence of strata that are the primary reservoirs at the Prudhoe Bay and Northstar oil fields. The Sadlerochit of the Chukchi Platform consists of shallow marine fine-grained sandstones which were encountered by the Crackerjack and Klondike wells. Both of these wells established the presence of pooled hydrocarbons in the play sequence (Sherwood et al., 1998). The Sadlerochit-Chukchi Platform play area is 70 to 140 miles west to northwest of Icy Cape.

The Arctic Platform Sadlerochit sequence is thought to consist of marginal to shallow marine facies. The Diamond well penetrated this interval and found no hydrocarbons. However, the well encountered 310 ft of Ivishak sandstone and 575 ft of Echooka sandstone (the thickest observed anywhere). The play area extends from just offshore NPRA to about 140 miles northwest of Wainwright (**Figure 2-4**).

The Upper Brookian-Paleovalley play is inferred to be comprised of fluvial sandstones of Early Tertiary age. These rocks are thought to be time-equivalents of the Ugnu and portions of the Sagavanirktok Formation which produces at West Sak. The paleovalleys are located in the central portion of the western half of the Chukchi shelf and lie between 65 and 165 miles northwest of Icy Cape. Three wells, the Popcorn, Crackerjack, and Klondike, tested this interval and found thick sections of highly porous sandstone but no pooled hydrocarbons.

The Lower Brookian Foldbelt play is comprised of folded and faulted anticlines developed in the largely deltaic sandstone of the Nanushuk Formation. The foldbelt is located in the southern portion of the Chukchi Sea and just north of the Herald Arch. It extends from the coast line to nearly the Russian portion of the basin. This play was not tested by any of the Chukchi Sea exploration drilling. Onshore exploration drilling, primarily within NPRA, has resulted in the discovery of six gas fields (Tungak Creek(?), Wolf Creek, Gubik, Meade, Square Lake, and East Umiat).

The aggregated mean of the seven most prospective oil plays is 13.45 BBO or 86.6% of the estimated aggregated mean for the basin. Based on this assessment, virtually all future oil exploration will be focused on these intervals. Similarly the seven gas plays with the greatest resource potential are estimated to have 54.29 TCF or 90.2% of the aggregated mean for the Chukchi shelf assessment area.

The highly successful Chukchi Sea lease sale held in early 2008 could lead to exploration drilling as soon as 2010, but drilling in 2011 is more likely. The area is extremely attractive and possesses all the necessary components for a prolific petroleum province. However, the remoteness and the potential dependency on the westward spread of exploration within NPRA, and the accompanying development of the required infrastructure, may exert significant control over the timing of future activities, unless a discovery of sufficient size within the Chuckchi Sea area eliminates the necessity to depend on a preexisting infrastructure and pipeline system connecting to the Prudhoe Bay area and associated TAPS/North Slope gas sales system.

Based on the original assumption that a North Slope gas sales system would have been completed prior to the development of any Chukchi Sea discoveries and that an existing infrastructure extending into western NPRA would be required for Chuckchi Sea development, oil and gas exploration in the Chuckchi Sea area will probably proceed jointly with NPRA exploration and development activities. For this discussion approximately 60% of the aggregated mean oil and 75% of the aggregated mean gas assessments are assumed to be discovered by 2050 or about 9.5 BBO and 45 TCF. The higher proportion of the gas resource assumed to be discovered is based on the evaluation of the gas resource at the Burger prospect, where the MMS has calculated a risked mean resource of 9.48 TCF. The Burger prospect gas is reservoired within the Kuparuk River Formation equivalents of the Rift-Active Margin play. For the most likely case, the risked mean gas resource at Burger (9.48 TCF) is greater than the 1995 risked mean gas endowment (8.55 TCF) for the **entire** play that contains the Burger pool. Indeed the risked mean gas resource at Burger represents 15.8% of the year 2000 Chukchi-wide risked mean gas endowment of 60.11 TCF (Table 2.16). The risked mean condensate resource at Burger (489 MMBC) represents over 11% of the 1995 risked mean oil endowment for the Burger-type plays basinwide.

In structures with 100% oil, in the most likely case the upper limit of mean pool size may range above 1.0 BBO (Sherwood et al., 1998) and probably to as much as 1.5 BBO. The mean pools sizes in the most likely case for gas-only features were estimated by Sherwood et al., (1998) to range to nearly 9.5 TCF and may exceed 11.5 TCF. Primary oil prospects are considered to range between 0.5 and 1.5 BBO and secondary features to have between 0.25 and 0.5 BBO. The primary gas prospects are given a range of 5.0 to 10.0+ TCF and the secondary targets range from 2.5 to 5.0 TCF. There are thought to be 8 to 12 primary oil prospects and 4 to 6 primary gas prospects. The number of secondary oil and gas prospects are estimated to total about 20 and 12, respectively.

Considering that Burger is assessed to have between 9.5 and 14.0 TCF and nearly 500 MMBC the remaining risked undiscovered economically recoverable resources expected to be found by 2050 are 36.5 TCF and 9.0 BBO. Oil exploration is expected to result in five to seven large fields that range between 0.5 and 1.5 BBO and average approximately 1.0 BBO and yield 6.0 BBO. The discovery of approximately the same number of secondary prospects with an average of 350 MMBO would add an additional 2.1 BBO. The largest accumulations are expected to be found in the two Rift plays (Kuparuk equivalents), the Endicott plays of the Chukchi Platform, and Sadlerochit plays. Eight to 10 smaller satellite plays with 50 to 150 BBO may be expected to contribute an additional 0.9 BBO. Including the condensate at Burger, the total long-term additions of economically recoverable oil are approximately 9.5 BBO.

The gas potential may be higher than expected, if the revised estimate for Burger (Craig and Sherwood, 2005) is of the right order of magnitude. The most prospective gas plays are the Rift plays, the Brookian Sand Apron, and the Endicott-Chukchi Platform. With the Rift-Active Margin play having contributed a possible 9.5 TCF at Burger, it is probable that other large accumulations are present. Sherwood et al., (1998) suggest that the Sand Apron play has the greatest gas potential and may yield a 10.0+ TCF accumulation. The operating assumption is that an additional three fields in the 5.0 to 10.0+ TCF range will be found and average about 6.5 TCF. Five to six secondary gas accumulations are estimated to average 3.0 TCF. The total of primary and secondary discoveries, including Burger, is projected to be approximately 46 TCF. Smaller gas accumulations in the 1.0 to 2.0 TCF range may add an additional 4.0 TCF. The total long-term gas additions, including Burger, are expected to be in the area of 50.0 TCF.

Table 2.20 is a brief summary of the estimates of economically recoverable oil and gas expected to be discovered between 2007 and 2050. These numbers include the MMS

(Craig and Sherwood, 2005) estimates for the Burger discovery. **With the results of the 2008 lease sale there may be exploration success and production in the near-term, prior to 2018.**

Table 2.20. Estimate of ultimate recoverable oil and gas from the Chukchi Sea area.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/07	0.00	0.00
ERR as of 12/31/07	0.00	0.00
Reserve growth in producing fields (12/31/07)	0.00	0.00
Near-term exploration success (2008 to 2018/2020)	0.00	0.00
Long-term exploration success (2018/2020 to 2050)	9.50	50.00
TOTAL	**9.50**	**50.00**

Because of the remoteness of the Chukchi Sea plays from the existing infrastructure and any future gas pipeline from the North Slope to a southern terminus, there will be a long lead time from the establishment of commercial quantity of reserves to first production and transportation of oil or gas. It is estimated that 10 to 12 years may be required. **This timeline may be abbreviated by two to four years if a portion of the necessary infrastructure is extended into western NPRA prior to the development of the Chukchi Sea resources; or if discoveries are large enough to support stand-alone facilities in the Chuckchi Sea province.**

2.4.2.2 Other Federal Lands

By **2018/2020**, both exploration and development in the NPRA should be well established with activity proceeding westward and southward with the dual objectives of oil and gas. To the east, in the 1002 Area of ANWR either the area remains closed to drilling or exploration has begun, and, with early success, production of the first oil (gas?) will occur approximately two to three years into the future (in 2017 or 2018).

2.4.2.2.1 National Petroleum Reserve Alaska (NPRA)

The potential for medium-sized (by North Slope standards) oil and gas fields is good to excellent in NPRA. The northern portion of the area has numerous opportunities for Beaufortian Topset and to a lesser extent Brookian Clinoform oil accumulations. To the south the area is dominantly gas-prone with the best opportunities in the structural plays involving Brookian Topset and Clinoform units. Smaller accumulations are believed to be present in the Beaufortian Topset plays. Over the long term, the oil exploration program will gradually expand westward, following the Alpine-Nuiqsut-Nechelik trends. Some exploration programs may de designed to look for oil to the south, lured by the known accumulation in the Brookian Topset sequences at Umiat and the Brookian Clinoform potential.

The most promising oil play is the Upper Jurassic Topset play of the northeastern portion of NPRA, followed by the similar play in the northwest portion of NPRA and the Brookian Clinoform plays of the northern and central areas (Bird and Houseknecht, 2002). USGS reports (Houseknecht, 2003 and 2003b) indicate that there is the potential for one field with 0.5 to 1.0 BBO and an additional eight to nine fields with 0.25 to 0.5 BBO. Twenty to 30 fields with 50 to 250 MMBO are possible. An estimated 65 to 70% of these prospects lie within 25 to

100 miles of the Alpine field and its existing infrastructure and 75 to 80% of the oil is thought to be in Alpine-like plays.

Approximately two-thirds of the technically recoverable oil (6.5 BBO) is assumed to be found during the near- and long-term exploration process and ultimately produced economically. For the long-term success, the maximum field size is assumed to be 0.75 BBO with six fields in the 250 to 500 MMBO range and averaging 400 MMBO. An additional 15 fields in the 50 to 250 MMBO range and averaging 150 MMBO are considered to be economic because of proximity to the larger fields and the existing infrastructure. Five of the seven largest fields are expected to be within 100 miles of the Alpine field, as well as the majority of the smaller fields. The more remote discoveries may be as much as 200 miles west of Alpine and would most probably require a string of successes across the NPRA or a very large discovery in the Chukchi Sea to be viable.

The total quantity of economically recoverable oil expected to be discovered in this phase of exploration and development in the NPRA is estimated to be 5.4 BBO.

The prospects for gas are considered to be the best in the southern portion of the NPRA (Bird and Houseknecht, 2002). The assessments by the USGS (Houseknecht, 2003 and 2003b; Potter and Moore, 2003) suggest that there are numerous prospects with reserves in the 1.0 to 6.0 TCF range. The most prospective structural plays involve the Torok and the topsets of the Brookian. These two plays are assessed to have aggregated mean technically recoverable undiscovered resources of 28.5 TCF. The Upper Jurassic Topset and the Brookian Clinoform plays are thought to be attractive secondary gas targets. The four stratigraphic plays have an aggregated mean of 19.5 TCF. Based on recent drilling activity in Upper Jurassic Topset prospects of the northeastern portion of the NPRA, these rocks may also have considerable gas potential. Providing that the gas pipeline is approved and built in the timeframe suggested in this report, gas exploration will be a major component of exploration in NPRA by 2015.

The Torok and Brookian Topset structural plays are stacked plays, with the Brookian Topset plays (Nanushuk) atop the Torok Clinoform/Turbidite plays, and trend east-west across NPRA in a zone that is bracketed between 69º and 70º north latitude (Bird and Houseknecht, 2002: Figures 9 and 10). The Brookian Topset structural plays are represented by the Umiat oil field and the Gubic gas field. The East Kurupa gas field is an example of a Torok structural play.

These structural plays will probably be the first pure gas-oriented exploration targets, and it is assumed that as much as 75% of the 28.5 TCF will be discovered and proven to be economic. Estimates by the USGS suggest that 75 to nearly 85% of the technically recoverable resources may be economic, for gas cases in which gas prices range from $6.00 to $10.00/MCF (PN, 2006b). The first discovery is anticipated to occur between 2010 and 2012 with lead time to production of about seven years. The majority of the large structural plays will be discovered over a 15- to 20-year period. For modeling purposes the larger discoveries are considered to range from 1.5 to 6.0 TCF with one at 6.0 TCF and three ranging from 1.5 to 3.0 TCF and averaging 2.25 TCF. Six smaller discoveries ranging between 0.75 and 1.5 TCF and averaging 1.25 TCF are considered to be satellites to the large fields and will largely be discovered and/or developed post-2030. The anticipated additions of economically recoverable gas, from the structural plays, are approximately 20.25 TCF. These prospects are from 50 to 200 miles west and southwest from Alpine.

The stratigraphic plays are expected to have fewer resources and to be smaller individual accumulations. They will tend to be targets once the larger structural plays have been discovered and developed. Because the individual accumulations are thought to be relatively small, generally less than 1.5 to 2.0 TCF, the presumption is that not as many will be found and only those relatively close to the infrastructure will be developed. Thus, only about 50% of the technically recoverable resources attributed to these plays are projected to be developed. This value is expected to include associated gas from the Beaufortian Topset plays in the northeast and northwest which appear to have been considered to be gas deficient. The prospects with the best chance to be commercial have potential reserves in the 0.75 to 1.7 TCF range and average 1.25 TCF. Seven or eight such accumulations are estimated to be found. Possible reserve additions range from approximately 9.0 to 10.0 TCF. Much like the structural plays, most of these prospects are between 69º and 70º to 70.5º north latitude and are from 25 to 200 miles from Alpine.

With this level of success, the long-term exploration and development activities in NPRA will result in the addition of 30.0 TCF of economically recoverable gas. The summary of expected economically recoverable oil and gas, related to exploration activities is presented in **Table 2.21.**

Table 2.21. Estimate of ultimate recoverable oil and gas from the National Petroleum Reserve Alaska (NPRA).

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/07	0.00	0.00
ERR as of 12/31/07	0.00	0.00
Reserves growth in producing fields (12/31/07)	0.00	0.00
Near-term exploration success (2008-2018/2020)	1.10	1.00
Long-term exploration success (2018/2020-2050)	5.40	30.00
TOTAL	**6.50**	**31.00**

2.4.2.2.2 1002 Area of Arctic National Wildlife Refuge (ANWR)

The probability that the 1002 Area of ANWR will be opened to exploration and development is less than 50% but it is necessary to present a development scenario for the area that allows all contingencies to be considered and evaluated. In the near-term section (Section 2.4.1), the timing assumed for the exploration and development was such that the earliest discovery occurred in 2015–2016 and production did not commence until 2022. **Thus no production was attributed to any exploration success that may have taken place between 2008 and 2018/2020 and the bulk of any 1002 Area exploration and development and all production are anticipated to take place between 2018/2020 and 2050.**

A summary of the results of the 1998 assessment (Bird and Houseknecht, 1998, Table 2.12) is presented in **Table 2.22**. As seen earlier, these estimates are considerably larger than those of previous assessments, and the areal and play distribution of the technically recoverable resources, of the 1998 assessment (Bird and Houseknecht, 1998) are markedly different from those of the 1987 USGS assessment (Dolton et al., 1987). The range and mean of technically recoverable oil and nonassociated gas resources for the entire study area (**Table 2.22**) are 5.72 to 15.96 BBO with a mean of 10.32 BBO and 0.0 to 10.85 TCF with a mean of 3.84 TCF. The range and means for the 1002 Area, excluding the state shallow water and ASRC lands, are 4.25 to 11.8 BBO and 7.67 BBO. **The potential distribution of gas resources, by land/subsurface rights owner, was not included.** For this scenario the entire area is treated as a unit, since it is highly unlikely that the majority of the ASRC or state lands can be developed without the 1002 Area being open for exploration.

Table 2.22. Technically recoverable oil and nonassociated gas for 1002 Area of the Arctic National Wildlife Refuge (Source: Bird and Houseknecht, 1998).

Segment Assessed in 1998	Oil (BBO)			Nonassociated Gas (TCF)		
	95 %	Mean	5%	95 %	Mean	5%
Entire assessment area	5.72	10.32	15.96	0.0	3.84	10.85
ANWR 1002 Area (federal) Total	4.25	7.67	11.8	0.0	????	????
Undeformed part of federal lands	3.40	6.42	10.22	0.0	0.47	????
Deformed part of federal lands	0.0	1.25	3.19	0.0	3.37	????

The 1998 assessment (ANWR Assessment Team, 1999) identified 10 plays. These can be considered to consist of two areally distinct groupings with little if any overlap. The first group of six plays is largely stratigraphic in nature with some large but relatively rare structural traps. These plays are present northwest of the Marsh Creek Anticline trend in the "undeformed" portion of the 1002 Area. The remaining four plays lie in the deformed portion of the 1002 Area, east and southeast of the Marsh Creek Anticline. These plays are mainly structural in character and require four-way dip closure or up-dip sealing faults.

The six plays of the undeformed area are: (1) Brookian Topset of the Paleocene to Miocene Sagavanirktok Formation, (2) Brookian Turbidite in the Paleocene to Oligocene Canning Formation, (3) Brookian Wedge of the Eocene Sagavanirktok/Canning Formations, (4) and (5) Beaufortian Topset in the Early Cretaceous Thomson and Kemik Sandstones, and (6) undeformed Franklinian of the pre-Mississippian carbonates and clastics.

The four plays of the deformed area are: (1) Deformed Franklinian in pre-Mississippian carbonates overlain by Brookian rocks, (2) Thin-Skinned Thrust-belt within the Brookian Sagavanirktok and Canning Formations, (3) Ellesmerian Thrust-Belt within Mississipian through Early Cretaceous strata, and (4) Niguanak-Aurora principally consisting of Franklinian strata with lesser contributions from overlying Beaufortian and Ellesmerian units.

Based on the 1998 assessment (Schuenemeyer, 1999), only three of these plays have mean technically recoverable resources in excess of 1.0 BBO and 1.0 TCF. These are the Brookian Topset (6.2 BBO and 1.7 TCF) and Brookian Turbidite (1.6 BBO and 1.6 TCF) plays of the undeformed area and the Thin-skinned Thrust-belt (1.15 BBO and 1.8 TCF) play of the deformed portion of the 1002 Area. The aggregated means for these three plays are 8.95 BBO and 5.1 TCF.

While these three plays would be the most obvious exploration objectives, based on the distribution of resources presented in the 1998 assessment, most of the less prospective plays could be secondary exploration targets due to the superposition of the various plays. The widespread distribution of the topset and turbidite plays are such that they overlay most if not all of the areas occupied by the four less prospective plays. Similarly, the Thin-Skinned Thrust-Belt play is locally underlain by the deformed Franklinian and Niguanak-Aurora plays, with the Deformed Franklinian play in the western and central portions of the Thin-Skinned Thrust-Belt play and the Niguanak-Aurora play in the eastern portion. The Ellesmerian Thrust-Belt play barely overlaps these plays in the southern portions of their distributions and would probably not be a stand-alone objective.

At the most probable time for development, the nearest infrastructure would be the facilities at Point Thomson and these would serve as the central gathering location for oil and/or gas produced within the 1002 Area, adjacent State waters, and ASRC inholdings. Thus, more than 50% of the potential reserves, as distributed in the 1998 assessment, would be within 35 miles of the Point Thomson production and transportation facilities. The most remote topset and turbidite accumulations would be approximately 60 miles from Point Thomson. The most distant Thin-Skinned Thrust-Belt prospects could be up to 90 miles east of Point Thomson.

With the assumption that 70% of these resources (8.95 BBO) are converted to economically recoverable reserves, the reserve additions would total 6.25 BBO and 3.5 TCF. With $51.00 per barrel oil prices the USGS estimates 90% of the technically recoverable oil would be economic (Attanasi, 2005). **Even though current oil prices are in the $40.00 per barrel range, oil prices are expected to recover as the world economy recovers. Thus it is reasonable to expect that economically recoverable reserves will be 70% or greater as assumed.**

The author believes that the volumes for the deformed area are conservative and that greater potential for both oil and nonassociated gas exists in the deformed portion of the 1002 Area than the 1998 USGS assessment indicates. The Angun Point and Manning Point oil seeps are well within the limits of the deformed zone and support the migration of oil into the area and the possible accumulation of Canning Formation (Mikkelsen Tongue) oils in reservoirs of this portion of the 1002 Area. **Similarly, the large Niguanak and Aurora structures are ideally situated to act as traps and reservoirs for gas generated in the deeply buried Ellesmerian and Beaufortian source rocks of the southern portions of the 1002 Area.**

The first exploration wells would probably have multiple targets and evaluate those intervals most easily identified and confirmed by seismic data. Thus, the topset structural plays and the thin-skinned thrust-belt prospects plus the more obvious stratigraphic turbidite plays would be likely early targets within the areas of overlap. The overlap zone of two plays within 30 to 40 miles of Point Thomson will probably see the first exploration drilling. With time, exploration drilling will proceed to the east and focus on the topset, turbidite, and thin-skinned thrust-belt play prospects with the other plays being secondary objectives.

The topset play has a variety of trapping styles including anticlines, growth anticlines, growth faults, up-dip shelf-edge pinch-outs, and stratigraphic lenses (Houseknecht and Schenk, 1999). The topset play, and to a slightly lesser extent the turbidite play, occupies the entire area of the undeformed portion of the 1002 Area and extends south-southeast from the Barter Island area into the central portion of the 1002 Area. The Turbidite play lacks this southward extension. Both plays generally trend parallel to the Beaufort Sea coastline in a belt that ranges from 10 to 20 miles wide (Houseknecht and Schenk, 1999 and 1999b).

Under the preferred scenario, the first economic discovery will be made in 2012/2013 and probably in Sagavanirktok Formation reservoirs (topset play), which have a mean technically recoverable resource estimated to be 6.3 BBO (Schuenemeyer, 1999). The first discovery is expected to be in the 0.5 to 1.0 BBO range (750 MMBO) and to be within 40 miles of Point Thomson. Reservoir properties will resemble those of the Kuvlum and **Sivulliq** fields for a potential Sagavanirktok reservoir. Additional topset discoveries are expected to be found, including another field of similar size, a field in the 1.0 to 1.5 BBO range (1.25 BBO) and three accumulations in the 0.25 to 0.5 BBO range (average of 0.35 BBO). Four fields in the 0.125 to 0.25 BBO (average 0.15 BBO) are anticipated to be discovered within 20 to 60 miles of Point Thomson. An unknown number of satellites (probably 6 to 10) are to be expected, with per field reserves in the 30 to 75 MMBO range, with an average of 50 MMBO). This level of success would yield 4.80 BBO from Brookian Topset prospects.

The near exact concordance of the turbidite and topset play areas would greatly facilitate the exploration of the Canning Formation turbidite play. The turbidite prospects may require 3D seismic data to be adequately defined. The most obvious features are mounds and channels (Houseknecht and Schenk, 1999b). Existing accumulations attributed to this play-type include the Badami, Flaxman Island accumulation, and possibly Sourdough.

Schuenemeyer (1999) estimated that the mean technically recoverable resources for this play are 1.6 BBO, with the largest accumulation in the 0.25 to 0.50 BBO range. Exploration success is anticipated to yield one field with 350 MMB of economically recoverable oil. This field is expected to be found in the 2013 to 2020 timeframe and to be within 50 miles of Point Thomson. Additional discoveries, between 2015 and 2035, are estimated to include three accumulations in the 125 to 250 MMBO range, probably averaging 175 MMBO and three to five smaller, satellites in the 50 to 100 MMBO range. The smaller fields must, out of economic necessity, be discovered in close proximity to larger, stand-alone fields of this or other plays in order to be developed. Aggregated additions from the turbidite play are approximately 1.2 BBO.

Perry et al. (1999) recognize the thin-skinned thrust-belt play as consisting of northeast-trending folds and thrust-bounded structures which formed in the Brookian succession above a detachment lying above and close to the pre-Mississippian basement. The play extends east-northeastward across the 1002 Area from the extreme southwest corner where it is only about 10 miles wide and widens to approximately 30 miles, encompassing the entire coastline from Barter Island to Aichilik River (Potter and Moore, 2003). This play is considered to have analogs at Umiat, East Umiat, and Gubic fields, in and near NPRA, and in the Beaufort Sea and Mackenzie Delta areas to the east in Canada.

The thin-skinned thrust-belt play is estimated to have mean recoverable resources of 1.15 BBO (Schuenemeyer, 1999). The potential for stand-alone economically successful accumulations for this play are limited. Schuenemeyer (1999) estimates that the largest field is in the play is in the 250 to 500 MMBO range with only one additional play in both the 125 to 250 MMBO and 62.5 to 125 MMBO ranges. Most of the accumulations are expected to be small and would probably contain less than 50 MMBO (Schuenemeyer, 1999). Presuming that one field is discovered in each of the class sizes and the smaller fields can take economic advantage of proximity to larger accumulations the economically recoverable oil attributable to this play would aggregate to 750 MMBO. It is likely that these discoveries would occur between 2015 and 2025. The assumption is that the larger fields would be discovered first and would tend to be associated with the Marsh Creek anticline and the southern margin of the Aichilik high.

Using the USGS 1998 estimate for mean technically recoverable resources attributable to the entire study area (**Table 2.22**) and, assuming 75% of the technically recoverable resources in the three most prospective plays, are converted to economically recoverable resources as discussed above, the 1002 Area would yield approximately 6.8 BBO, in good agreement the earlier estimate of 6.75 BBO.

The gas resource was not treated as an exploration objective in the 1998 study. The aggregated OGIP for all 10 plays is 18.5 TCF and the aggregated technically recoverable gas is 8.59 TCF with 3.84 TCF (47%) as nonassociated gas and the remaining 4.75 TCF as associated gas.

The technically recoverable associated gas is anticipated to be discovered as a by-product of oil exploration and is expected to be found in three plays, the Topset (1.7 TCF), Turbidite (1.4 TCF), and Thomson (0.46 TCF) plays. This comprises 75% of the associated gas. Two of these plays are the most prospective for oil and the gas and would be found early in the exploration process. The Thomson play would be a probable secondary objective in any exploration due to the reserves at Point Thomson. A total of approximately 2.0 TCF may be expected in association with the oil discoveries.

The most prospective nonassociated gas opportunities are within the deformed portion of the 1002 Area and are the Deformed Franklinian (0.82 TCF), Thin-Skinned Thrust-Belt (1.47 TCF), and Ellesmerian Thrust-Belt (0.88 TCF) plays. The data presented by the USGS (Bird and Houseknecht, 1998) does not support an extensive gas exploration effort in the 1002 Area. Thus, if the assessment data are utilized for purposes of forecasting gas reserve additions, the contribution from the 1002 Area will be minimal and not worth considering as a major factor in future production.

While the 1998 USGS assessment allocated the greatest reserves to the plays of the undeformed area, other investigators have attributed a greater proportion of the area's oil resources to the plays in the deformed portion of the 1002 Area. This was also true of the 1987 USGS assessment. Without going into detail regarding the decision to reallocate the majority of the area's resources to the undeformed portion of the 1002 Area, it remains possible that there may be a greater potential for oil and gas in the southeastern two-thirds of the 1002 Area than is reflected by the 1998 assessment. The major obstacle would appear to be charging the large Niguanak and Aurora features with oil and/or gas.

Grow at al. (1999) have approached these features with two scenarios – as a play with two large individual and unique prospects and as a play with many individual prospects. In the two-prospect case, the prospect closure is thought to range from 120,000 to 250,000 acres with a median of 180,000 acres. The range of trap depths is from 9,000 to 15,000 feet with a median depth of 12,000 feet. In the many-prospect scenario, the closures are considered to range from 5,000 to 120,000 acres with a median of 20,000 acres. With features of this size and the possibility of sourcing from the Hue Shale and Mikkelsen Tongue of the Canning Formation, it is difficult to believe that these features will not be high on a prospective lessee's drilling agenda. Whether the hydrocarbon charge is oil or gas, the potential for a very large accumulation exists. The proposed median trap fill for the many-prospect case is 45% and 20% for the two-prospect scenario. The 20% fill reflects the extreme size of the features and the low probability that the features could be filled or that a seal would be sufficient to retain the size of the hydrocarbon column required to fill the structures.

Table 2.23 has been constructed in the same manner as Table 2.18 to Table 2.21 and summarizes the expected economically recoverable oil and gas associated with exploration in the 1002 Area of ANWR, if the area is opened to oil and gas exploration and development.

The volumes associated with a more optimistic oil or gas case have not been calculated for this play, but if there was sufficient charge available, these features could have oil-in-place or gas-in-place volumes is the billions of barrels and trillions of cubic feet. With recovery factors of 25 to 30% or more, the ultimate recoverable oil resources from the 1002 Area could be increased by 50 to 100% and gas resources could be in the trillions of cubic feet.

Table 2.23. Estimate of ultimate recoverable oil and gas; 1002 Area of ANWR.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	0.00	0.00
ERR as of 12/31/04	0.00	0.00
Reserves growth in producing fields (12/31/04)	0.00	0.00
Near-term exploration success (2005 to 18)	0.00	0.00
Long-term exploration Success (2018 to 50)	6.75	2.00+
TOTAL	**6.75**	**2.00+**

2.4.3 Summary of Exploration Results

The undeveloped and, in many instances, unexplored prospective areas of the North Slope and adjacent Beaufort Sea and Chukchi Sea shelves have the potential to add billions of barrels of oil and trillions of cubic feet of gas to the shrinking volume of estimated remaining oil reserves and 35 TCF of known gas. These resources have the potential to support active exploration, development and production well into the middle of the 21st century. The estimated volumes of economically recoverable oil and gas presented in the preceding sections are predicated on the concept that the assessments by the MMS (OCS areas) and the USGS (onshore areas) are reasonable order-of-magnitude estimates. The timing, location, and play types associated with the postulated discoveries and the consequent development and production of these new fields are based on the assessed potential associated with the most attractive appearing prospects and their proximity to existing infrastructure.

Table 2.24 summarizes the discoveries by area and exploration phase. For the near term, all economically recoverable oil and gas additions are expected to be discovered or developed in the areas with active exploration operations at the time of this report (Colville-Canning, NPRA, and the shallow portions state and federal portions of the Beaufort Sea shelf). **The major emphasis for the near term will continue to be on oil exploration with the sole exception of gas-directed exploration in the Brooks Range foothills during the latter portion of the 2008 to 2018/2020 timeframe.** Near-term results are expected to be 2.85 BBO (perhaps an additional 0.5 to 0.8 BBO if Kuvlum and **Sivulliq** are more fully evaluated and developed) and 12.0 TCF (Table 2.24). There will be no commercial gas production **until 2018** or later.

The long-term discoveries largely reflect the expansion of exploration into those areas that have historically been excluded from exploration activities, are remote from existing infrastructure, and/or are gas-prone. The greater OCS areas of the Beaufort and Chukchi seas, the bulk of NPRA, and the entire 1002 Area of ANWR are representative of the first two areas of expanded exploration and the southern portions of both the Colville-Canning province and NPRA are typical of the gas-prone areas.

Additions of economically recoverable oil, as a result of long-term exploration success, are estimated to be more than 1.3 times the current EUR of producing and identified North Slope fields production of 21.06 BBO (Table 2.12) or about 28 BBO (Table 2.24). The Chukchi Sea, 1002 Area of ANWR, and the northern portion of NPRA are expected to contribute the greatest volumes of oil. These three areas alone are estimated to produce 21.65 BBO or a volume equivalent to the current EUR from known fields in the developed area of the Colville-Canning province and adjacent shallow waters of the Beaufort Sea (Table 2.6).

Table 2.24. Summary of forecast ANS economically recoverable oil and gas additions.

EXPLORATION PROVINCE	Near Term 2005 to 2015		Long Term 2015 to 2050		Total 2005 to 2050	
	Oil	Gas	Oil	Gas	Oil	Gas
Colville-Canning & State Beaufort Sea	1.1 BBO	10.0 TCF	2.05 BBO	23.3 TCF	3.15 BBO	33.3 TCF
Beaufort Sea OCS	0.65 BBO (plus Hammerhead and/or Kuvlum?)	1.0 TCF	4.3 BBO	20.0 TCF	4.95 BBO	21.0 TCF
Chukchi Sea OCS	N.A.	N.A.	9.5 BBO	50.0 TCF	9.5 BBO	50.0 TCF
NPRA	1.1 BBO	1.0 TCF (assoc. gas)	5.4 BBO	30.0 TCF	6.5 BBO	31.0 TCF
1002 ANWR	N.A.	N.A.	6.75 BBO	2.0+ TCF	6.75 BBO	??? (0 to several TCF)

TOTAL ARCTIC ALASKA	**2.85 BBO**	**12.0 TCF**	**28.0 BB0**	**125.3 TCF**	**30.85 BBO**	**137.3 TCF**

The majority of the economically recoverable gas additions are expected to be found and developed during the **2018/2020 to 2050** exploration phase (**Table 2.24**). Gas additions during this time interval are estimated to be in excess of 125 TCF with 100 TCF from the OCS and southern NPRA. **The cumulative gas additions are 3.5 times the known proven reserves as of January 1, 2008.**

These estimated additional volumes of oil and gas for the time interval from 2008 to 2050 are depicted by area in Figure 2-14.

Looking ahead to 2050, the additions to reserves through exploration are estimated to be approximately 30 BBO, or two times the current cumulative production, and 135 TCF, or about four times the current known gas reserves. This represents about 60% of the USGS mean estimate of undiscovered conventional gas resources for the North Slope, and adjacent OCS areas (PN, 2006b). These volumes do not take into account reserves growth within the existing fields nor the unconventional gas potential of CBNG or gas hydrates.

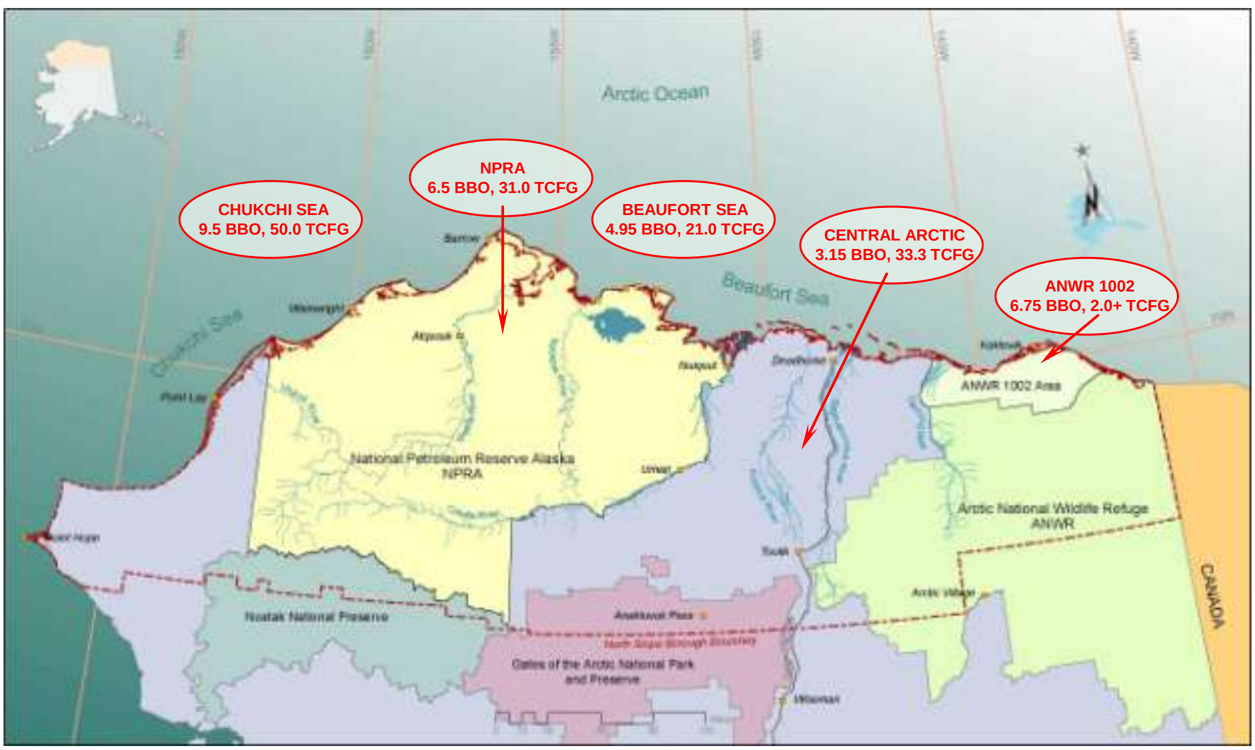

Figure 2-14. Estimated additions to Northern Alaska economically recoverable oil and gas resources from exploration during 2005 to 2050 interval.

(Current cumulative production, ERR, and reserves growth volumes are not included.)

2.5 Summation of Reserves and Economically Recoverable Additions

The ultimate magnitude of economically recoverable conventional oil and gas resources in Arctic Alaska includes the sum of the produced oil (and gas), the unproduced known reserves in the developed fields (Prudhoe Bay, Kuparuk, etc.), the known but undeveloped reserves (Point Thomson, Liberty, and others), volumes attributable to future reserve growth in producing fields (West Sak, Ugnu, and others), and the economically recoverable oil and gas anticipated to be added through future exploration and development. Most of these components of the ultimate potential for conventional oil and gas have been addressed elsewhere in this report and will be summarized again here and the component attributable to reserve growth will be reviewed and discussed.

2.5.1 Original Estimates of Ultimately Recoverable Reserves

Not all the discovered fields have published estimates of "reserves". The smaller oil fields, especially those within NPRA and gas fields, lack estimates of technically recoverable resources not to mention "economically recoverable reserves". Recently, there have been some efforts to provide these volumes. A notable example is the work of Verma et al. (2005) in which the authors assessed the Kavik gas field to have 165 BCF of in-place gas and technically recoverable resources of 115 BCF. The attempt to define EUR is limited by the values associated with the known producing fields. Any estimate of ultimate recovery for the other fields awaits commercial development, and consequently a total EUR for northern Alaska is a conservative number, even with respect to the known accumulations.

2.5.1.1 Producing Fields (as of December 31, 2007)

The original estimates of recoverable reserves for the producing fields are presented in Table 2.5. **These estimates total between 14.65 and 15.7 BBO and 30.575 TCF.** The range in estimated recoverable oil reserves is largely related to the uncertainty regarding recovery rates for the viscous oil fields in the Ugnu, West Sak, and Schrader Bluff accumulations. The recovery anticipated for these heavy oil accumulations is conservative and historically has been based on the use of older technologies. Recent technological advances have improved the rate and total recovery potential. The potential for reserve growth in these fields is very good and will be discussed later.

Several of the gas fields, included in the Table 2.5 tabulation, are being produced to supplement energy requirements for local villages. These fields would not normally be considered economic and would not have been developed except for the local needs. South Barrow, East Barrow, and Walakpa gas fields are in this category and had original reserve estimates totaling approximately 70 BCF, an insignificant portion of the gas reserve picture.

2.5.1.2 Discovered but Undeveloped Accumulations

Most of the discovered but undeveloped accumulations are presented in Table 2.6 as estimated technically recoverable resources and at this time are either uneconomic because of small size and/or remoteness (Umiat, Kavik, and Burger) or are awaiting the development of an appropriate infrastructure (Point Thomson). Some of the undeveloped fields that are expected to be developed within two to three years are included in Table 2.6. **The total estimated technically recoverable resources from the fields of Table 2.6 are 2.15+ BBO and 23 to 24+ TCF.** Many of these fields will be reevaluated based on current economics and technology and this may lead to eventual development over the next 5 to 20 years. **If it is assumed that approximately 75% of the technically recoverable resources will be converted to**

economically recoverable reserves, these fields will add 1.6 BBO and 17.2 to 18.0+ TCF to the reserve base.

In 2005, it appeared that the most probable conversions were Point Thomson, Kuvlum, Sivulliq, Liberty, Sourdough, Pete's Wicked, Oooguruk, Nikaitchuq, and Tuvaaq grouping of fields. Today Oooguruk is on production, Nikaitchuq will commence production in 2009, and Liberty is in the early development stage. Gubic and Umiat were thought to fit into this category as exploitation moves southward and the gas line is developed. Anadarko drilled at Gubic in 2008 and Renaissance is planning to drill at Umiat. Burger, in the Chukchi Sea, was thought to be at least 20 years (2025) from being commercialized, but with the results of the 2008 Chukchi Sea lease sale that timeline may be advanced by as much as 5 to 10 years (2015 to 2020).

2.5.2 Reserves Growth

Reserves growth may add significant quantities of oil or gas without any additional exploration. These reserves are usually "discovered" through better understanding of the reservoir geometry, redefinition of the reservoir, enhanced recovery technology, and improved economic conditions. Reserves growth will be addressed in the following sections; historic growth in existing fields (Section 2.5.2.1), future growth in producing fields (Section 2.5.2.2), and reserve growth anticipated during the producing life of yet undiscovered oil and gas fields (Section 2.5.2.3). Potential volumes of reserves associated with the third category are very nebulous and must be considered as speculative at best.

2.5.2.1 Discovery to Present (January 1, 2005)

Reserve growth has been demonstrated in most of the North Slope's major oil fields. Table 2.25 demonstrates the documented change in booked reserves on a field-by-field basis over the productive life of 10 of the fields in the Colville-Canning area. Note that the Lisburne and Badami fields are expected to produce significantly less oil than originally estimated. These fields differ in significant ways from the other oil fields presented in Table 2.25.

Table 2.25. Change in economically recoverable reserves (reserve growth) from discovery or onset of production to December 31, 2007 (EUR).

Producing Field	Original Reserve Estimate	Estimated Ultimate Recovery	Difference
Prudhoe Bay	9,590 MMBO	**14,066 MMBO**	**+4,476 MMBO (+46.7%)**
Lisburne	400 MMBO	**244 MMBO**	**-156 MMBO (-39.0%)**
Kuparuk River	600 MMBO	**3,090 MMBO**	**+2,490 MMBO (+415.0%)**
Milne Point-Kuparuk	110 MMBO	**413 MMBO**	**+303 MMBO (+275.0%)**
Endicott	375 MMBO	**599 MMBO**	**+224 MMB0 (+59.7%)**
Point Mcintyre	300 MMBO	**611 MMBO**	**+311 MMBO (+103.7%)**
Northstar	210 MMBO	**210 MMBO**	**0.0 MMBO (0.0%)**
Badami	120 MMBO	**60(?) MMBO**	**-60(?) MMBO (-50.0%)**
Tarn	42 MMBO	**160 MMBO**	**+118 MMBO (+280.9%)**
Alpine	430 MMBO	**564 MMBO**	**+134 MMBO (+31.2%)**
TOTAL	**12,177 MMBO**	**20,017 MMBO**	**+7,840 MMBO (+64.4%)**

The Lisburne oil field is the only producing carbonate reservoir on the North Slope. Despite porosity that may reach 20%, the reservoir has limited matrix permeability, about 0.1 to 0.2 million darcies (md) (Bird et al., 1987), and the production is largely controlled by fractures, which initially deliver oil to the borehole at high rates. However, the production has been shown to decline rapidly as the fractures are produced. The rate of delivery of oil to the fractures from the matrix porosity was historically so low that the well rates decreased by as much as 90% in a month. Recent implementation of extended reach horizontal wells and multilateral completions has markedly increased production and some of the apparent decrease in EUR may be regained. **Current expectations are that the Lisburne field will produce only 61% of the original EUR.**

In a somewhat similar situation, the Badami field was the first of several turbidite reservoirs to be developed, and the degree and extent of compartmentalization was not fully recognized at the time the field was developed. The efforts to restart the field involve the use of multilateral wells and recognition of the complex reservoir geology. There appears to be a good possibility of regaining some of the reserves thought to be lost due to the inability to meet reservoir performance standards. The shortfall is estimated to be 50% of the original EUR, but the potential for fewer reserves is great and the ultimate recovery may be considerably less than the estimated 60 MMBO.

In 2005, the Northstar field was viewed as having an EUR of about 6.7% less than originally estimated. The field was young, having only been producing since 2001 and it was antic ted that this field will also see an increase in the EUR over time. Currently, the field is thought to be able to meet the originally forecast EUR.

The majority of the fields have demonstrated significant reserve growth over their producing life (Table 2.25). **For these fields the reserves growth ranges from 31.0% at the Alpine field to 415% at the Kuparuk River field. The 10 fields, including the Lisburne and Badami fields, are expected to produce an additional 7,840 MMBO or 64.4% more oil than originally anticipated.** Thus, as many have said, "the best place to find oil is in an oil field".

2.5.2.2 Estimated Post-2004 Reserves Growth in Existing Fields

It is highly improbable that the EUR figures of Table 2.25 are the field abandonment values for production. While there is no expectation that fields such as Prudhoe Bay and Kuparuk River will continue to experience increases in reserves at the prior rates, they and other newer fields will be treated with more efficient tertiary recovery methods, such as CO_2 floods, and increase their yields beyond the currently forecast levels. In fact, new fields are now being brought on line with enhanced recovery technologies incorporated into the original development scheme. The availability of CO_2 in sufficient volumes may be attainable from the gas cap at Prudhoe Bay and from Point Thomson. There are an estimated 5.0 TCF of CO_2 in the Prudhoe Bay gas cap and oil column (Masterson, 2001), which is located in close proximity to the fields most able to benefit from such a program. Miscible CO_2 floods would be applicable to the majority of the producing fields and have the potential to increase recovery by 8 to 11% of the OOIP (Nelms and Burke, 2004).

The largest potential reserves growth will probably occur in the viscous, heavy oil fields. The current estimate of economically recoverable reserves is between 1.45 and 1.80 BBO (Table 2.5). The ultimate reserve numbers may be much larger and estimates cited by Rosen (2005) indicate that one-fifth of the ANS in-place viscous oil could be produced. Since the estimates for in-place viscous oil range from 26.0 to 45.0 BBO, the total recoverable reserves could be 5.0 to 9.0 BBO. The USGS (Anchorage Daily News, 2003) is quoted as estimating that the ANS has 7.0 billion barrels of recoverable heavy oil. New Technology Magazine (2005) and IHS Energy (2005), referencing the DOE, state that advanced enhanced recovery technology has the potential to extract "several billion barrels of oil".

The potential for reserves growth in the heavy oil fields is in the order of 3.0 to 4.0 BBO, and this oil can be expected to be produced between 2018 and 2050. The timing for the development and production of these volumes of heavy oil is dependent upon a favorable price structure, availability of technology, and a ready supply of reactant, perhaps CO_2 extracted from the gas as it is conditioned for the pipeline. If the full development of the heavy oil potential awaits a large and reliable supply of CO_2, it may be post-2018 before most of this potential is realized. The low gravity of these oils, generally between 14 and 21° API would dictate that only an immiscible CO_2 flood would be effective (Taber et al., 1996). Immiscible CO_2 floods are only about half as effective as miscible floods.

Presently, the operators are utilizing a number of technologies to increase the recovery in the producing areas and are planning to apply these elsewhere within the heavy oil zones. Among the technologies or procedures are (PN, 2007b):

- **extended reach horizontal wells**
- **multilateral wells**
- **water flood enhanced by lean gas injection**
- **sand handling techniques (heaters at the drill site and chemicals added to drop sand out)**
- **oil-based mud system**
- **electric submersible pumps with gas lift backup**

In the areas currently under development, these technologies are believed to have the potential to increase the recovery factor to 22% of the OOIP (PN, 2007b).

Fields currently on production may be expected to add reserves at rates dependent upon their age (prior growth), oil properties, and recovery technologies utilized. Fields such as Prudhoe Bay and Kuparuk River will see modest incremental growth and Alpine and Northstar more vigorous growth. Based on the performance of these reservoirs it may be possible to use them as analogs and estimate how newer fields such as Northstar may perform in terms of increased recovery rates and addition of reserves. An aggregated estimate of reserves growth for these 10 fields is 2.00 BBO with approximately two-thirds coming from Prudhoe Bay and Kuparuk River fields and the remainder from the smaller fields.

In summary, the potential for additional reserves growth from currently producing fields is 5.0 to 6.0 BBO (3.0 to 4.0 BBO from the viscous, heavy oil fields and 2.0 BBO from the conventional oil fields) with the great bulk of this **production post-2018**.

2.5.2.3 Potential Reserve Additions through Exploration

If exploration were to remain confined to the areas of current exploration and development activity (northern portion of Colville-Canning province and adjacent state waters, and eastern NPRA, refer to Figure 1-1), the magnitude of reserve additions would be significantly reduced from the projections made in the foregoing sections. A review of the contrast between the magnitude of potentially recoverable resources is provided by comparing the EUR of oil and gas if future activities were confined to the currently active areas and the EUR if all the provinces were systematically and thoroughly explored and subsequent economic discoveries were developed as proposed and outlined in the preceding sections (Table 2.26).

Table 2.26. Additions of economically recoverable oil and gas for differing exploration scenarios (including near and long term).

Area Under Development	Oil (BBO)			Gas (TCF)
	Growth	Exploration	Total	Exploration
Current Activity[a]	5.0-6.0	4.9	9.9-10.9	12.0
Current Plus NPRA & Southern Central Arctic	5.0-6.0	10.3	15.3-16.3	65.3
Current, NPRA, Southern Central Arctic, Plus Beaufort Sea	5.0-6.0	14.6	19.6-20.6	85.3
Current, NPRA, Southern Central Arctic, Beaufort Sea, Plus Chukchi Sea	5.0-6.0	24.1	29.1-30.1	135.3
Current, NPRA, Southern Central Arctic, Beaufort Sea, Chukchi Sea, Plus 1002 Area	5.0-6.0	30.35	35.35-36.35	137.3
a. Current Activity area – Northern portion of Colville-Canning province and adjacent state waters, and eastern NPRA – see Figure 1-2.				

2.5.2.3.1 2004 Core Producing Area

Under the unlikely circumstances that the areas of current exploration and development (core producing area) were to define the geographical limits of future activity in Arctic Alaska, the volume of additional oil and gas would consist of reserves growth in the existing fields and reserves associated with any new discoveries within this limited area. These are tabulated in the first row of Table 2.26 and indicate a total of 9.9 to 10.9 BBO and 12.0 TCF would be added by 2050.

Restriction of activity to this core area is highly unlikely. Exploration and development is even now moving westward within NPRA and this scenario does not include the possible delineation and potential development of the Sivulliq (Hammerhead) and Kuvlum oil fields.

2.5.2.3.2 Frontier Exploration

The addition of the four sub-provinces and the southern portions of the Colville-Canning area provide the reserve increases recorded in the second through fifth rows of Table 2.26. Economically recoverable oil, due to exploration, is estimated to increase from 4.9 BBO to 30.35 BBO as the frontier exploration provinces are explored and developed. The exploration derived additions to the economically recoverable gas base are even more dramatic, increasing from 12 TCF to 137.3 TCF. It is obvious from numbers such as these that for production to continue well into the middle of the 21st century and for the pipeline(s) to remain economically viable enterprises, there must be ongoing and widespread exploration and development of the regions conventional hydrocarbon resources.

While the probability is low that events will unfold as sequenced in the exploration and development scenario used for this evaluation, the general conceptual approach to exploration and the premise that larger fields will be developed and spur further drilling and subsequent development of accumulations otherwise uneconomic is sound. The projected number and size of discoveries are virtually all within the ranges proposed by the USGS and MMS assessment teams. The test of whether the primary fields will be sufficiently large to prove economic will be largely dependent on price and proximity to, or availability of infrastructure. The hydrocarbon generation potential for this large area, comprised of entire North Slope and the Beaufort and Chukchi Sea shelves, is at least 10.0 to 20.0 trillion barrels of oil and thousands of TCF of natural gas. Bird (1994) estimates that the Ellesmerian Petroleum System of the North Slope, generated 8.0 trillion barrels of oil. The additional generative potential of the Ellesmerian and other petroleum systems, not only on the North Slope but also beneath the offshore areas of the Beaufort and Chukchi Seas, should be sufficient to have generated hydrocarbon volumes of the magnitude suggested. Therefore, the additional economically recoverable resources attributed to future exploration success are a trivial fraction of the volumes generated.

2.6 Summary

The geological considerations discussed in this report support the conclusion that Arctic Alaska can have a long and fruitful future with respect to the development and marketing of the region's oil and gas resources provided: (1) favorable oil and gas prices recover, (2) stable fiscal policies remain in place, and (3) all areas are open for exploration and development. The productive life of the Alaska North Slope would be extended well beyond 2050 and could potentially result in the need to refurbish or restructure TAPS and add capacity to the gas pipeline. However, the future expectation for Arctic Alaska becomes increasingly pessimistic if the assumptions are not met as illustrated by the following scenarios:

- Scenario 1: If the ANWR 1002 Area is removed from consideration, the estimated economically recoverable oil is 29 to 30 billion barrels of oil and 135 trillion cubic feet of gas.
- Scenario 2: Scenario 1 plus removal of the Chukchi Sea OCS results in a further reduction to 19 to 20 billion barrels of oil and 85 trillion cubic feet of gas.
- Scenario 3: Scenario 2 plus removal of the Beaufort Sea OCS results in a reduction to 15 to 16 billion barrels of oil and 65 trillion cubic feet of gas.
- Scenario 4: Scenario 3 plus no gas pipeline reduces the estimate to 9 to 10 billion barrels of oil (any gas discovered will likely remain stranded).

The most likely scenario is some combination of these hypothetical scenarios. Opening of the 1002 Area of ANWR is highly problematic and the likely restrictions on seismic and drilling activity in the Chukchi OCS and Beaufort OCS areas and possible restrictions to available development areas in NPRA support the lower estimates.

3. Engineering Evaluation

This section presents an **engineering evaluation of the ANS** petroleum producing complex **and is limited to an update of the technically recoverable oil and gas resources. In the 2007 report (Thomas et al., 2007), an economic evaluation of each pool was performed using a series of price forecasts for oil and gas and the then state of Alaska production tax system which was based on a gross production tax system. In 2006, the state legislature passed the Petroleum Profits Tax (PPT) bill and in November 2007 the legislature passed the Alaska Clear and Equitable Share (ACES) production tax bill which replaced the previous tax basis. The state of Alaska Department of Revenue (ADOR) publishes an analysis of the tax revenues anticipated by the state in the Annual Fall and Spring Revenue Sources Book.[19] The current production tax system requires a detailed knowledge of the net profits of each lease owner and operator in order to reliably predict the tax status needed for an economic evaluation. The quality of data publically available at the current time is not sufficient to perform a reliable update of the economically recoverable oil and gas resources. For this reason, this analysis presents an estimate of the technically recoverable resources only and no attempt has been made to predict or update estimates of economically recoverable resources.**

Specific objectives of the analyses are to:

- Estimate future ANS **technically recoverable** oil and gas production from: (1) currently developed fields, (2) pools **under development** with announced and pending development plans, and (3) pools with recognized potential for development **that are under evaluation**.
- **Update the forecasts for natural gas off-take for transport through a major gas sales pipeline, assumed to be operational in 2018.**
- **Develop oil and gas forecasts for the undiscovered North Slope resources for the basins described in Section 2.**

A brief description of each pool and field is provided and production forecasts of estimated **remaining technically recoverable** oil and gas resources and ultimate recovery are presented for individual pools from production history, field performance observations, and analog reservoirs. **These estimates are presented as technical remaining recoverable (TRR) resources and technical ultimate recoverable (TUR) resources.[20] Generic production forecasts are developed for pools that may be discovered through future exploration. These results are combined into composite forecasts of future ANS oil and gas production.**

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[19] ADNR-Tax Division, Revenue Sources Book Fall 2007, http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?1202f

[20] Petroleum reserves can have several different meanings depending on source and application for the reserves information. A general definition of petroleum reserves is the volume of hydrocarbons reasonably expected to be produced in some future time period under current or planned operations. See Section 3.1.3. of the 2007 study.

A major issue facing Alaska and the industry is how long ANS production can be stabilized before entering another period of sustained decline? This depends on the potential for new discoveries, continued development of smaller satellite pools, development of the heavy viscous oil resources, increasing recovery from existing reservoirs, and the effect of major gas sales on the economic life of ANS oil and gas production.

A major limiting factor in the economic life of ANS oil production may be the lower throughput limit for operation of Trans Alaska Pipeline System (TAPS). The recently completed TAPS Pipeline Reconfiguration by Alyeska Pipeline Service Company (Alyeska) (2004) has resulted in a reduction from the original 10 pumping stations (PS) with pumping capability to four stations (PS 1, 3, 4, and 9) that must be on line for any flow rate because of the mountain ranges and the associated elevation changes between PS 1 and Valdez. Reconfiguration involved replacing natural gas pump drivers with electric motors and modern centrifugal pumps. Three driver packages are currently installed at PS 1, 3, 4, and 9 that support throughput up to 1.14 MMBOPD (Alyeska, **2006**). Placing additional pump skids at these pump stations and at PS 7 and 12 would provide capacity of 1.5 MMBOPD. Taking pumping units off-line down to one unit at each of the four required stations is expected to result in a lower continuous operating limit of **about 200,000 BOPD (State Appraisal Review Board, 2007)**. The crude oil mix determined by current and future crude oil characteristics from known and undiscovered ANS pools and temperature profiles achievable at the lower rates will impact the lower limit that can be maintained. TAPS tariffs will increase as the throughput decreases because of fixed costs (e.g., operating and maintenance) related to pipeline costs being allocated to fewer barrels of oil.

The timing and amount of technically recoverable oil from the ANS that would be lost because of the total production rate reaching the TAPS lower limit will be shown for the scenarios analyzed in this section.

3.1 Engineering Analysis

This section presents a brief overview discussion of North Slope development history and the approach and data used to develop TRR forecasts of oil and gas.

3.1.1 Development History

The discovery of the Prudhoe Bay field in January 1968 is significant not only for the size of the discovery, but also because it is the largest oil accumulation in North America. This discovery was of sufficient value to support the grass roots development of a petroleum infrastructure on the ANS. The total ANS still produces about **14%** of the U.S. domestic oil production **over** 30 years after startup of production in 1977. The continued application of advanced technology combined with the relentless effort to reduce costs has allowed this major oil production province to sustain a major role in the nation’s energy supplies. Advanced technology has allowed technical and economic access to an increasing fraction of the total petroleum endowment with decreasing physical impact.

The development of the Prudhoe Bay Unit (PBU) required the installation of a complete petroleum infrastructure prior to the delivery of oil to domestic markets, which occurred 10 years after discovery (Thomas et al., 1991). The construction of TAPS, the delivery of production facilities by sealift, drilling supplies, and crew quarters was a huge logistical undertaking. PBU production increased from 316 thousand barrels of oil per day (MBOPD) in 1977 to over 1,500 MBOPD by 1980. This rate was sustained though 1989. Peak production coincided with a higher oil price regime through 1985, providing large revenues to the stakeholders (industry; state, local, and federal governments). Industry reinvested a portion of these revenues to support the development of the Kuparuk River field and for continued exploration. First production from the Kuparuk River Unit (KRU) was in 1981 and production increased to a plateau of over 300 MBOPD by 1988 before starting on decline in 1992. KRU development was scheduled to allow full utilization of TAPS capacity consistent with the oil markets and the investment climate.

ANS oil production increased to **2,017** MBOPD in 1988 including production from the Lisburne and Endicott fields before starting to decline in 1989. This decline continued until 2000 when oil production was stabilized at **just under** 1,000 MBOPD from 2000 through 2003 **as a result of discovery of new pools, development of satellite accumulations, and application of advanced technology before declining to about 720 MBOPD in 2007 as shown ~~is~~ in Figure 3-1.**[21]

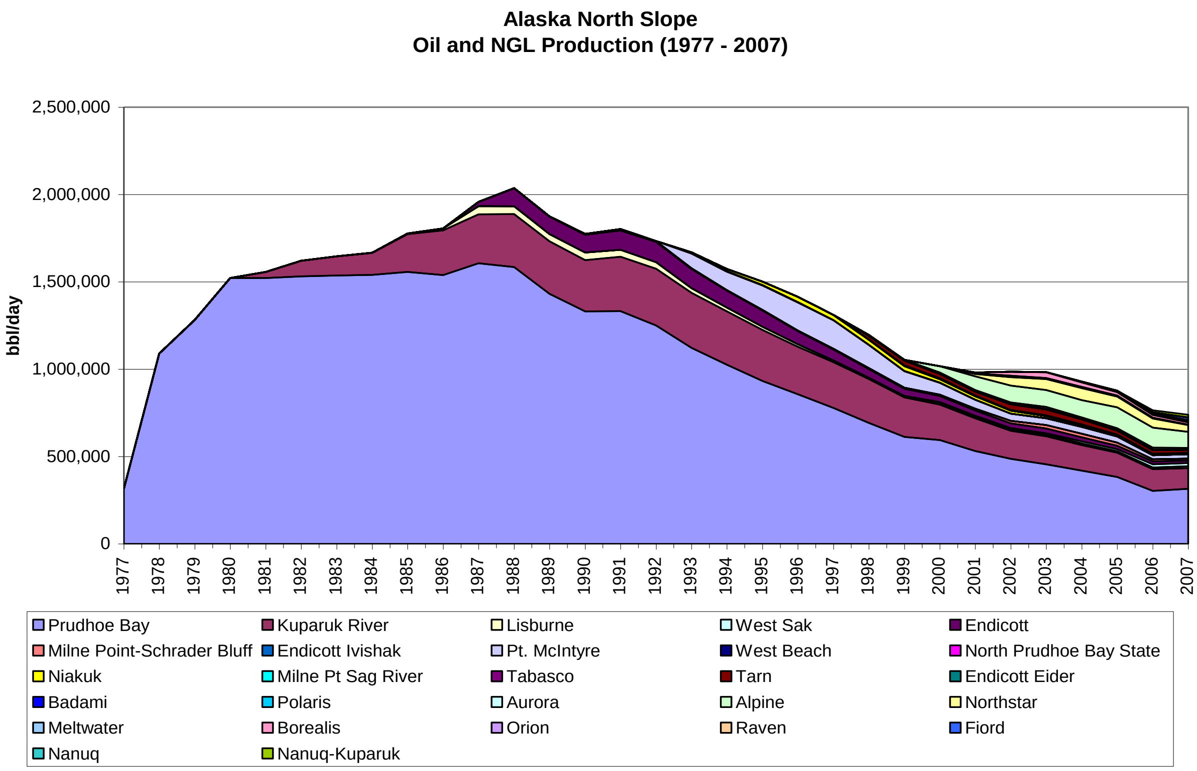

Figure 3-1. Alaska oil and NGL production history by pool (AOGCC, 2007).

Lower 48 oil production **declined from 9,408 MBOPD in 1970 to 4,314 MBOPD in 2005 and has increased to 4,384 MBOPD in 2007 as shown in Figure 3-2 (EIA-http://tonto.eia.doe.gov/dnav/pet/xls/pet_sum_snd_d_nus_mbbl_m_cur.xls#'Data 1'!A1.**

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[21] http://www.aogcc.alaska.gov/homeogc.shtml

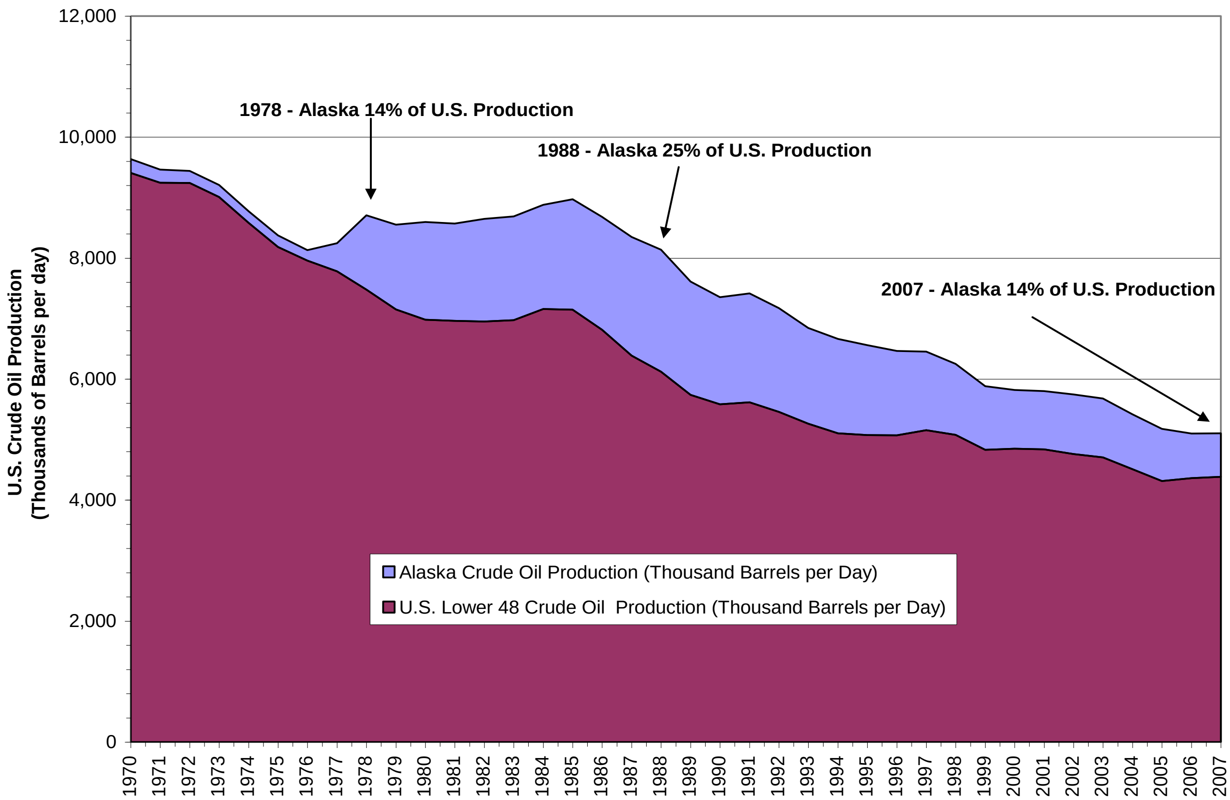

Figure 3-2. Comparison of Lower 48 and Alaska oil production history.

3.1.2 Data Sources

The TRR forecasts rely on publicly available information **from a variety of sources** including plans of development filed with the Alaska Department of Natural Resources (ADNR), conservation orders filed with the Alaska Oil and Gas Conservation Commission (AOGCC), open file information from both ADNR and AOGCC, and various trade publications. This information was also used in the preparation of production forecasts and development drilling scenarios.

The historic production data used in Section 3 were obtained from a data base maintained by the AOGCC. The AOGCC maintains a publicly available database of all production data from all producing pools in Alaska. This database consists of the production data for each pool; well name, date, oil, water, gas production, production days, water injection, gas injection, and water and gas injection days. The pool numbers assigned by AOGCC provide a unique identifier for each pool and are helpful as different accumulations are developed in the same formation and proximal to other pools in the same formation, unit, or both. The list of ANS pools **with current or past production, the** pool numbers assigned by the AOGCC, **and the cumulative liquid production reported by the AOGCC through December 31, 2007, are shown in Table 3.1 (Oooguruk Unit production began in 2008 and an Oooguruk Unit evaluation is included in this analysis for completeness). The original-oil-in-place (OOIP) volumes determined from**

the engineering evaluation of each pool are also shown in Table 3.1. The determination of the OOIP volumes is discussed in Section 3.1.5.

Prudhoe Bay OOIP is about **54%** of the total oil discovered on the North Slope to date **and accounts for about 73% of the total cumulative ANS production**. **As** shown in **Table 2.5**, the Ugnu accumulation, which is estimated to contain from 15 to 24 billion barrels of oil (BBO), is excluded from this evaluation as economically and technically infeasible for development at the present time. However, the Milne Point Unit Schrader Bluff pool as defined by the AOGCC contains productive zones in the Lower Ungu (Thomas et al., 1993, p B-4).

Table 3.1. AOGCC pool names, pool numbers, and cumulative production; and estimated original-oil-in-place (OOIP).

POOL NAME	AOGCC Pool Number	CUM. PROD. (MBO)	OOIP (MBO)
Colville River, Alpine Oil	120100	260,116	875,000
Colville River, Fiord Oil	**120120**	7,364	150,000
Colville River, Nanuq-Kuparuk Oil	**120185**	6,753	120,000
Colville River, Nanuq-Nanuq Oil	**120175**	162	30,000
Colville River, Quannik Oil	**120180**	55	79,000
Badami, Badami Oil	60100	5,198	300,000
Endicott[a], Endicott Oil	220100	466,240	1,059,000
Endicott, Ivishak Oil[b]	220150	8,178	18,000
Endicott, Eider Oil	220165	2,754	13,000
Kuparuk River, Kuparuk River Oil	490100	2,110,207	5,690,000
Kuparuk River, West Sak Oil[c]	490150	32,283	2,000,000
Kuparuk River, Meltwater Oil	490140	12,236	132,000
Kuparuk River, Tabasco Oil	490160	13,744	89,500
Kuparuk River, Tarn Oil	490165	86,019	525,000
Milne Point, Kuparuk River Oil	525100	206,386	850,000
Milne Point, Schrader Bluff Oil[c]	525140	53,304	2,000,000
Milne Point, Sag River Oil	525150	1,849	62,000
Milne Point, Ugnu Undefined Oil	525160	Not included	Not included
Northstar, Northstar Oil	590100	122,390	375,000
Prudhoe Bay, Aurora Oil	640120	22,124	165,000
Prudhoe Bay, Borealis Oil	640130	48,307	350,000
Prudhoe Bay, Lisburne Oil	640144	164,945	3,000,000
Prudhoe Bay, Niakuk Oil	640148	87,326	219,000
Prudhoe Bay, Prudhoe Oil	640150	11,510,197	25,000,000
Prudhoe Bay, Polaris	640160	6,543	430,000
Prudhoe Bay, Orion Schrader Bluff Oil	640135	11,359	1,070,000
Prudhoe Bay, Midnight Sun Oil	640158	16,612	60,000
Prudhoe Bay, Point McIntyre Oil	640180	413,934	1,120,000
Prudhoe Bay, North Prudhoe Bay Oil	**640152**	2,070	12,000
Prudhoe Bay, West Beach Oil	**640186**	3,582	15,000
Prudhoe Bay, Raven Oil	**640147**	1,641	14,000
Ooogaruk Unit, Oil[d]	**576000**	0[e]	265,000
Total		**15,683,878**	**46,087,500**

POOL NAME	AOGCC Pool Number	CUM. PROD. (MBO)	OOIP (MBO)

a. Endicott is known as the Duck Island Unit.
b. Sag Delta North PA is identified as the Ivishak Oil pool by the AOGCC.
c. The total OOIP for the West Sak and Schrader Bluff is described in **Table 2.5.**
d. Ooogaruk Kuparuk Oil and Nuiqsut Oil are combined as the Oogaruk Unit for this analysis.
e. Ooogaruk Unit production from the kuparuk and Nuiquist sands began in 2008.

3.1.3 Production Forecasts

For the engineering analysis presented in Section 3, a data cut-off of December 31, 2007, was used for the historic oil and gas production data. For the analysis, technical production is stopped at a level for each field and pool that is consistent with current cutting-edge technology as applied on the North Slope of Alaska.

A pool's TRR may be estimated from technical aspects considering alternative pool development, operational, and recovery technologies employed without specific consideration of price expectations and operating and development costs. One method used is an empirical production decline curve analysis where a production rate versus time plot is used to extrapolate a historic production trend into the future including the impact of known or expected modifications to recovery processes. In some instances where historical production data are not available, or not adequate for decline curve analysis, recoverable resources are geologically based, relying on volumetric quantities of oil and gas in place at the time of discovery and expected recovery factors from analogous reservoirs and fields. Hypothetical project developments use a standard production build up period, peak production plateau, and a decline production schedule, with the length of the plateau determined by the TRR.

Future water and gas production forecasts are determined **from the production history for producing fields. The Kuparuk River Unit Initial Participating Area (IPA) water cut and gas oil ratio (GOR) data and the extrapolations to abandonment are shown in Figure 3-3 to illustrate the methodology. In the case of fields that do not have adequate production history for development of forecasts, the data from a field with similar oil and reservoir characteristics (i.e.,an analogous field) are used to the develop the forecasts in the manner described in Section 3.2.1.8 of the 2007 report (Thomas et al., 2007). These water and gas forecasts are useful for the calculation of operating costs and for facility limitations. It should be noted that water production is related to the commercial recovery of oil and gas and is not the target of producable products, and that the forecasts of produced water are included as TRR and TUR for consistency only in this analysis.**

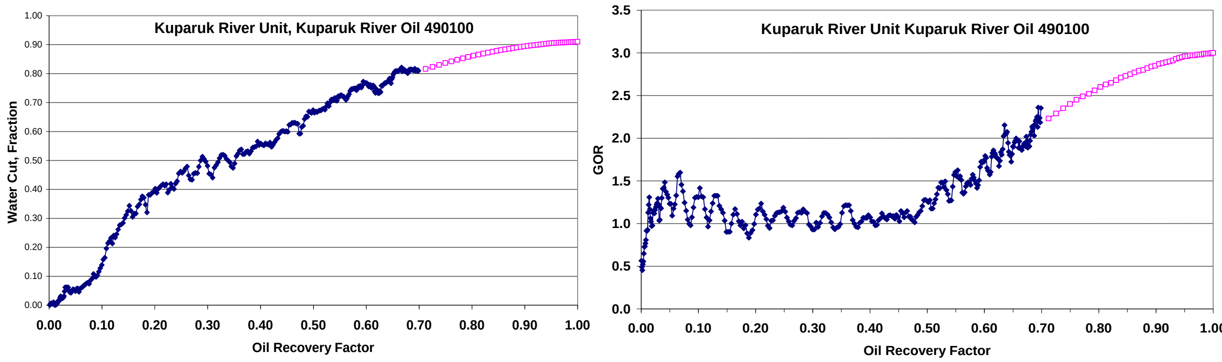

Figure 3-3. Kuparuk River Unit-Kuparuk pool water cut and GOR versus recovery factor.

3.1.4 Pool Data

Historical pool production is from the AOGCC electronic production database**, which is available at http://www.aogcc.alaska.gov/homeogc.shtml**. The database contains individual well records for monthly oil, gas and water production from April 1969. These production data are used for calculating derivative data such as active well counts, daily production, GOR, and water cut trends. Production data for producing pools are presented in **Section 3.2**.

3.1.5 Model Resource Parameters

Primary resource parameters are the OOIP, OGIP, oil gravity, the estimated total recovery (primary, secondary, and enhanced oil recovery (EOR))**, and recovery factor**. The recovery factor varies by field depending **on** the well spacing, improved oil recovery implemented, well configuration (vertical, horizontal, multilateral), and intrinsic reservoir and fluid properties. **The calculated recovery factor for a particular field depends on the recovery volumes and the estimated OOIP value used for that field. OOIP, OGIP, and recovery factor values available from or reported by various sources often (and usually) vary over a range of values depending on the information available to that source, and not all of the same information is available to all of the sources, thus not all reported values agree.**

The engineering evaluation for each pool presents an OOIP value (or range of OOIP values) obtained from a variety of sources including the AOGCC, ADNR, POD's, published public information, etc., if an available reference could be found; or, if an available reference could not be found, the OOIP value determined from the engineering analysis is presented. If the OOIP value was obtained from an available reference, then that source reference is cited. If the OOIP value was determined from the engineering analysis, then the OOIP value is indicated as "assumed". The same approach is used to present a recovery factor for each pool. These OOIPs and/or recovery factors were used as an initial guideline for the analysis, and adjusted, if necessary, as described below.

For the engineering analysis, historic production data (from the AOGCC data base) was plotted vs time and then extrapolated to an assumed production cut-off rate to determine the future TRR. The historic recovery to date was then added to the TRR to determine the TUR. The TUR was compared to the OOIP (selected from the various

sources available or determined separately in this analysis) to determine a calculated recovery factor. If the recovery factor was reasonable (for the type of reservoir and recovery methods used and/or planned) then the OOIP was considered acceptable. If the recovery factor was unreasonably high or low, the OOIP was adjusted up or down (within a reasonable range) to give an acceptable recovery factor. If the OOIP necessary to give an acceptable recovery factor was unreasonable based on the information available, then the field data was examined to determine if additional factors and/or production characteristics (i.e., reservoir size and continuity, effective drainage area, operational and development plans, recovery technologies, analogous reservoirs, production declne rate etc.) needed to be reconsidered. If after reconsideration, the results indicated a value that was different from other sources, then a best judgement (drawn from considerable experience in the oil industry and ANS activities) was used to select a value to present. Assumptions made regarding OOIP and OGIP values are indicated in this analysis.

Section 3 describes the methodology and values used for this report.

3.2 Producing Pools without Major Gas Sales

This section presents a description of the **engineering evaluations** for the currently producing pools and projects listed in Table 3.1. Production forecasts of estimated technically recoverable oil and NGLs are shown graphically for each pool. The **oil** production forecasts are tabulated in **Appendix A, Table A.1**.

The engineering evaluations and production forecasts for fields that are known but whose development is uncertain at this time are reported separately in Section 3.3 and the oil production forecasts are tabulated in Appendix A, Table A.2.

Section 3.2 is organized as follows:

Prudhoe Bay Field
- Prudhoe Bay Unit –
- Initial Participating Area (IPA)
  - Aurora Pool Participating Area (PA)
  - Borealis Pool PA
  - Midnight Sun PA
  - Orion PA
  - Polaris PA
  - Lisburne PA
  - Niakuk PA
  - North Prudhoe Bay PA
- West Beach PA
- Point McIntyre PA
- Raven PA

Duck Island Field
- Duck Island Unit
  - Endicott PA
  - Eider PA
  - Sag Delta North PA

Northstar Field
- Northstar Unit IPA

Badami Field
- Badami Unit IPA

Kuparuk River Field
- Kuparuk River Unit
  - Kuparuk River IPA
  - Meltwater PA
  - Tabasco PA
  - Tarn PA
  - West Sak PA

Milne Point Field
- Milne Point Unit
  - Kuparuk River IPA
  - Sag River PA
  - Schrader Bluff PA

Alpine Field
- Colville River Unit
  - Alpine IPA
  - Fiord PA
  - Nanuq PA
  - Nanuq – Kuparuk PA
  - Qannik PA

Oooguruk Field
- Oooguruk Unit IPA

3.2.1 Prudhoe Bay Unit IPA

The Prudhoe Bay pool was discovered in 1968 and produces 27.4º API crude oil from the Ivishak Formation (Table 2.5). The Ivishak Formation was unitized as the Prudhoe Bay Unit (PBU) and put into commercial production in June 1977. **Engineering analysis to determine TRR is** described in this section.

The Prudhoe Bay pool has an OOIP of 25 BBO and OGIP of 46 TCF[22] (Thomas et al., 1993 and 1996; ConocoPhillips, 2006)**, which includes crude oil, condensate, and NGLs**. **The total liquid** recovery from all technologies employed will be about **59%** of OOIP under **current operating practices**. The development of PBU involved the installation of a modern petroleum infrastructure in an Arctic wilderness and required significant resources of time, people, engineering, and money to develop. The installation of TAPS required federal legislation to proceed. PBU was initially separated into initial Oil Rim and Gas Cap participating areas (IPAs) with different ownerships and the Oil Rim IPA was separated into two different operating areas. BP Exploration (Alaska), Inc. (BPA) operated the western half of the Oil Rim IPA and ARCO

[22] The OGIP is about 46 TCF, which includes 12% CO_2 resulting in an OGIP for hydrocarbon gas of about 41 TCF.

Alaska operated the eastern half of the Oil Rim IPA and the Gas Cap IPA. In 2002, the two IPAs were combined and BPA became operator of the entire unit.

The developed area of PBU includes over 200 square miles. The IPA has six separate liquid and gas processing facilities. On the eastern side of the field they are called Flow Stations (FS1, FS2, and FS3) and on the western side of the field they are called Gathering Centers (GC1, GC2, and GC3). These facilities, field pipelines, and roads are shown in Figure 3-4 along with facilities at other North Slope Units. Although PBU has excess oil processing capacity, the facilities are currently at water and gas handling capacity.

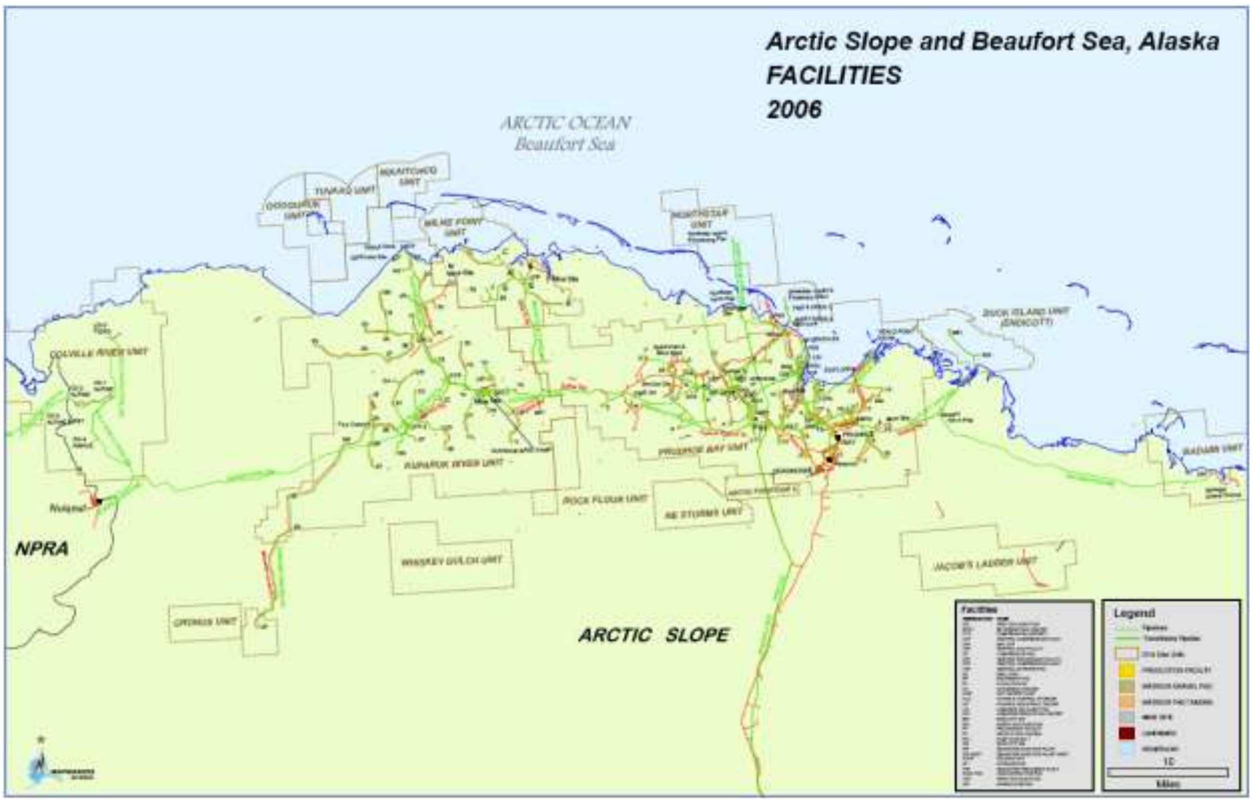

Figure 3-4. ANS Units, oil and gas processing facilities and pipelines.

By year-end 2007, about 1,100 wells had been drilled in **the PBU IPA**. From an initial rate of 137 MBOPD in June 1977, production quickly increased to over 1,000 MBOPD by March 1978. Production reached a maximum of 1,574 MBOPD in March 1980. The offtake rate for crude oil was limited by the state of Alaska to 1,500 MBOPD for conservation purposes. The PBU production volumes over 1,500 MBOPD were condensate and natural gas liquids (NGLs). Production averaged over 1,530 MBOPD for 106 months before the field started to decline in 1989.

The gas processing capacity was increased to 8.5 BCFPD in the early 1990s and led to a major expansion of miscible flooding for enhanced oil recovery (EOR). In addition, improved reservoir management, the application of multilateral wells from existing vertical wells, and other advanced production technologies have contributed to increasing the recovery factor **from**

about 38% (Table 2.25) to approximately 59% of the OOIP (25 BBO). It is assumed that these and other emerging technologies will continue to be applied in the future.

The historical **crude** oil plus condensate production is used to estimate future oil production **from the current development.** The historical **decline rate is becoming lower and is assumed for this analysis to be a result of the operating measures mentioned previously. It is further assumed these efforts will continue to be successful in the future. As a result the moderation of the decline rate is assumed to continue until production is ceased. Remaining technically recoverable resources are estimated from the December 31, 2007 production rate of 265 MBOPD to an abandonment rate of 80 MBOPD for an estimated TRR of 2,390.3 MMBO.**

The Prudhoe Bay Unit 2007 Plan of Development (POD)[23] for the IPAs listed some planned future projects that will increase recovery. These projects include drilling in the producing area, drilling in the peripheral area, well workovers, and expanding the use of EOR methods. It is assumed that a 15% increase in TRR will be obtained due to these additional projects, resulting in a recovery increase of about 360 MMBO which is assumed to be recovered over the remaining life to 2050. The first development is assumed to begin in 2008 with additional drilling. This results in an incremental TRR of 358.1 MMBO from these additional projects. The incremental impact of the additional oil production forecast is included in Figure 3-5.

[23] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

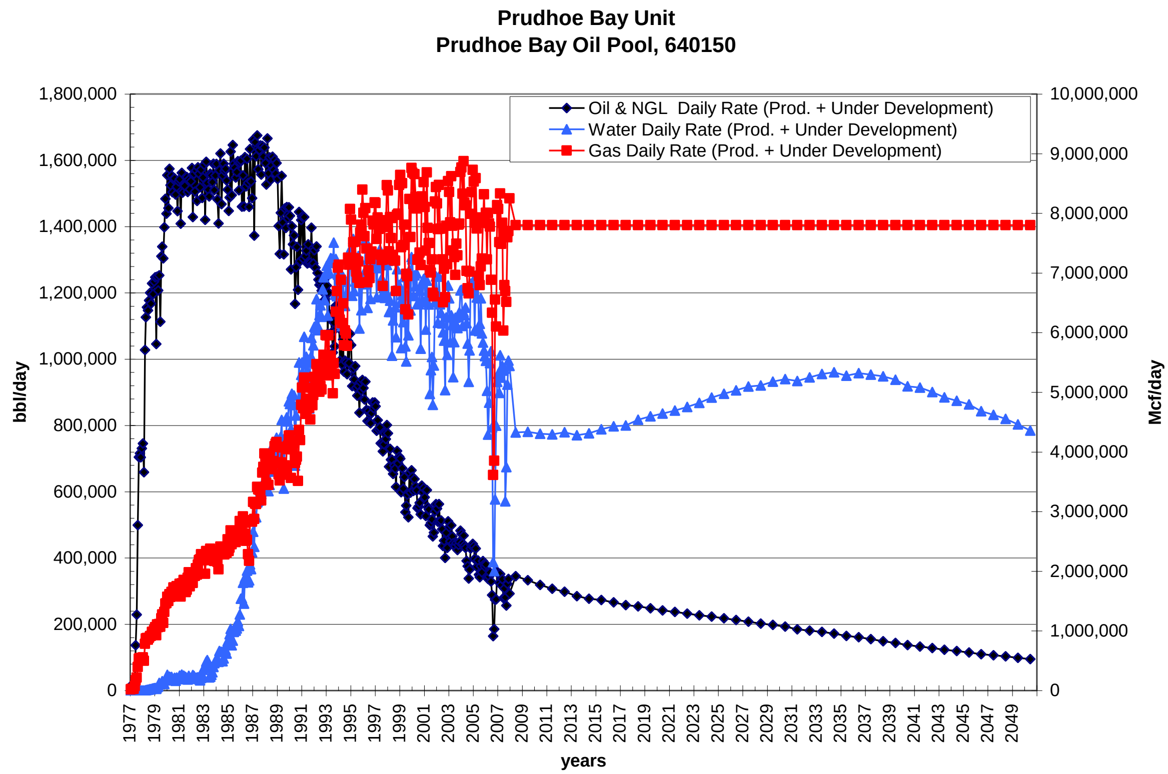

Figure 3-5. Prudhoe Bay Unit–Prudhoe Bay pool production history and forecasts.

Prudhoe Bay pool historical and future technically recoverable oil (crude oil, condensate, plus NGLs), gas, and water productions versus time are shown graphically in Figure 3-5.[24] The individual oil production forecast is tabulated in Appendix A, Table A.1.

The estimated recoverable resources from the projects under development, increases the PBU TRR estimate to 2,748.4 MMBO excluding NGLs. The TUR is 13,752.1 MMBO.

NGLs are currently recovered from produced gas, both solution gas and gas cap gas. The production of NGLs **from produced gas** is assumed to continue at the established decline of 5% per year **(without major gas sales)**. NGL recoverable resources are estimated from the current **60.0 MBPD to a final rate of 7.0 MBPD for a TRR for NGLs of 395,587 MB and a TUR of 902,121 MB.** The current gas production is controlled by the gas handling capacity of the PBU IPA facilities. The gas forecast is 7.8 BCFD with processed gas used for **MI** and lease operations. Excess gas, or about 92.5%, of the produced gas is currently reinjected into the gas cap and will continue until a gas pipeline is available to export natural gas from the ANS.

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[24] Put River/ARCO Prudhoe Bay State No. 1 production is reported with the Prudhoe Bay IPA production volumes and future recovery is included in the Prudhoe Bay IPA volumes (ADOG Annual Report, 2007).

Total TRR of oil, condensate, and NGLS is 3,143,987 MB and total TUR is 14,654,184 MB.

Gas production through 12/31/2007 totals about 56 TCF, which exceed current estimates of OGIP for the gas cap and oil rim. Future gas volumes are forecasted at the capacity of the processing facilities. Reinjected gas volumes are estimated using the information in the POD. The POD shows a combined 12.4% in the produced gas stream attributed to gas exports to other pools (1.1%), NGL shrinkage (0.9%), fuel usage (6%), flare volumes (0.2%), and miscible injectant production (4.2%). A factor of 87.5% is used to estimate future reinjected gas volumes.

Historical oil recovery versus water cut is used to estimate future water production with the response terminated at 0.9 water cut at depletion as **described in Section 3.1.3**.

Prudhoe Bay pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.2. Again, it should be noted that water production is related to the commercial recovery of oil and gas and is not the target of producable products, and that the forecasts of produced water are included as TRR and TUR for consistency only in this analysis.

Table 3.2. Prudhoe Bay Unit – Prudhoe Bay pool production statistics and forecasts as of 1/1/2008.

	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	11,003,663	2,748,400	13,752,063
NGL Production (MB)	506,534	395,587	902,121
Oil and NGLs (MB)	11,510,197	3,143,987	14,654,184
Gas Production (MMCF)	56,158,952	118,020,000	174,178,952
Gas Injection (est.) (MMCF)	51,081,658	103,267,500	154,349,158
Water Production (MB)	8,344,050	12,560,000[a]	20,904,050[a]
a. The forecasts of produced water are included as TRR and TUR for consistency only in this analysis.			

3.2.2 PBU – Aurora PA

The Aurora pool was discovered in 1969 and production from the Kuparuk Formation was started in December 2000 (Table 2.5). **Engineering analysis to determine** TRR is described in this section.

The Aurora pool is a recent satellite development targeting an accumulation of from **165 to 201 MMBO OOIP** of 29.6°API oil **(PN, 2003)**. The operator estimates primary recovery to be 12% of the OOIP and secondary recovery another 34%, for a TUR of 46% of the OOIP (AOGCC, 2001). **The production response (Figure 3.6) indicates the project is successful. Using the lower estimate of 165 MMBO OOIP and a TUR of 67,494 MBO (Table 3-3), the estimated recovery calculates to be about 41 % of OOIP.**

Oil production from the Aurora pool is being processed by the PBU IPA facility at the maximum rate possible under gas and water handling constraints. The pool started production November 2000, and by March 2003 achieved a production rate of about 10 MBOPD. Production **has averaged** above 10 MBOPD **through December 2007 and now appears to** be entering a decline.

Aurora pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-6. The historical oil production versus time plot was used to estimate the technically recoverable resources. The individual oil production forecast is tabulated in Appendix A, Table A.1.

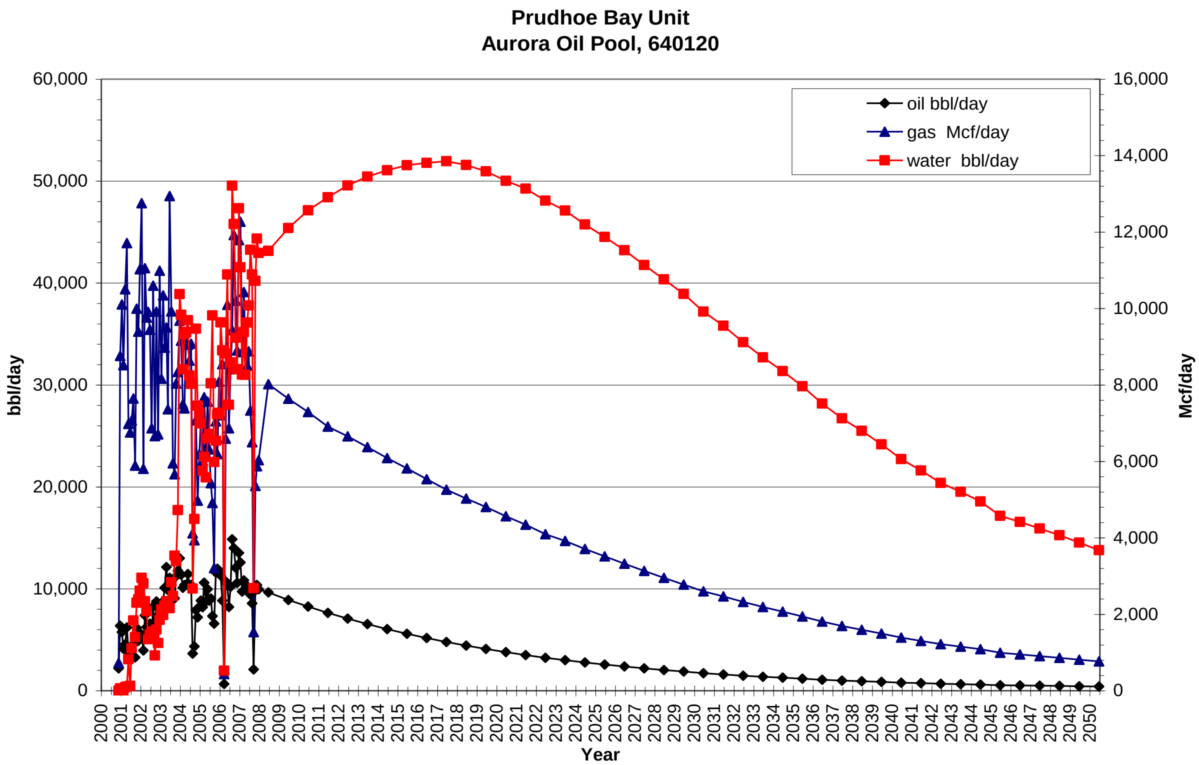

Figure 3-6. Prudhoe Bay Unit–Aurora pool production history and forecasts.

The waterflood was started in December 2001 and the miscible injection process in December 2003. It is assumed the combination of **drilling new wells,** waterflood, and the MI project **have maintained** oil production at approximately 10 MBOPD **since 2003.**[25] **Production reached a peak of about 14,000 MBOPD in 2006.**

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[25] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

The production forecast assumed **an average decline of about 7.5% per year**. The production forecast for the indicated **recovery** assumed a **production limit of 375 BOPD. This gives a TRR of 45,370 MBO, and a TUR of 67,494 MBO as shown in Table 3.3.**

The historical oil recovery versus **GOR** was used to forecast gas production. Historical oil recovery versus water cut was used to estimate future water production with the response terminated at a 0.90 water cut at depletion. Gas production in excess of lease operations is used in the MI project.

Aurora pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.3.**

Table 3.3. Aurora pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	22,124	45,370	67,494
NGLS	0	0	0
Gas Production (MMCF)	78,028	196,249	274,277
Gas Injection (est.) (MMCF)	17,317	74,575	91,892
Water Production (MB)	14,556	150,246	164,802

3.2.3 PBU – Borealis PA

The Borealis pool was discovered in 1969 and production from the Kuparuk Formation was started in November 2001 (Table 2.5). **Engineering analysis to determine the TRR** is described in this section.

Initial development of the Borealis pool began in 2001. The Borealis pool is a PBU satellite targeting an accumulation originally estimated to be 195 to 277 MMBO OOIP of 24.1°API oil. The operator estimates primary recovery to be 13% of the OOIP, secondary recovery another 23%, and 5% for EOR using MI, for a technical recovery of 41% of the OOIP (AOGCC, 2002). **Based on production performance and a recovery of 41%, the indicated OOIP is about 350 MMBO.**

Oil production is processed by the PBU IPA facilities at the maximum rate possible under gas and water handling constraints. The pool started production November 2001 at an initial rate of 19.0 MBOPD and reached a production plateau of over 30 MBOPD by February 2003. The rate was maintained above 30 MBOPD for 17 months before starting on decline. Water flooding started June 2002 and limited gas injection using MI **was started** in June 2004. **A production response to the MI injection has not yet been detected. Approval for field wide miscible gas injection was given by the AOGCC in April 2005. MI now targets about 20% of the reservoir.**

Borealis pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-7. The individual oil production

forecast is tabulated in Appendix A, Table A.1.

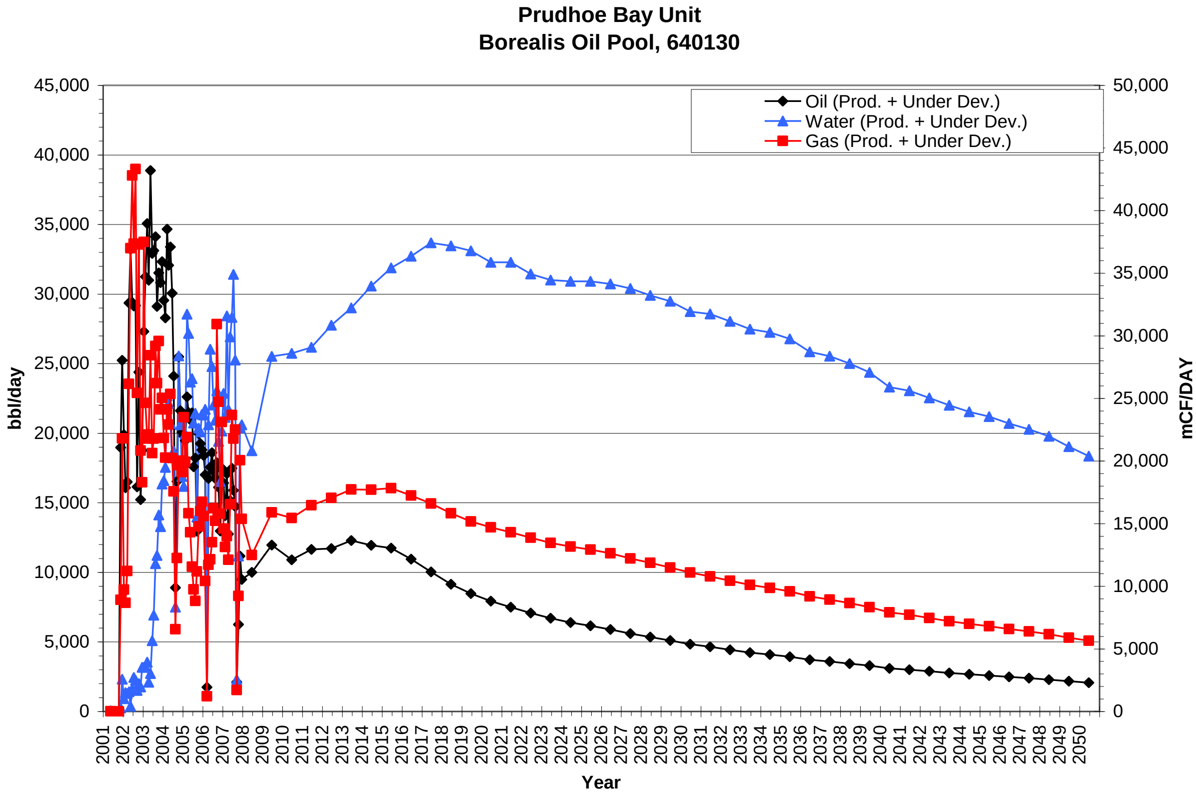

Figure 3-7. Prudhoe Bay Unit–Borealis pool production history and forecasts.

Historical oil production was used to estimate a future oil production rate. **A decline rate of less than 10% per year is now indicated.** The last **four** months of **2007** had a reduction in oil production. **Water cut has increased markedly over the last five years. It is assumed this lower production rate will not continue and the production rate will average about 12,000 BOPD in 2009. It is assumed the development and operating plans[26] will be successful in maintaining the indicated decline rate.** The forecast uses an assumed **final forecast rate of about 1,500 BOPD and gives a TRR of 75,113 MBO, from the current primary and secondary development activities.**

Plans indicate that 5 to 10 additional wells will be drilled on the expanded Z Pad. The average per well recovery is about 4,300 MBO based on the forecast of the current developed area. Assuming 5 additional wells will be drilled, this additional drilling increases TUR by about 21,000 MBO. This results in a total TRR of 96,113 MBO and a total TUR of 144,420 MBO.

[26] ADNR 2008 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Historical recovery versus **GOR and water cut are used to forecast gas and water production** with the response terminated at a 0.90 water cut at depletion. It is assumed that produced gas is used in lease operations with excess gas being used for the MI project.

Borealis pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.4.**

Table 3.4. Borealis pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	48,307	96,113	144,420
NGLs	0	0	0
Gas Production (MMCF)	44,113	148,640	192,753
Gas Injection (est.) (MMCF)	21,454	-	-
Water Production (MB)	33,140	358,986	455,099

Projects Under Evaluation: The use of miscible injection is under evaluation with about 20% of the reservoir volume involved in the process. A production response to the MI injection has not yet been detected. Depending on performance, the EOR process may eventually be expanded to about 40% of the reservoir volume[27]. The expansion of the MI area and the drilling of additional wells on I pad and an east expansion of the Borealis PA are all under evaluation and are described in Section 3.4.1.1. If successful, these projects under evaluation could add about 20,000 MBO of recoverable resources. However, since these projects are under evaluation, these potential recoveries are not included in Table 3.4. The recoveries are included in the Under Evaluation category in Section 3.4.1.1.

3.2.4 PBU – Midnight Sun PA

The Midnight Sun pool was discovered in 1997 and production from the Kuparuk Formation was started in October 1998 (Table 2.5). **Engineering analysis to determine the technically recoverable resource is** described in this section.

The Midnight Sun pool is a recent satellite development targeting an accumulation of between 40 and 60 MMB OOIP of 25.5°API oil (AOGCC, 2000c). The OGIP is 130 BCF with 80 BCF contained in a gas cap. The operator estimates primary recovery to be 14% of the OOIP, secondary recovery another 15 to 25% for a technical recovery of between 29 and 39% of the OOIP (AOGCC, 2000c). Based on available information **and production response**, the ultimate oil recovery is about **37% of an indicated 60 MMBO OOIP**.

The Midnight Sun pool production is processed by the PBU facilities at the maximum rates possible under gas and water handling constraints. **The pool is fully developed with the**

[27] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

existing wells.[28] Waterflooding started in October 2000. The initial rate was 1.9 MBOPD increasing to over 12 MBOPD by May 2002 before starting to decline. Although oil production increased during the last three months of 2004, the performance history indicates the pool is in its decline and the increase in production in 2005 and 2006 will not be sustained. **Water cut increased from less than 15% in July 2007 to over 80% in December 2007.** The oil, water, and gas production history and forecasts are presented in Figure 3-8.

It is anticipated that production will average **1.9 MBOPD during 2008 and decline to an assumed abandonment rate of 0.067 MBOPD resulting in a TRR of 5,739 MBO, and a TUR of 22,351 MBO.**

Midnight Sun pool historical **and future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-8. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

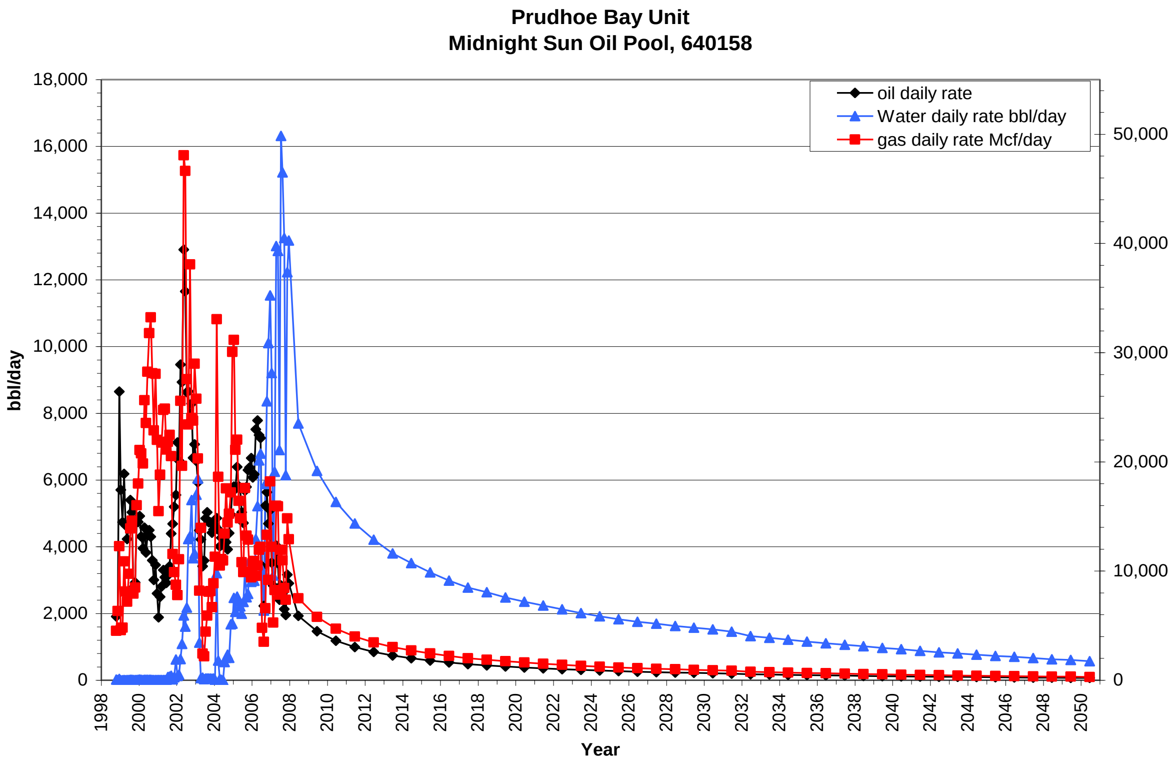

Figure 3-8. Prudhoe Bay Unit–Midnight Sun pool production history and forecasts.

Future water and gas production forecasts are developed from the historical water cut and **GOR data as described in Section 3.1.3**. It is assumed that produced gas is used in lease operations with excess gas injected into the PBU IPA.

Midnight Sun pool historical oil, gas, and water cumulative production **and forecasts**

[28] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.5.

Table 3.5. Midnight Sun pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	16,612	5,739	22,351
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	16,612	5,739	22,351
Gas Production (MMCF)	53,562	23,805	77,367
Gas Injection (est.) (MMCF)	0	0	0
Water Production (MB)	8,596	32,467	41,063

3.2.5 PBU – Orion PA

The Orion pool was discovered in 1968 and production from the Schrader Bluff Formation was started in April 2002 (Table 2.5). **Engineering analysis to determine the technically recoverable resource is described in this section.**

The Orion pool is a PBU satellite development that targets an OOIP accumulation of between **1.07 and 1.78** BBO **OOIP** of heavy oil (PN, 2004k) with a variable gravity of 15 to 22° API. Anticipated primary recovery is **5%** of OOIP plus 15% incremental with secondary recovery. It is assumed the total pool recovery will be about **20%** of the OOIP or about **215** MMBO **of an indicated 1.07 BBO OOIP** under primary and secondary field operations. **If an EOR process initiated in 2006 is successful, recover could be increased by 5% OOIP.**

Production is processed by the PBU IPA facilities under the gas and water handling constraints. Production is from the Schrader Bluff O and N sands with field development using horizontal and multilateral wells. **A total of up to 125 wells is estimated for complete development of the pool, with about one-third being producers.** Development is expected to occur in three phases (AOGCC, 2004). The **initial phase**,Phase I, is **assumed to be completed after three more producers are drilled in 2008.**[29] **Phase I includes a 5 well EOR flood initiated in 2006, but results of the 5-well EOR flood are not yet apparent. Phase II is assumed to be underdevelopment and will require 11 producers, with initial production beginning in 2010. Phase III development includes the drilling of 19 producers and expansion of the EOR flood to the entire field. Phase III is under evaluation and is presented in Section 3.4.1.2**.

The current development, Phase I, totals 31 wells. In December 2007, there were eight active producers and 18 active injection wells. Three additional producers are assumed to be completed in 2008. The pool started first production in April 2002 and

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[29] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

increased erratically to a peak of 14 MBOPD during July 2007. This level is not expected to be maintained, even with the drilling of additional wells in 2008. It is assumed Phase I production will average 10.9 MBOPD in 2008 and then experience decline to an assumed abandonment rate of 0.97 MBOPD by 2050, resulting in a TRR of 50,166 MBO. With about 11,359 MBO recovered through 12/31/2007, the TUR for Phase I is about 61,525 MBO.**

Primary and secondary recovery for Phase II is based on the TUR forecast for the 11 phase I producers. The production profile is patterned after Phase I with a peak rate of 7,200 BOPD during 2015 and 2016. An average per well recovery of 5,125 MBO is used for 11 producers assumed to develop the Phase II area. This results in a Phase II TRR of about 56,363 MBO. The total TRR for Orion Phase I and II is 106,529 MBO, giving a total TUR of 117,888 MBO.

Orion pool historical and **future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-9. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

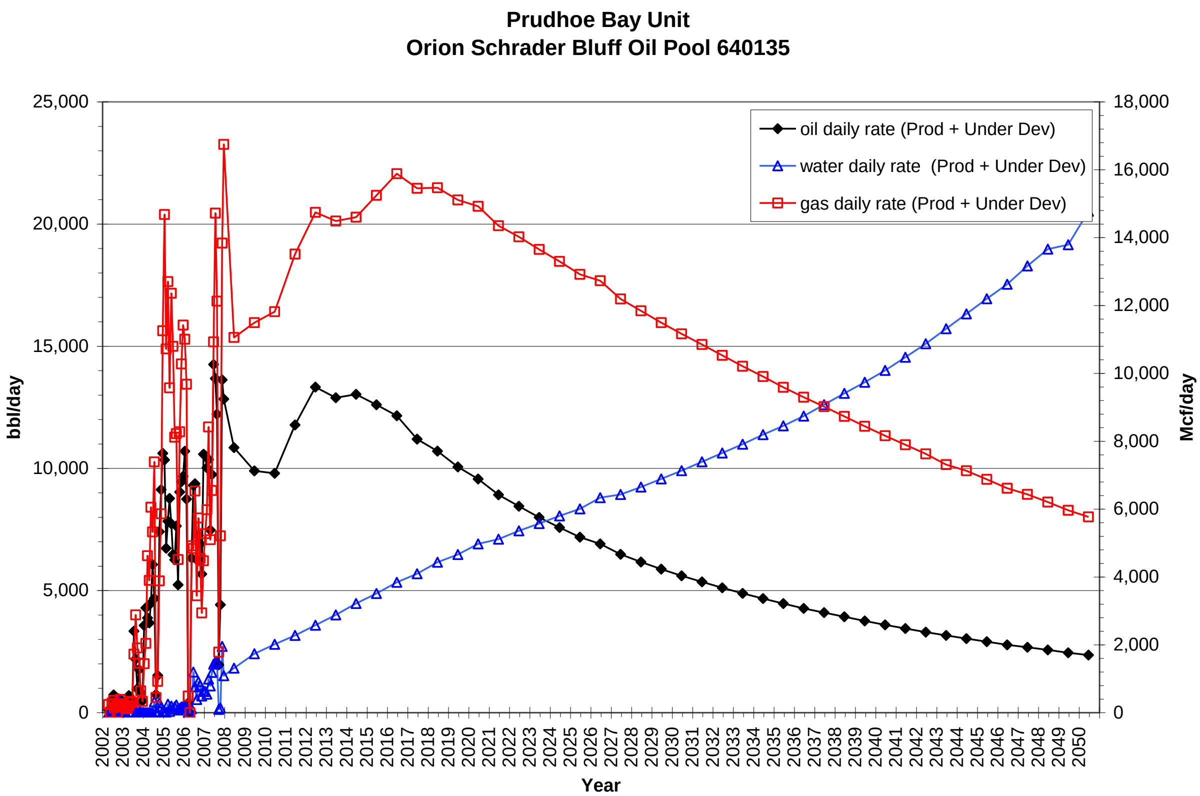

Figure 3-9. Prudhoe Bay Unit–Orion Scharader Bluff oil pool production history and forecasts.

The water cut and **GOR historical data, although limited, are used** to forecast future water and gas volumes **as described in Section 3.1.3**. It is assumed all produced gas is used onsite for lease operations.

Orion pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the Orion pool Phase I and Phase II projects under development as of 1/1/2008 are presented in Table 3.6.**

Table 3.6. Orion pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	11,359	106,529	117,888
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	11,359	106,529	117,888
Gas Production (MMCF)	10,723	173,033	183,756
Gas Injection (est.) (MMCF)	2,003	155,732	157,732
Water Production (MB)	887	159,257	160,144

Projects Under Evaluation: Phase III is under evaluation and includes the drilling of 19 producers and the expansion of the EOR miscible water alternating gas (WAG) process to the entire pool.

The EOR potential is being evaluated (AOGCC, 2004). Results of a 5-well EOR flood initiated in October 2006 are not yet apparent. If EOR proves successful at Orion, an additional 5% OOIP recovery, or 53,500 MBO could be attained. However, since technical success has not been demonstrated, this potential EOR recovery is not included in Table 3.6. The EOR recovery is included in the Under Evaluation category in Section 3.4.1.2.

The total TUR for Phase III is assumed to be about 150,875 MBO which includes 97,375 MBO from the 19 well development drilling program plus 53,500 MBO from the EOR expansion to the entire field. Phase III is under evaluation and the potential recovery is not included in Table 3.6. The Phase III recovery is included in the Under Evaluation category in Section 3.4.1.2.

3.2.6 PBU – Polaris PA

The Polaris pool was discovered in 1969 and production from the Schrader Bluff Formation began in November 1999 (Table 2.5). **Engineering analysis to determine the technically recoverable resource is** described in this section.

The Polaris pool is a PBU satellite development of the Schrader Bluff "O" sand with an estimated OOIP of between **430 MMBO and 580 MMBO** of 20.5°API heavy oil.[30] **Reservoir performance to date indicates the lower OOIP volume is more reasonable. It is assumed**

[30] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

the OOIP is 430 MMBO and that about 70% of this volume (303,700 MBO) is in the producing area consisting of an initial development area and an area under development, and that about 30% (126,300 MBO) is in an area under evaluation. Primary recovery is indicated to be 10% OOIP and 12% incremental with secondary recovery and no EOR potential at this time (AOGCC, 2003). Available information indicates waterflooding will be the only improved recovery technology applied with the reservoir pressure being maintained close to original conditions. It is assumed the **total TUR recovery will be about 22% of the 430 MB OOIP. Production response indicates about 26% recovery from the producing area.**

It is assumed that the producing area consisting of the initial development area and the area under development will be fully developed by 2012 using horizontal and multilateral wells and expanding the waterflood. Production is processed by the PBU IPA facilities. The initial development area started producing in November 1999 and **reached a peak rate of about 5.0 MBOPD in December 2007**.

Polaris pool historical and **future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-10. The individual oil production forecast is tabulated in Appendix A, Table A.1**.

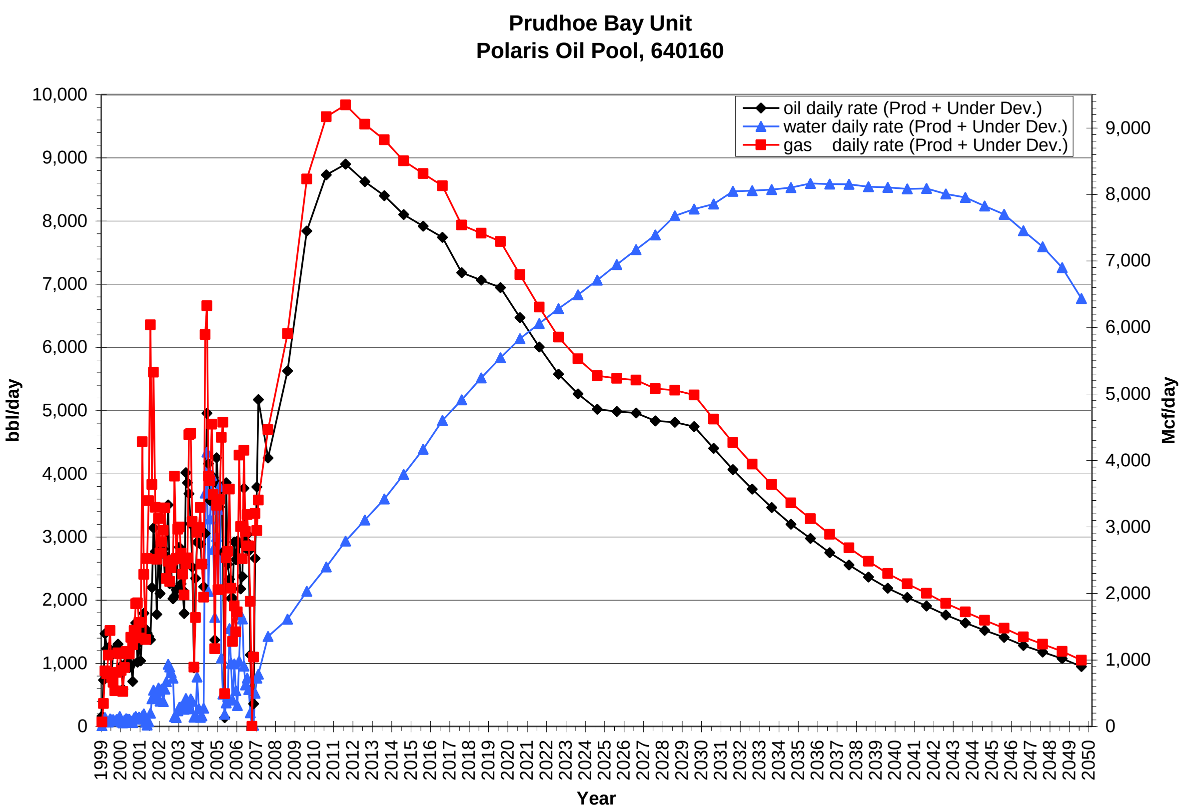

Figure 3-10. Prudhoe Bay Unit–Polaris pool production history and forecasts.

Oil production from the initial development area is assumed to begin to decline immediately to an abandonment rate of 0.09 MBOPD. At abandonment, the TRR for the

initial development area is 17,128 MBO. With oil recovery of 6,543 as of 1/1/2008, this gives a TUR of about 23,671 MBO.

Development of the area under developemnt is assumed to occur at S, W, and M Pads, by the drilling of 14 producers. The average per producing well volume was used as a guide in forecasting the recovery volumes for these 14 wells. The timing and location of these wells will depend on the results of previous wells. It is assumed all 14 new wells will be drilled resulting in a TRR and TUR forecast of 54,580 MBO for the area under development.

The forecasted total TRR for the initial development area and the area under development is 71,708 MBO for a total TUR of 78,251 MBO and a recovery of about 21.9%.

The historical water cut and **GOR data are used to forecast future water and gas volumes as described in Section 3.1.3**. It is assumed all produced gas is used for lease operations.

Polaris pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.7**.

Table 3.7. Polaris pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	6,543	71,708	78,251
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	6,543	71,708	78,251
Gas Production (MMCF)	7,167	75,294	82,461
Gas Injection (est.) (MMCF)	388	0	388
Water Production (MB)	2,036	103,642	105,678

<u>Projects Under Evaluation</u>: The area under evaluation consists of about 30% of the total reservoir volume in an area that has not yet been developed. If this project is successful it could add 15,700 MBO to the Polaris recovery. This potential project is discussed in Section 3.4.1.3.

3.2.7 PBU – Lisburne PA

The Lisburne pool was discovered in 1968 and initial production occurred from the Lisburne Formation in 1981. **Engineering analysis to determine the technically recoverable resources is** described in this section.

The Lisburne pool **produces** from an accumulation of 3,000 MMB OOIP of 27°API oil. **First production occurred in June 1981; however, the pool was produced intermittently**

until January 1985, at which time continuous production commenced. Due to poor reservoir quality, the primary recovery is estimated at 7% (AOGCC, 1985).

Oil production is being processed by the Lisburne PA facility. The Lisburne PA was produced intermittently from two wells until 1985 when fieldwide development occurred. Production increased rapidly under waterflooding as 64 production wells were drilled with peak production occurring in 1990 at slightly over 40 MBOPD. The tight formation and the natural fracturing rendered the reservoir difficult to water flood, with primary depletion occurring with oil moving from tight matrix to the higher permeability natural fractures, resulting in very low recovery efficiencies. Water injection into the Lisburne ceased in December 1989 due to the unsuccessful water flood after a total injection volume of 8.5 MMBW.

Oil from the Lisburne pool is being produced at the maximum rate possible under gas and water handling constraints. The historical and forecast oil, water, and gas productions versus time are shown in Figure 3-11. **Current oil recovery is about 5% of 3 BBO of OOIP. Production improvement plans given in 2007[31] include optimizing field gas offtake, remedial well work, development drilling prospects, and reservoir pressure maintenance operations. Using these plans and new technology in future years, it is believed that ultimate oil recovery can be increased to about 7% of OOIP. Based on available information, it is assumed oil production will average about 9,500 BOPD during 2008 and stabilize at 9,300 BOPD during 2009 and 2010. At that time a low decline rate of about 5% per year will occur for the remaining life. This low decline rate is reasonable because it is a tight reservoir and the pressure maintenance program has been successful. Future recovery is estimated using an initial rate of 9300 BOPD in 2010 and declining at 5% per year to an abandonment rate of 1.66 MBOPD in 2046. This results in oil TRR of 69,790 MBO. Continued gas cycling will increase recovery of NGLs. Future production of NGLs is forecasted by declining the current ratio of barrels of NGLs per MCF gas produced, at about 8% per year. These assumptions give an NGL TRR of 4,610 MB, and result in oil plus NGLs TRR of 74,400 MB, and a TUR of 239,345 MB.**

Lisburne pool historical **and future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-11. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

[31] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

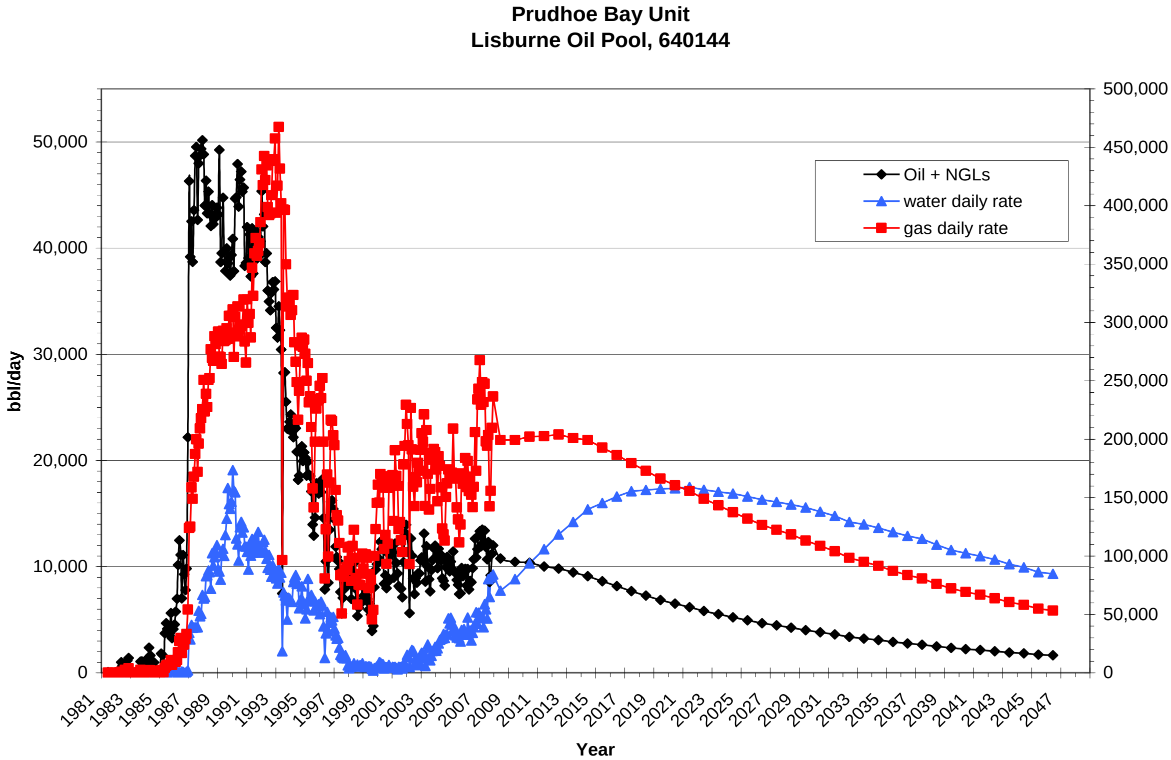

Figure 3-11. Prudhoe Bay Unit–Lisburne pool production history and forecasts.

It is believed most of the injected water has been recovered; hence the majority of future water production will be formation water. The oil recovery factor versus water cut relationship has been updated with new production data and the revised recovery estimate. Based on recent water cut performance, water production is expected to continue to increase before beginning to decline in 2020. This revised relationship provides reasonable estimates of future water production. Currently, about 60% of produced gas is reinjected for pressure maintenance and NGL recovery. The remaining Gas production is used for lease operations and export to Point McIntyre for GOR use. Excess gas from Point McIntyre, Niakuk, and West Beach is also injected. Some gas may be available for future gas sales.

Lisburne pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.8**.

Table 3.8. Lisburne pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	149,714	69,790	219,504
NGL Production (MB)	15,231	4,610	19,841
Oil and NGLs (MB)	164,945	74,400	239,345
Gas Production (MMCF)	1,646,612	1,820,130	3,466,742

Gas Injection (est.) (MMCF)	1,603,609	1,223,236	2,826,845
Water Production (MB)	42,352	196,230	238,582

3.2.8 PBU – Niakuk PA

The Niakuk pool was discovered in 1985 and production from the Kuparuk C sandstone and Sag River Formations was started in 1994 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is** described in this section.

The Niakuk **pool** started producing in April 1994 from an accumulation with an OOIP of 219 MMB of 24.9°API oil (AOGCC, 1994). The reservoir **was** expected to recover 4% by primary and 36% by secondary, for 40% recovery of the OOIP. **The production response to date and the calculated TUR indicate that recovery will be 46%. No EOR process is under evaluation at this time, and no EOR potential recoverable resources are included.**[32]

Production is processed by Lisburne PA facilities at the maximum rate possible under gas and water constraints. Production reached a maximum of over 30 MBOPD in 1996, and exceeded 20 MBOPD through mid 2000. Oil production has established a decline since early 2001 of about 15% per year while water production has increased significantly over time. Historical and forecast oil, gas, and water production are presented in Figure 3-12. **It is assumed workovers, reservoir management and perhaps some redrills will** moderate the decline.

Niakuk pool historical **and future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-12. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

TRR volumes are forecasted **from a current production rate of about 4.5 MBOPD, to an abandonment rate of 0.400 MBOPD. This results in TRR of 14,013 MBO. NGL recoverable resources are estimated using the decline in the historical recovery factors. This results in an NGL TRR of 0.291 MB and a total liquid TRR of 14,304 MB and a TUR of 101,630 MB**.

The gas and water forecasts are based on historical data as described in Section 3.1.3. It is assumed produced gas is consumed by lease operations with any excess gas being injected into the Lisburne reservoir.

[32] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

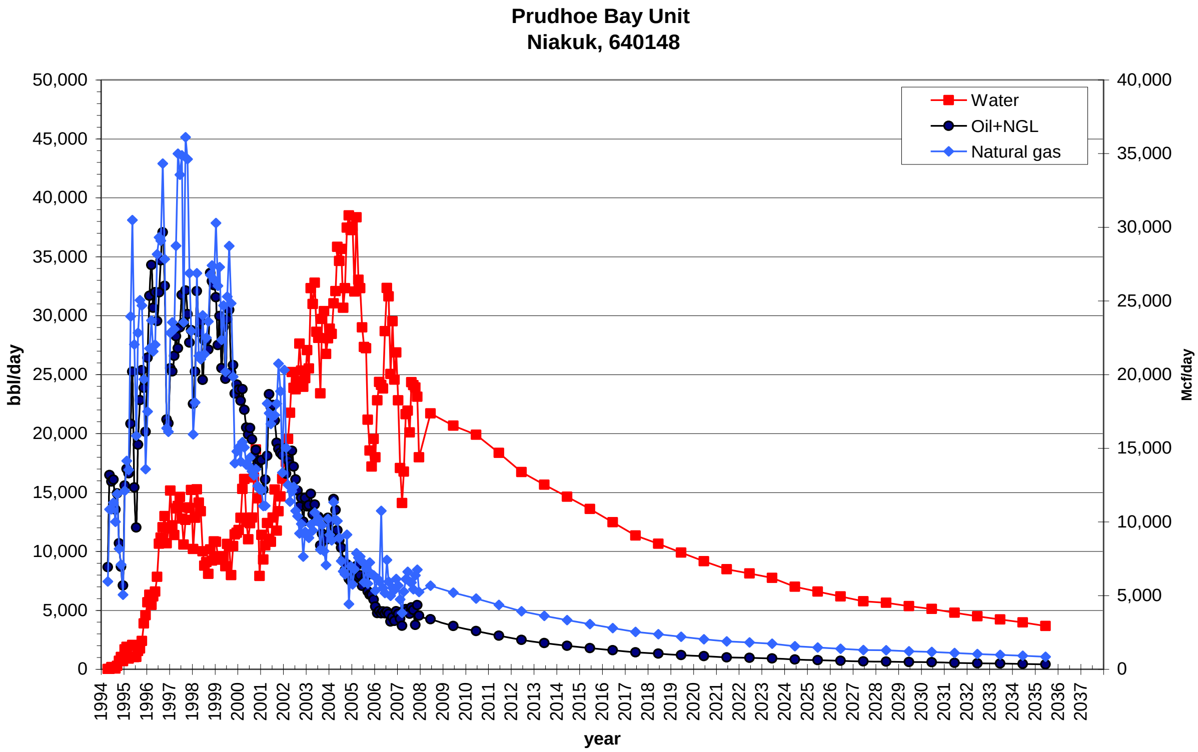

Figure 3-12. Prudhoe Bay Unit–Niakuk pool production history and forecasts.

Niakuk pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.9.**

Table 3.9. Niakuk pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	86,249	14,013	100,262
NGL Production (MB)	1,077	291	1,368
Oil and NGLs (MB)	87,326	14,304	101,630
Gas Production (MMCF)	74,246	23,948	98,194
Gas Injection (est.) (MMCF)	0	0	
Water Production (MB)	84,394	102,865	187,259

3.2.9 PBU – North Prudhoe Bay PA

The North Prudhoe Bay pool was discovered in 1970 and production from the Ivishak Sandstone Formation was started in 1993 (Table 2.5). The OOIP is **12 MMBO** (AOGCC, 1994b). The production test started in 1993 and produced a total of about 2 MMB before being shut in. **No additional recoverable oil is attributed to the North Prudhoe Bay pool.**[33]

North Prudhoe Bay pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-13. The individual oil production forecast is tabulated in Appendix A, Table A.1.

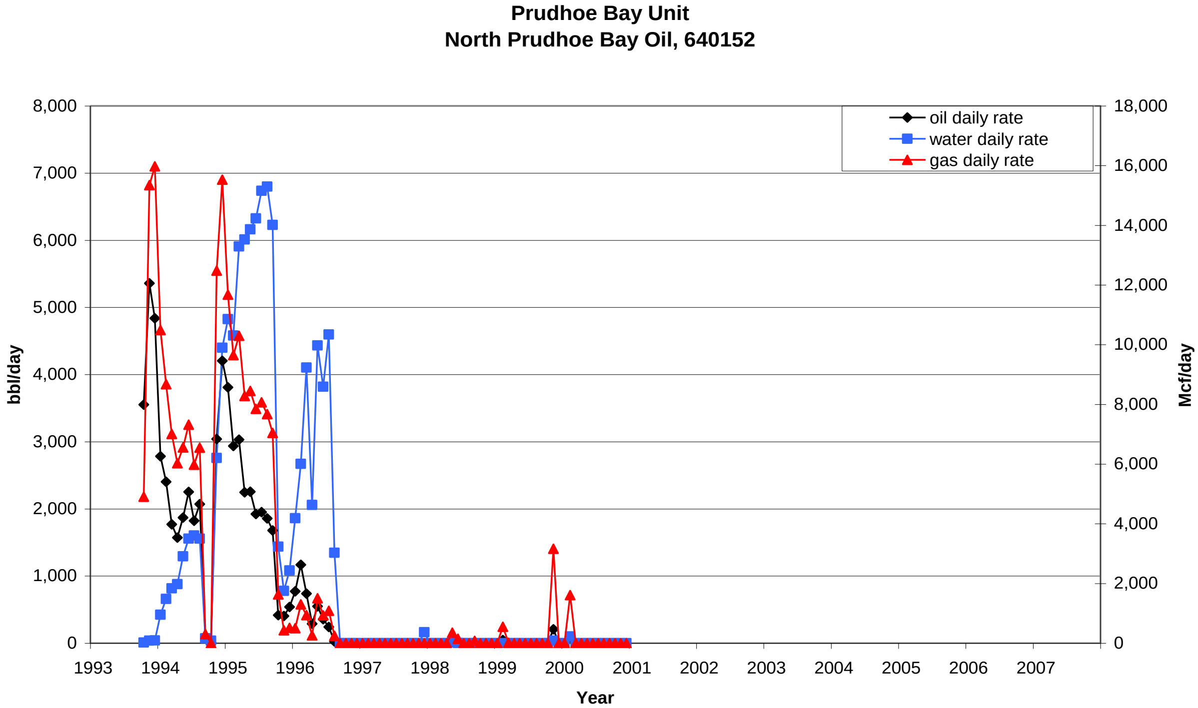

Figure 3-13. Prudhoe Bay Unit–North Prudhoe Bay pool production history.

North Prudhoe Bay pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.10.

Table 3.10. North Prudhoe Bay pool production statistics as of 1/1/2008.

Variable	Volume
Cumulative oil recovery	1,985 MBO
Cumulative NGL recovery	85 MB
Cumulative oil and NGL	2,070 MBO
Cumulative gas production	6,616 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	2,498 MB

[33] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

3.2.10 PBU – West Beach PA

The West Beach pool was discovered in 1976 and production from the Kuparuk C Sandstone Formation was started in 1993 (Table 2.5). The OOIP is between 10 and 65 MMBO (AOGCC, 1993). The historical oil, gas, and water production is presented in Figure 3-14. The production totaled **3.4** MMBO **and 220 MB NGLs through the end of 2007 with no sustained production since the** 2nd quarter of 2001. **No additional recoverable oil is attributed to the West Beach pool.**[34]

West Beach pool historical **and future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-14. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

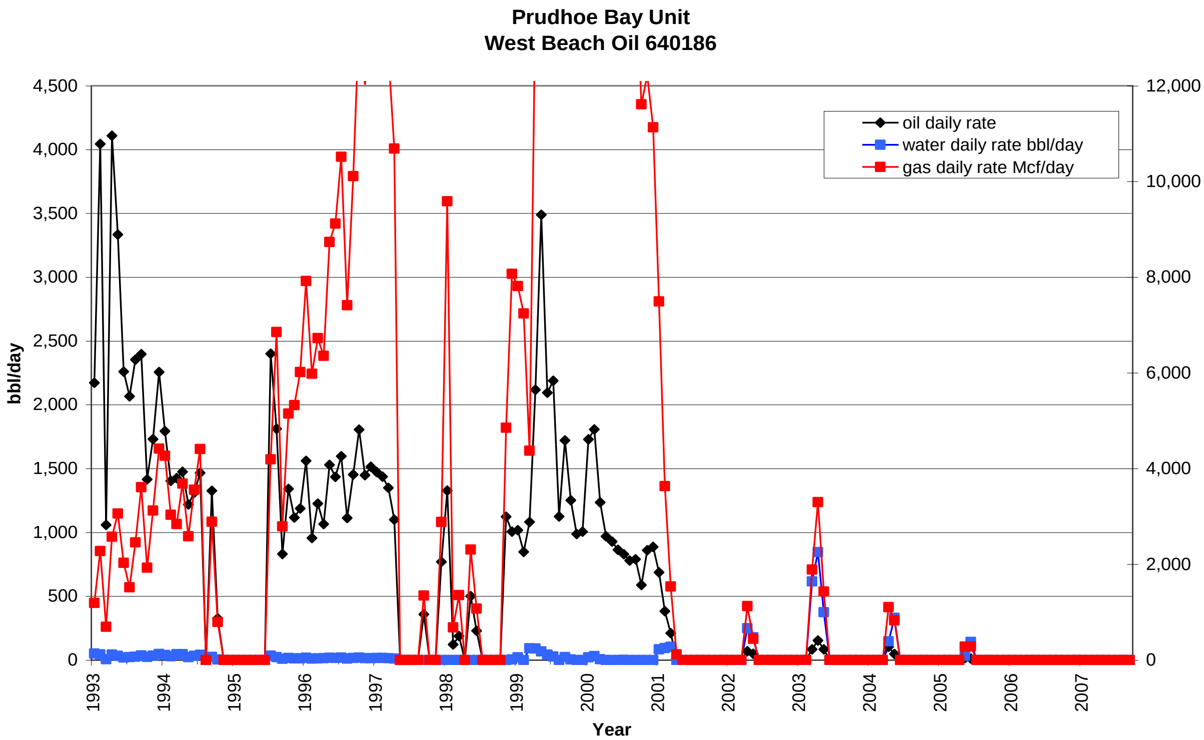

Figure 3-14. Prudhoe Bay Unit–West Beach pool production history.

West Beach pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.11.

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[34] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Table 3.11. West Beach pool production statistics and forecasts as of 1/1/2008.

Variable	Volume
Cumulative oil recovery	3,362 MBO
Cumulative NGL recovery	220 MB
Cumulative oil and NGL	3,582 MBO
Cumulative gas production	20,029 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	143 MB

3.2.11 PBU – Point McIntyre PA

The Point McIntyre pool was discovered in 1988 and production from the Kuparuk C Sandstone Formation was started in 1993 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is** described in this section.

The Point McIntyre reservoir **was initially reported to have an OOIP of 750 to 800** MMBO of 27°API oil[35]. Recovery is estimated at 20 to 25% primary with secondary processes increasing recovery to 42 to 45% of OOIP. The enhanced recovery project is estimated to increase recovery by 6% for a total recovery of 48 to 51% of OOIP (AOGCC, 1993b and 2000b). **Based on production performance to date, the OOIP appears to be higher than initially reported.**

The Point McIntyre pool started first production in November 1993 at an initial rate of 46.6 MBOPD. Production is processed by the Lisburne PA and the PBU Gathering Center facilities. Improved oil recovery operations began with produced gas reinjected upon the onset and water injection started in July 1994. Production rapidly climbed to over 160 MBOPD by June 1996 with production averaging about 162 MBOPD for 17 months before starting to decline November 1997. **Since January 2002, the decline rate has markedly lessened. Production decline has been rather uniform except for part of 2006 and 2007 when a pipeline problem caused shut down of all wells on PM 1 drillsite.** Historical and forecast oil, gas, and water production is presented in Figure 3-15. Cumulative recovery **through December 2007** is **404** MMBO and the project is still producing **30** MBOPD, indicating that the **initial** estimate of OOIP is conservative. **Based on a recovery factor of 51% and field performance to date, an OOIP of 1,120 MMBO appears to be more reasonable. An OOIP of 1.120 BBO was assumed for this analysis.**

Point McIntyre pool historical and future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-15. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

Future recoverable resources and total recovery volumes are based on the production performance with oil production exhibiting a low rate of decline of about 5% per year over the last three years. It is assumed this low decline will **be maintained through a combination of**

[35] AOGCC Conservation Order No. 317.

workovers, redrills, new wells, and expansion of the EOR process[36]. Recoverable resources are forecast using an initial rate of 27.0 MBOPD for 2008 with production declining to an abandonment rate of 2.1 MBOPD in 2050. This results in a TRR of 154,510 MBO.

The NGL forecast **uses the historical NGL yield data, BBLNGL/MCF, for Point McIntyre. The yield data is used with forecasted gas volumes to obtain yearly NGL volumes. This results in a TRR for NGLs of 2,608 MB. The total TUR for oil and NGLs is 571,052 MB**.

Water and gas production forecasts were developed from historical data as described in Section 3.1.3.

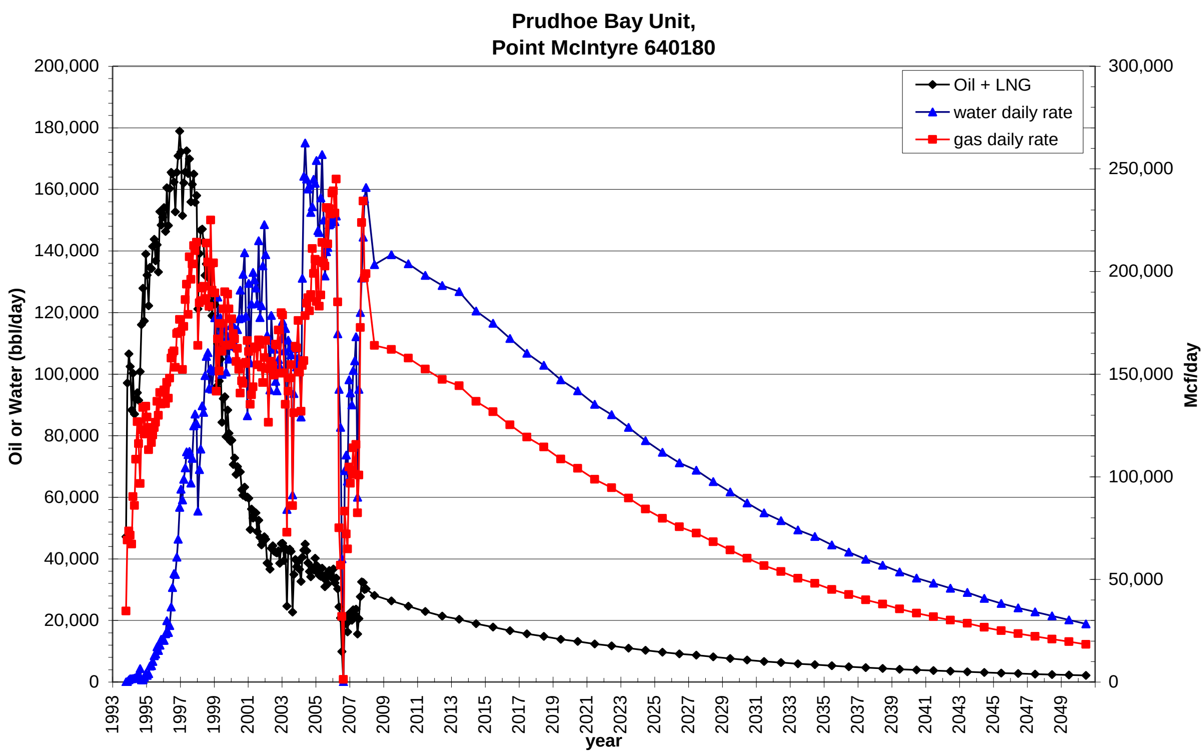

Figure 3-15. Prudhoe Bay Unit–Point McIntyre pool production history and forecasts.

Point McIntyre **pool** historical oil, gas, and water cumulative **production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.12.**

Table 3.12. Point McIntyre pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically	Ultimate Technically

[36] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

		Recoverable	Recoverable
Oil Production (MBO)	404,422	154,510	558,932
NGL Production (MB)	9,512	2,608	12,120
Oil and NGLs (MB)	413,934	157,118	571,052
Gas Production (MMCF)	810,799	1,184,890	1,995,689
Gas Injection (est.) (MMCF)	689,340	1,280,660	1,970,000
Water Production (MB)	463,776	1,086,010	1,549,786

3.2.12 Prudhoe Bay Unit – Raven PA

The Raven PA was discovered in 1995 and production is from the Ivishak and Sag River Formation (Table 2.5). Engineering analysis to estimate TRR is described in this section.

The Raven PA is a PBU satellite located around the Heald Point drillsite.[37] The OOIP is assumed to be about 14 MMBO. Based on the performance to date the TUR will be about 30% of the OOIP volume. Production was started in March 2005 and a waterflood for production enhancement was begun in October 2005.

Production is processed at the Lisburne Production Center. The pool started producing in March 2005 at an average of about 1.0 MBOPD and by February 2007 had reached a peak of about 3.0 MBOPD. Production has been declining since and oil recovery totaled about 1.7 MMBOPD at year end 2007.

Raven pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-16. The individual oil production forecast is tabulated in Appendix A, Table A.1.

[37] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

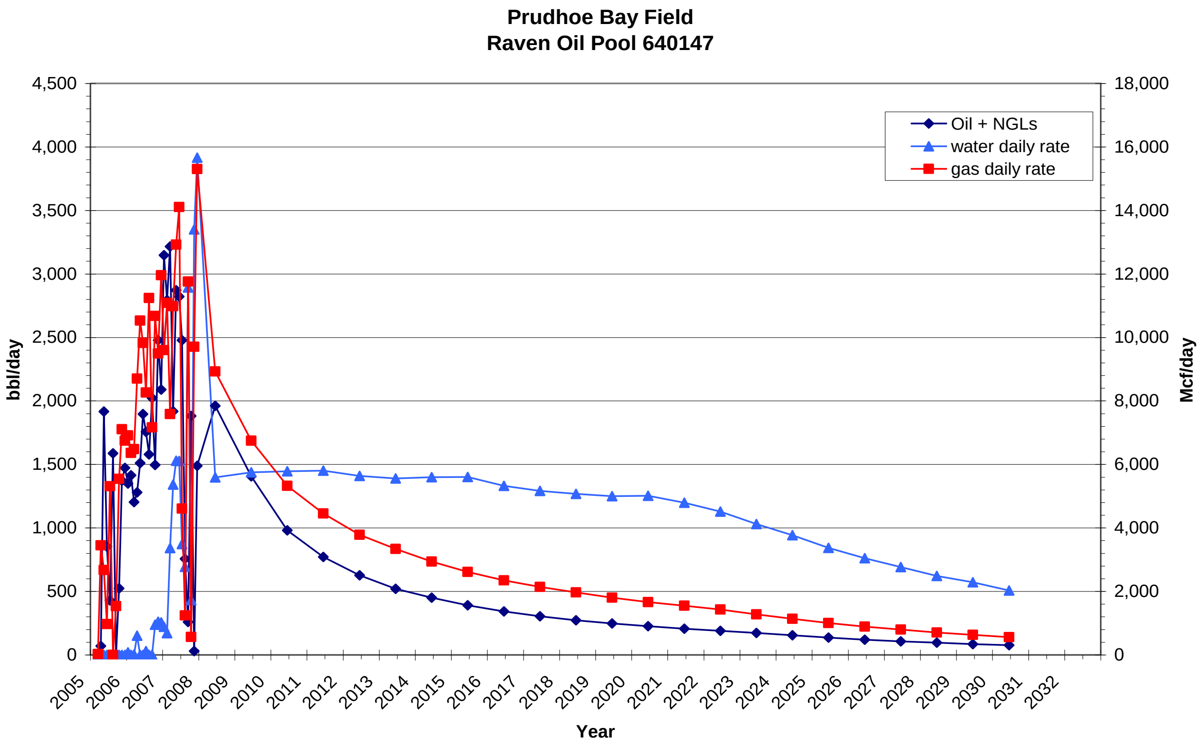

Figure 3-16. Prudhoe Bay Unit–Raven pool production history and forecasts.

As no additional development plans have been announced,[39] it is assumed production will continue to decline. Future recovery is estimated from an initial rate of about 1.6 MBOPD at 1/1/2008, to a final rate of 0.06 MBOPD in 2030. This results in a TRR of about 2,560 MBO and TUR of 4,118 MBO.

The future production of NGLs was made using Raven historical data even though it was limited. A simple approach was used of extrapolating two years production values. An initial rate of 0.15 MBOPD was declined to a final rate of 0.01 MBOPD in 2030. This results in an NGL TRR of 352 MBLs and a TUR of 435 MBLS.

This results in a total TRR of about 2,912 MBLs and a TUR of about 4,553 MBLs.

Although limited, Raven gas and water production histories were used with the oil recovery factors to estimate future gas and water volumes. Gas is used for lease operation or is injected into the Lisburne and Point McIntyre fields.

Raven pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.13.

Table 3.13. Raven pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	1,558	2,560	4,118
NGL Production (MB)	83	352	435
Oil and NGLs (MB)	1,641	2,912	4,553
Gas Production (MMCF)	7,662	21,173	28,795
Gas Injection (est.) (MMCF)	0	0	0
Water Production (MB)	571	9,496	10,067

3.2.13 Duck Island Unit – Endicott PA

The Endicott pool was discovered in 1978 and production from the Kekiktik Conglomerate Formation was started in 1986 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is** described in this section.

The Endicott pool was the first ANS offshore project. It was developed from a man-made island that is connected to shore with a gravel causeway. It targets an accumulation of 1,059 MMB OOIP of 23ºAPI oil[38]. **Available** total recovery including primary, incremental secondary and EOR **estimates** ranges from about 48 to 53% (ADNR, 2004). These recovery factors give a TUR between 508 and 560 MMBO. **However, cumulative recovery through December 2007 is 443 MMBO, suggesting that the recovery factor may be higher for an OOIP of 1,059 MMBO. A recovery factor of 56% was assumed for this analysis.**

Production started in August 1986 and increased to over 100 MBOPD by November 1987. Production is processed by the Duck Island Unit (DIU) IPA facilities. Water injection started in January 1988. Oil production was maintained at an average rate of 103.9 MBOPD from November 1987 through January 1994 before starting to decline. The pool **averaged 12.6 MBOPD during 2007.**

Endicott pool historical and future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-17. The individual oil production forecast is tabulated in Appendix A, Table A.1**.

[38] ADNR 2004 POD.

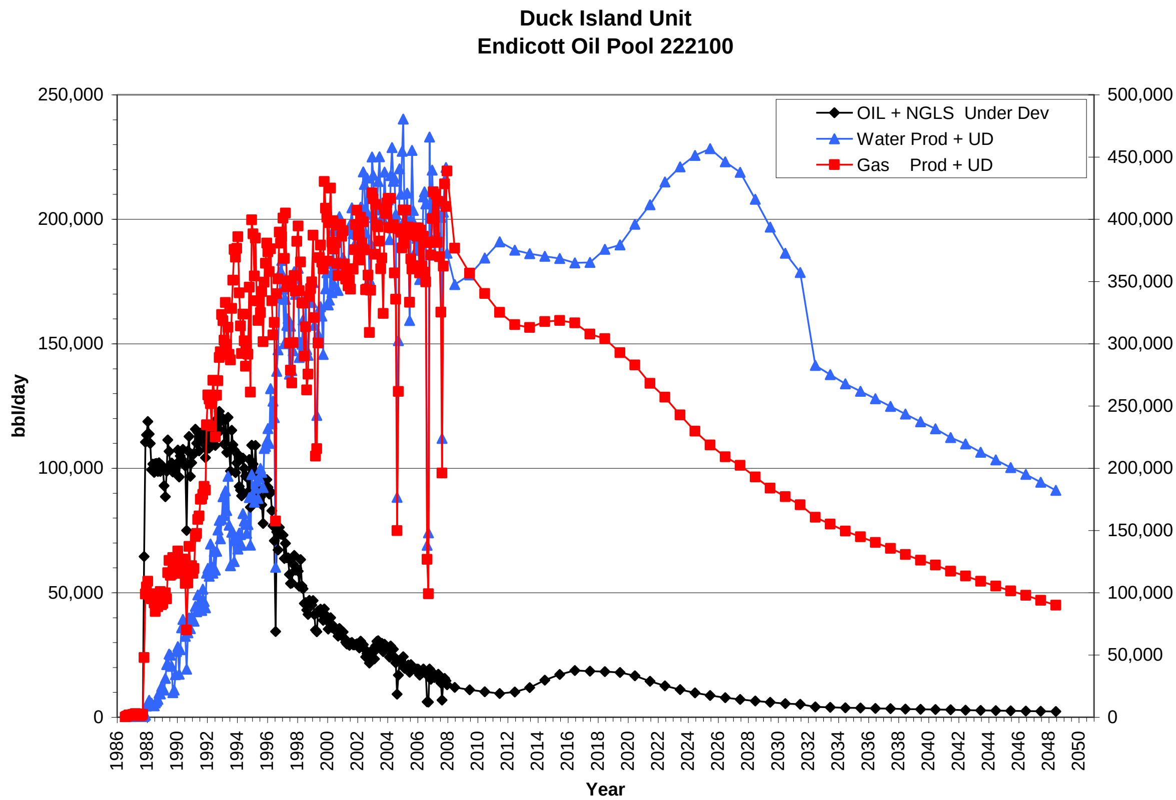

Figure 3-17. Duck Island Unit–Endicott pool production history and forecasts.

The forecast of **technically recoverable oil and gas** is based on the production performance of the last five years with a decline of about 10% per year. It is assumed this decline can be sustained by an active program of well workovers, redrills, and the continued success of the waterflood. **Recoverable resources are estimated using a 12.0 MBOPD rate for 2008 and an abandonment rate of 2.25 MBOPD in 2050. This results in a TRR of 79,398 MBO. Project plans include expansion of the EOR project and additional drilling opportunities.[39] It is assumed these efforts will be successful. It is assumed the increased recovery will commence in 2012. This results in a TRR of 42,500 MBO or about 4% of OOIP.**

This results in an oil TRR of 121,898 MBO, and a TUR of 565,217 MBO.

Future production of NGLs is based on the last eight years of NGL and produced gas volumes. The NGL yield factor (bbl NGL/MCF gas produced) has declined from 0.0102 bbl/MCF to **0.0057** bbl/MCF. **That decline history is used with the future forecast of produced gas volumes to forecast an NGL TRR of 3,454 MB, giving an NGL TUR of 26,375 MB. The TRR for oil and NGLs is about 125,352 MB resulting in a TUR for oil and NGLs of about 591,592 MB.**

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[39] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

The **gas and water production forecasts are based on the historical production as described in Section 3.1.3.** All gas is used for lease operations or for enhanced oil recovery.

Endicott pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.14.**

Table 3.14. Endicott pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	443,319	121,898	565,217
NGL Production (MB)	22,921	3,454	26,375
Oil and NGLs (MB)	466,240	125,352	591,592
Gas Production (MMCF)	2,223,249	3,143,756	5,367,005
Gas Injection (est.) (MMCF)	1,992,352	2,829,380	4,821,732
Water Production (MB)	943,286	2,440,499	3,383,785

3.2.14 Duck Island Unit – Eider PA

The Eider pool of the DIU (Eider PA) was discovered in a 1998 (Table 2.5) and production started in 1998 from the Ivishak Sandstone Formation (ADNR, 2002). The production totaled **2.8 MMBO through December 2007**. The OOIP is 13.2 MMB of 23ºAPI oil (AOGCC, 2000c). Eider historical oil, gas, and water production is shown in Figure 3-18. As a result of no **oil production since 2006, no additional recoverable oil is** attributed to this development.[40]

Eider pool historical oil, gas, and water **productions versus time are shown graphically in Figure 3-18.**

[40] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

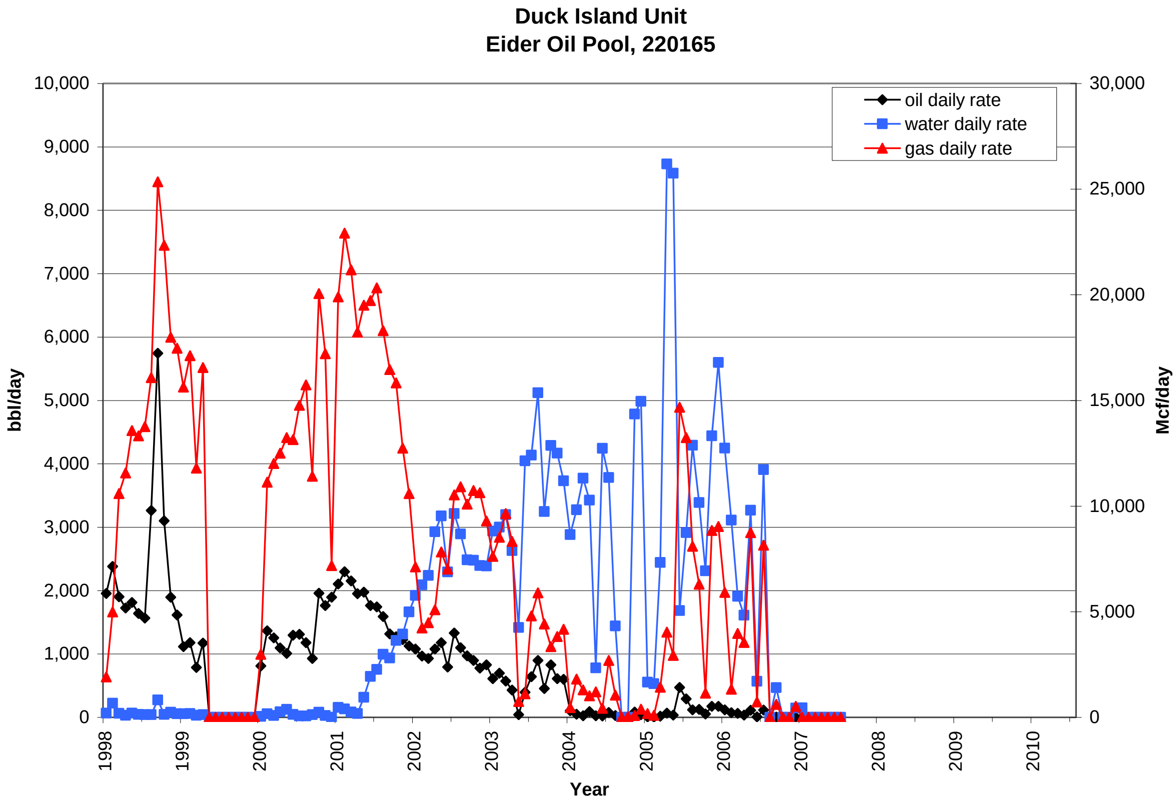

Figure 3-18. Duck Island Unit–Eider pool production history.

Eider pool historical oil, gas, and water **cumulative productions are presented in Table 3.15.**

Table 3.15. Eider pool production statistics as of 1/1/2008.

Variable	Volume
Cumulative oil recovery	2,754 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	2,754 MBO
Cumulative gas production	26,520 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	5,498 MB

3.2.15 Duck Island Unit – Sag Delta North PA

The Sag Delta North PA of the DIU **(called the Ivishak pool by the AOGCC)** was discovered in 1982 (Table 2.5) and consists of two formations, the Ivishak Sandstone and the Alapah Limestone of the Lisburne Group (AOGCC, 1991). Commingled production began in 1989 from an OOIP of about 18 MMBO in the Ivishak/Alapah Formations[41]. Production totaled

[41] AOGCC Pool Order No. 275.

8.1 MMBO through December 2007. **The one producing well was shut down in March 2007. No additional recoverable oil is** attributed to this PA[42].

Sag Delta North pool historical oil, gas, and water productions versus time are shown graphically in Figure 3-19.

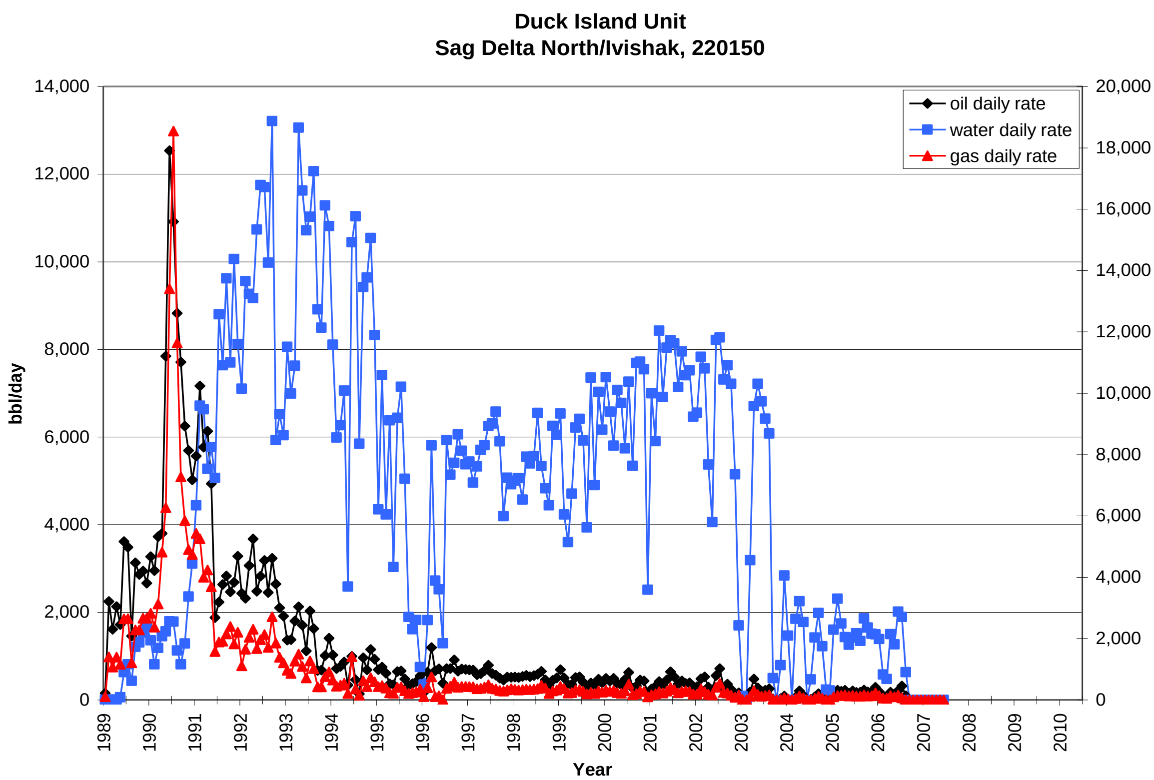

Figure 3-19. Duck Island Unit–Sag Delta North pool production history and forecasts.

Sag Delta North pool historical oil, gas, and water **cumulative productions are presented in Table 3.16.**

Table 3.16. Sag Delta North pool production statistics as of 1/1/2008.

Variable	Volume
Cumulative oil recovery	8,066 MBO
Cumulative NGL recovery	112 MBO
Cumulative oil and NGL	8,178 MBO
Cumulative gas production	6,587 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	32,292 MB

[42] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

3.2.16 Northstar Unit – Northstar PA

The Northstar pool was discovered in 1984 and was known as Seal Island after discovery by the Seal #1 well (Table 2.5, ADNR, 2004b). After the Northstar Unit (NU) was formed, production from the Sag River/Ivashak Formation was started in 2001. NU is a recent offshore development, and is located in state of Alaska and federal waters of the Beaufort Sea. Development is from a totally contained offshore island and connected to shore by the first subsea pipeline on the ANS. **Engineering analysis to determine the technically recoverable resources is** described in this section.

Northstar pool development targets an accumulation of 285 MMB OOIP of 43 to 45°API oil (AOGCC, 2001b). It contains significant associated gas and a 7 BCF gas cap. Estimated primary recovery is 36.1%, with gas cycling providing an incremental 13.9% recovery, water flooding 2%, and miscible injectant an additional 12.5% incremental recovery **for a total recovery of 54.6%**. A TUR of 184 MMBO is indicated from the recovery factors and the OOIP estimate (AOGCC, 2001b). **However, the indicated OOIP appears to be low based on production performance. A more likely volume is about 375 MMB OOIP, which was assumed for this analysis.**

Produced fluids are processed by the Northstar facility. Production started November 2001 at an initial rate of 11.6 MBOPD rapidly increasing to over 60 MBOPD by June 2002. Production for **2004 averaged 68.5 MBOPD**. **Production for 2007 averaged 38 MBOPD. Production has peaked and will continue to decline to an abandonment rate of 0.480 MBOPD in 2050**. This results in a TRR of **82,195 MBO** and a TUR of about **204,585 MBO**.

Water and gas production forecasts are based on GOR versus recovery factor and WC versus recovery factor data from historical production. It is assumed all gas production is used for lease operations and the balance injected for gas cycling and EOR purposes. **Approximately 134 BCF of outside gas has been injected into the reservoir for EOR[43] It is assumed the import of gas will continue.**

Northstar pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-20. The individual oil production forecast is tabulated in Appendix A, Table A.1.

[43] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

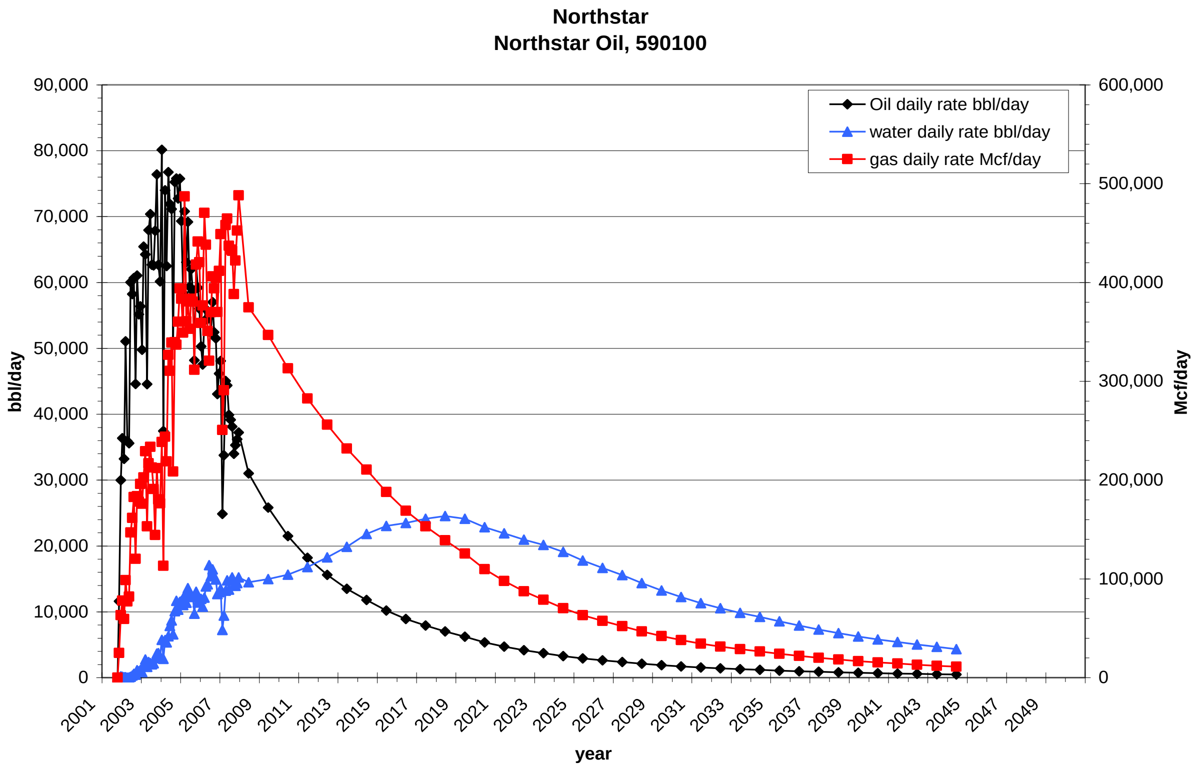

Figure 3-20. Northstar Unit–Northstar pool production history and forecasts.

Northstar **pool** historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.17**.

Table 3.17. Northstar pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	122,390	82,195	204,585
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	122,390	82,195	204,585
Gas Production (MMCF)	661,015	1,376,950	2,037,965
Gas Injection (est.) (MMCF)	798,116	1,399,974	2,198,090
Water Production (MB)	18,171	189,536	207,707

3.2.17 Badami Unit – Badami Sand Field

The Badami pool was discovered in 1990 and is located 35 miles east of PBU. Production began from the Badami sand in 1998. The OOIP is assumed to be 300 MMBO. The field operation was suspended during August 2003 after averaging about 1.3 MBOPD for 2003, as an uneconomical operation.

In September 2005, the operator restarted production for a test period of up to three years. Production operations were again suspended in August 2007 after 24 months of operation.[44] The unit recovered 851,355 BO during that time period. Production totaled 5.2 MMBO through December 2007. It was again shut down for further study.

During the test period the unit averaged about 1,150 BOPD, with a final rate of about 600 BOPD. Until the Unit can produce at a higher rate than 2.0 MBOPD, the project is believed to be marginally profitable at best. The operator is currently working with potential partners on possible actions to return the project to economic production (PN, 2008i). Until such planning proves to be successful, no recoverable resources are estimated for this Unit.

Badami pool historical oil, gas**, and water productions versus time are shown graphically in Figure 3-21**.

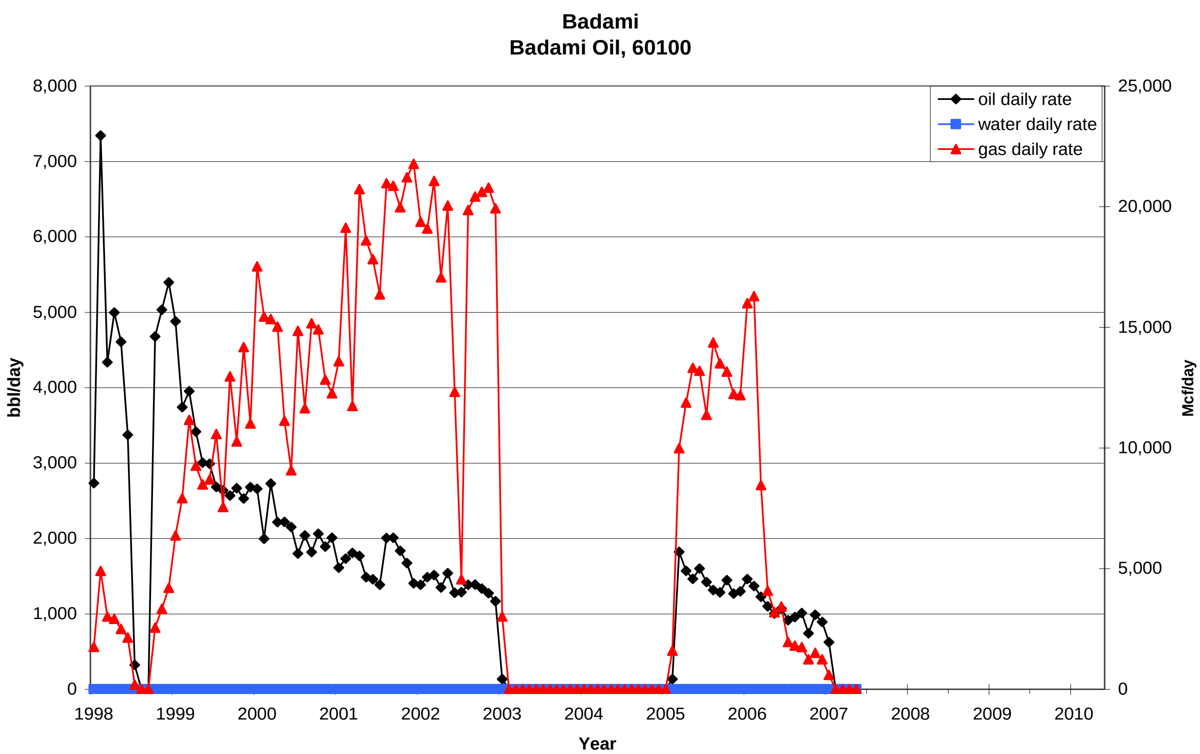

Figure 3-21. Badami pool production history.

Badami pool historical oil, gas, and water **cumulative productions are presented in Table 3.18**.

[44] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Table 3.18. Badami pool production statistics as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	5,198	0	5,198
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	5,198	0	5,198
Gas Production (MMCF)	28,625	0	28,625
Gas Injection (MMCF)	20,512	0	20,512
Water Production (MB)	0	0	0

3.2.18 Kuparuk River Unit – Kuparuk River PA

The Kuparuk River pool was discovered in 1969 and production from the Kuparuk Formation was started in 1981 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is** described in this section.

The Kuparuk River pool was the second field to be developed on the North Slope with an OOIP of 5.69 BBO of 24°API oil and an OGIP of about 1.7 TCF (AOGCC, 1994c). Recovery **was** estimated at 20% primary, 20% incremental secondary, and 8% EOR for a total recovery of 48% of the OOIP**, or a TUR of about 2.73 MMBO**.

The Kuparuk River pool was unitized in December 1, 1981, as the Kuparuk River Unit (KRU) (AOGCC, 1991b). First production began in December 1981 at an initial rate of 35.8 MBOPD. Production is processed by the Kuparuk River IPA facilities. Both gas injection and water injection commenced within 14 months of initial production. Production was increased to 300 MBOPD by February 1988, and averaged about 310 MBOPD for a little more than seven years. Production began to decline in May 1995 and reached **118 MBOPD** in December **2007**.

Kuraruk River pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-22. The individual oil production forecast is tabulated in Appendix A, Table A.1.

Performance history and future recovery plans are used to estimate future recoverable resources. Production has declined at less than 5% per year over several years as a result of EOR success, expanded recovery areas, new drilling, redrilled wells, and well workovers. The estimate of TRR for the current development is made using the production of 118 MBOPD in December 2007 and declining it to an assumed abandonment rate of about 24.6 MBOPD in 2050. This results in a TRR of 909,543 MBO for the current development, and a TUR of 3,019,813 MBO including NGLs.

Plans are for MI process for EOR to be expanded to new areas, additional satellite areas will be developed, and the drilling and workover programs will continue until late in the field life.[45] These Plans are assumed to increase recovery by about 1% of OOIP or about 56.7 MMBO. This volume has been forecasted with initial production of about 7.0 MBOPD in 2012 and declining to about 1.86 MBOPD in 2050. This results in a TRR of 56,720 MBO for the additional planned activities.

Based on the production performance to date and the estimated future recoveries, the total recovery factor appears to be about 54%. This gives a total TRR of 966,263 MBO and a TUR of 3,076,470 MBO.

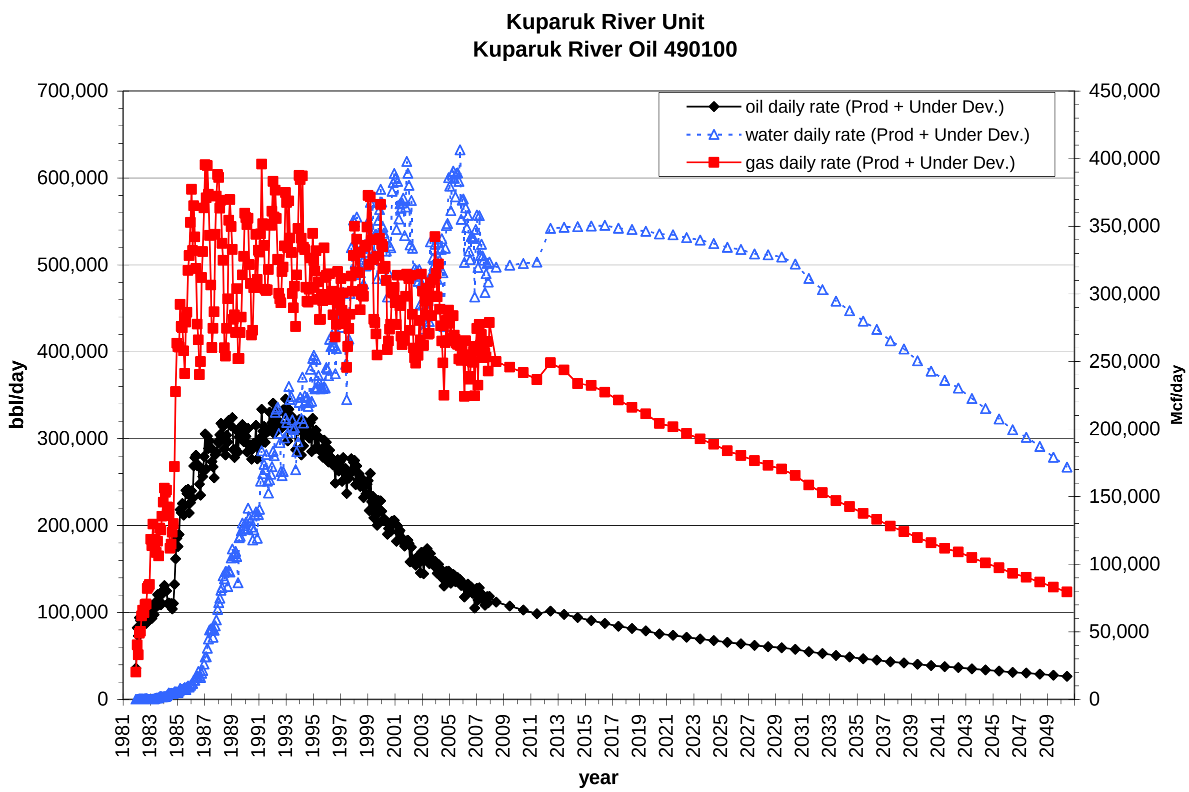

Figure 3-22. Kuparuk River Unit–Kuparuk River pool production history and forecasts.

The water and gas production forecast are based on historical production as described in Section 3.1.3. All gas is used for lease operations or for enhanced oil recovery.

Kuparuk River pool historical oil, gas, and water **cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.19**.

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[45] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Table 3.19. Kuparuk River pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	2,110,207	966,263	3,076,470
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	2,110,207	966,263	3,076,470
Gas Production (MMCF)	2,668, 606	2,612,058	5,280,664
Gas Injection (est.) (MMCF)	2,128,336	2,089,646	4,217,982
Water Production (MB)	3,064,978	7,135,974	10,200,952

3.2.19 Kuparuk River Unit – Meltwater PA

The Meltwater pool was discovered in 2000 and production from the Bermuda Sandstone was started in November 2001 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is described in this section.**

The Meltwater pool is a KRU satellite development targeting an accumulation of 132 MMBO OOIP of 37ºAPI oil. Recovery factors are estimated at 18% primary, 11% secondary, and 9% EOR for a total recovery factor of 38% (AOGCC, 2001c). **Based on current reservoir knowledge, it appears the OOIP estimate is high.** It is assumed the pool is fully developed and the continued use of miscible water-alternating gas (MWAG) will be successful.[46] It is assumed some infill wells, redrills, and workovers will be required during the future operating life.

Production is processed by the KRU IPA facilities. Production peaked at just over 11.0 MBOPD in May 2002 and declined to about 4.0 MBOPD in December 2003. Production then increased to about 8.0 MBOPD in **October** 2004**, and began to decline immediately**. **Production in December 2007 was about 2.7 MBOPD and continues to decline, but at a lower rate. It is assumed the decrease in decline rate is a result of success from the secondary/EOR processes employed, and well workovers and drilling. It is assumed that these efforts will continue to be successful. Future recoverable resources are estimated using an initial rate of 2.7 MBOPD and declining production to an abandonment rate of about 0.485 MBOPD in 2036.** This results in a TRR of **9,488 MBO**, and a TUR of **21,724 MBO**. **Based on production performance and estimated future recovery, the recover is only about 16.5% using an OOIP of 132 MMBO, indcating that the OOIP may be much lower.**

Water and gas forecasts are based on historical production. It is assumed all produced gas is used for lease operations.

[46] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Meltwater pool historical and future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-23. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

Meltwater pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.20**.

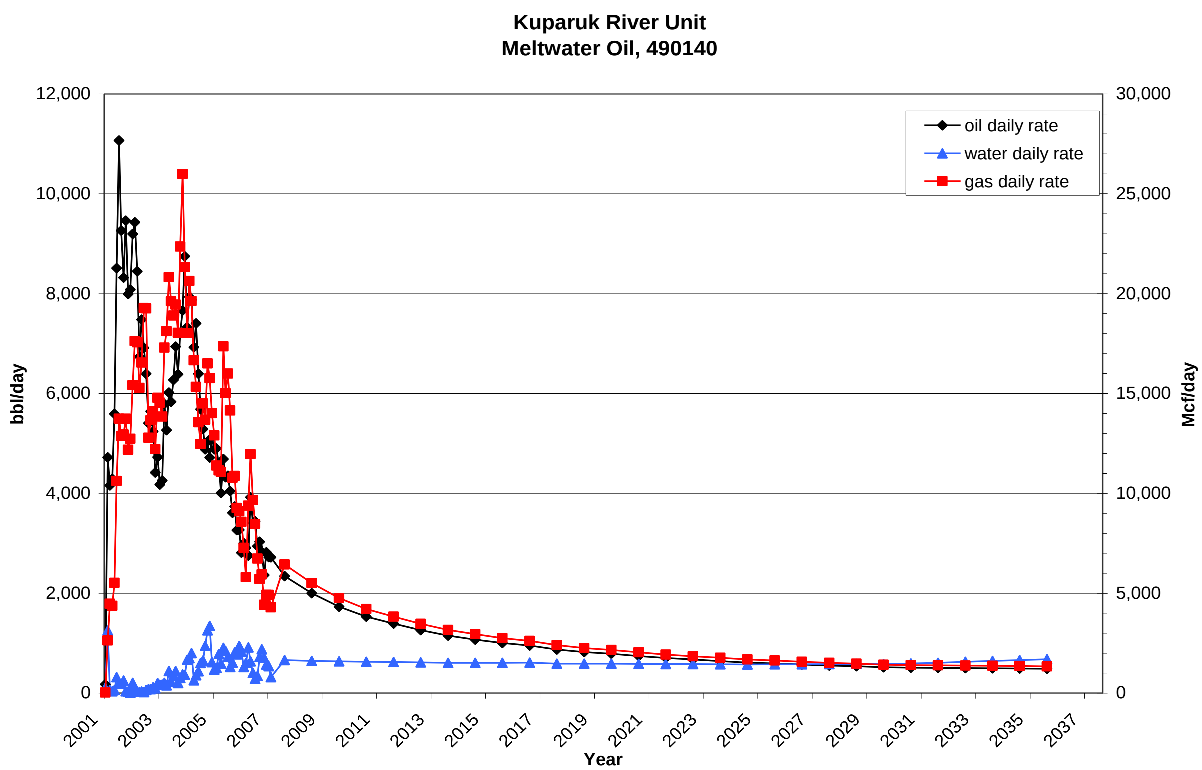

Figure 3-23. Kuparuk River Unit–Meltwater pool production history and forecasts.

Table 3.20. Meltwater pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	12,236	9,488	21,724
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	12,236	9,488	21,724
Gas Production (MMCF)	29,288	26,092	55,380
Gas Injection (est.) (MMCF)	33,798	30,168	63,966
Water Production (MB)	979	6,405	7,384

3.2.20 Kuparuk River Unit –Tabasco PA

The Tabasco pool was discovered in 1986 and production was started from the Tabasco Sandstone in 1998 (Table 2.5). **Engineering to determine the technically recoverable resources is described in this section.**

Tabasco pool is a KRU satellite development targeting an accumulation of between 48 and 131 MMBO OOIP of 16.5ºAPI oil. The estimated primary recovery is 5% and secondary recovery is from 16% to 25% (AOGCC, 1998). Using the above **range of** OOIP volumes results in a TUR between **10.1 MMBO (for 48 MMBO and 21% recovery)** and 39.0 MMBO **(for 131 MMBO and 30% recovery)**.

Produced fluids are processed at the KRU IPA facilities. The pool began producing in April 1998 and production peaked at about 8.0 MBOPD in May 1999. Production began declining immediately. A low rate of 1.28 MBOPD was reached in February 2002. Since then, production has fluctuated but **after drilling two horizontal wells** increased to an average of 5.3 MBOPD in the last six months of 2004. **Production dropped severely in the last half of 2007, but has returned to the previous level.**

Tabasco pool historical and **future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-24. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

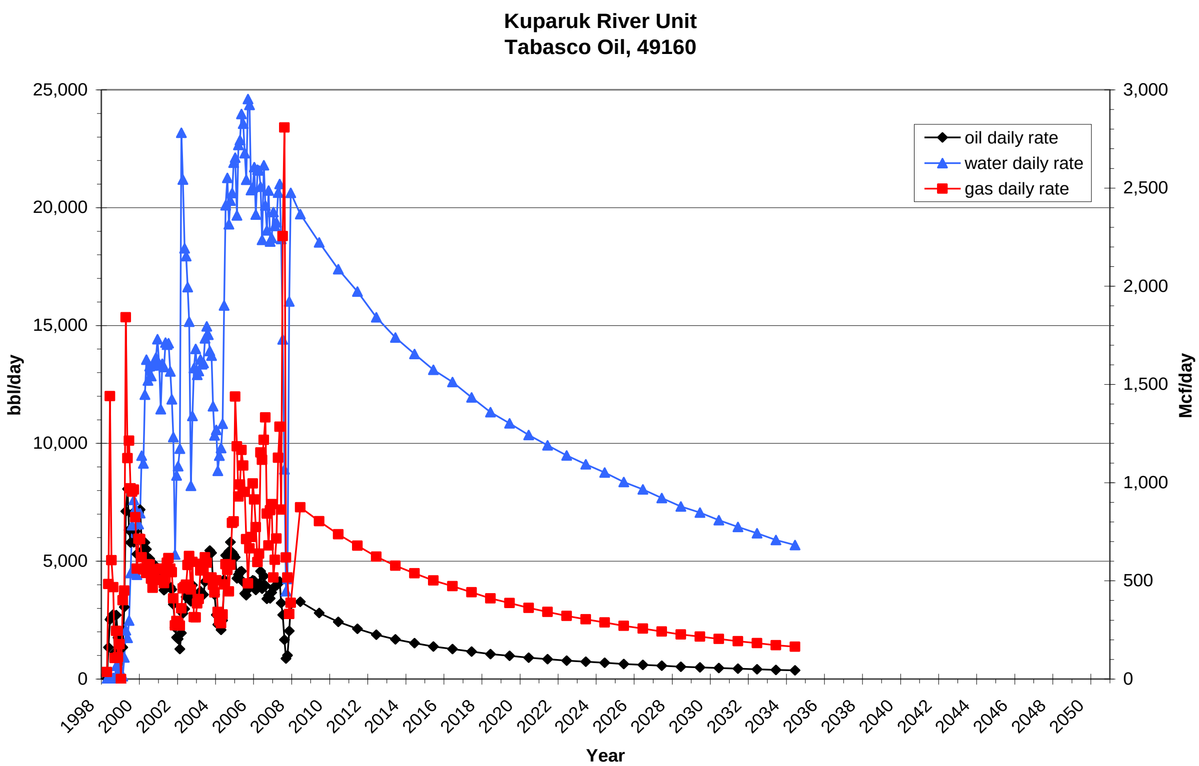

Figure 3-24. Kuparuk River Unit–Tabasco pool production history and forecasts.

Initially, 19 wells were planned for Tabasco, but after poor reservoir performance, this plan was **curtailed** after 12 wells were drilled. Currently, there are nine production wells and one water injection well. Water flooding began in June of 1998 and has continued to the present. Reservoir performance has suggested a weak waterflood response with strong water slumping due to gravity segregation. The water cut has been quite high since 2000, suggesting water recycling in the reservoir with poor vertical sweep. Future recovery plans could include **additional injection wells, lean gas injection and the use of polymers.**[47] No additional recoverable resources are included for these possible actions until proven successful.

Future TRR volumes are estimated using an initial rate of **about 3.5 MBOPD**, and declining **to an abandonment rate of 0.325 MBOPD**. This results in a TRR of **11,085 MBO** from the current recovery process and a TUR of about **24,829 MBO. Using a mid-range OOIP of 89,500 MBO results in a recovery factor of 27.7%**.

Gas and water forecasts are estimated using historical data. Gas production in excess of lease use is used off lease.

Tabasco pool historical oil, gas, and water **cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.21**.

Table 3.21. Tabasco pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	13,744	11,085	24,829
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	13,744	11,085	24,829
Gas Production (MMCF)	2,375	3,936	6,311
Gas Injection (est.) (MMCF)	0	0	0
Water Production (MB)	47,442	106,778	154,220

3.2.21 Kuparuk River Unit – Tarn PA

The Tarn pool was discovered in 1991 and production was started from the Seabee Formation in 1998 (Table 2.5). **Engineering analysis to determine the technically recoverable resources is described in this section.**

Tarn pool is a KRU satellite development targeting an assumed accumulation of **about 525 MMBO** of 37º API oil. **This estimate is based on production performance using the following recfovery factors.** Recovery factors are estimated at 10% primary with no recovery for secondary processes, and 21% incremental recovery for tertiary by MWAG process (AOGCC, 1998c).

[47] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Production is processed by the KRU IPA facilities. Production increased from about 8.8 MBOPD, to a peak rate of over 33,000 MBOPD in early 2002. Production remained above 30.0 MBOPD until July 2003 at which time the rate began to decline. **The production rate was 16.5 MBOPD over the last half of 2007.** The MWAG process has been successfully used since 2001 **supporting this low decline in producing rate**.

Tarn pool historical and **future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-25. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

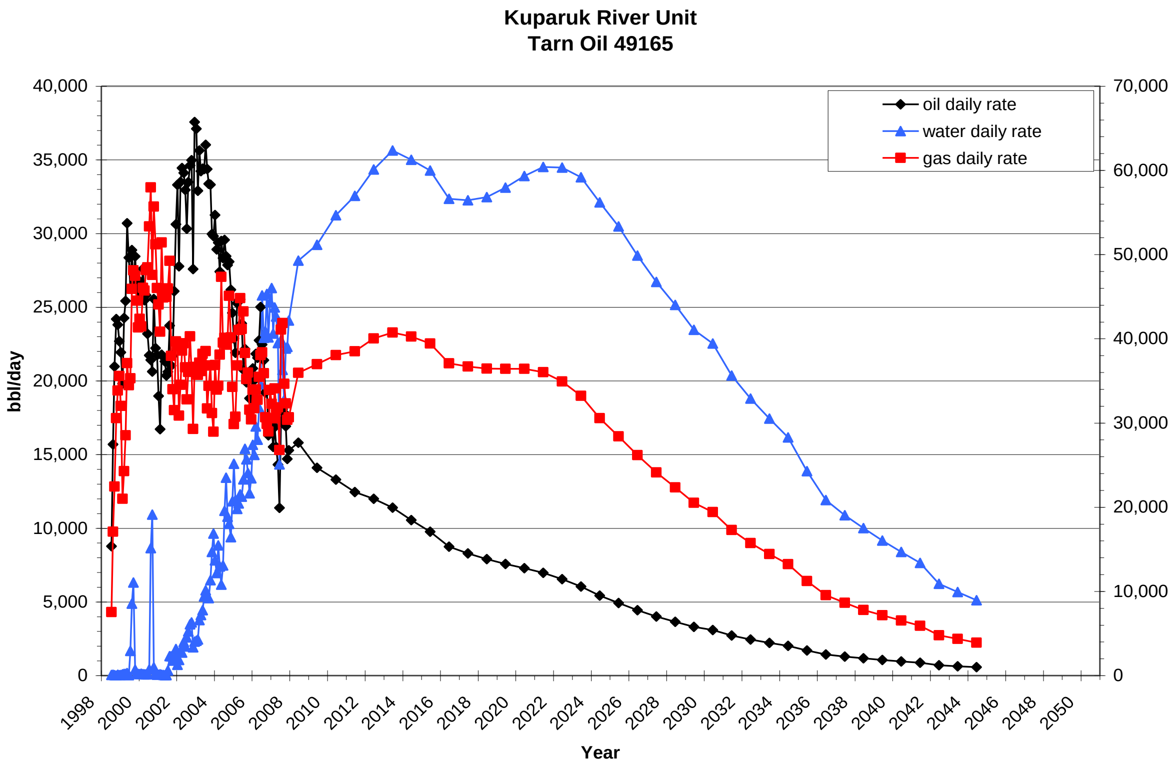

Figure 3-25. Kuparuk River Unit–Tarn pool production history and forecasts.

Recovery volumes to date come from a reservoir developed by four wells. The TRR for the current development is estimated using a decline of about 9% from a current rate if about 16,000 MBOPD to an abandonment rate of 0.570 MBOPD. This results in TRR of 59,701 MBO and a TUR of about 145,720 MBO.

Future operating plans include drilling up to 22 additional wells.[48] It is assumed 10 wells will be drilled in four stages over several years. The recovery estimate for the assumed 10 new wells (6 producers) was based on the per well recovery estimate from the current developed area. To be conservative the recovery estimate is reduced by 50% as the wells will be infill and periphery wells. The TRR for these wells is estimated using an

[48] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

average initial rate of .500 MBOPD in 2010 and gradually increasing to 2,600 MBOPD in 2021. Production was then declined to an abandonment rate of 0.57 MBOPD in 2044, and results in a TRR of 16,000 MBO.

This results in a **total** TRR of **75,701 MBO** and a total TUR of **161,720 MBO**. **Using a recovery of 31% indicates an OOIP of 521 MMBO, slightly higher than the range of 350 to 500 MMBO.**

Forecast gas volumes are based on historical performance of the oil recovery versus **GOR**. Water production is forecasted using historical water cut versus oil recovery. It is assumed all gas is used for lease operations and in the EOR process.

Tarn **pool** historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.22**.

Table 3.22. Tarn pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	86,019	75,701	161,720
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	86,019	75,701	161,720
Gas Production (MMCF)	129,174	328,261	457,435
Gas Injection (est.) (MMCF)	127,017	333,435	460,452
Water Production (MB)	27,846	321,648	349,494

3.2.22 Kuparuk River Unit – West Sak PA

The West Sak pool was discovered in **1969 (Table 2.5)** and production from the Prince Creek Formation began in 1983 (Thomas et al., 1993). **Engineering analysis to determine the technically recoverable resources is described in this section.**

The West Sak PA was formed in the early 1980s to test the West Sak accumulation believed to contain between 15 and 20 BBO[49] with variable oil gravity from 10 to 22ºAPI (AOGCC, 1997). **Recovery is expected to occur from only a portion of the total accumulation, referred to as the core development area.** The core development area is assumed to contain 2 BBO **of which only 60% (1.2 BBO) is considered to be economical to develop**. **With the advance of technology of horizontal drilling and proven recovery enhancement all of this OOIP is assumed to be economically developable. The core development area consists of (1) the initial development area and an area assumed to be in a continouos expansion program, and (2) an area considered to be under evaluation.** Under current technology **recovery from the initial development area and from the expansion area**

[49] This volume is combined West Sak and Schrader Bluff

are estimated to be primary recovery 8%, secondary 10%, and WAG at 4% for a total recovery of 22% OOIP (AJC, 2004).

Production is processed by the KRU IPA facilities. Initial production beginning in June 1983 and ending in December 1986 was a test program for the West Sak. Production using the earlier technology (vertical and hot water pilot flood) was uneconomical (Thomas et al., 1993). Current technology including the use of horizontal and multilateral wells has improved reservoir performance to justify further development of the core area (AJC, 2004). Production was restarted in mid-1998. The current development **consists of 36 active producers and 35 active water injection wells**.

West Sak pool historical oil, gas, and water **productions** after 1997 **and future technically recoverable oil, gas and water productions versus time for the initial development area and the expansion area are presented graphically in Figure 3-26. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

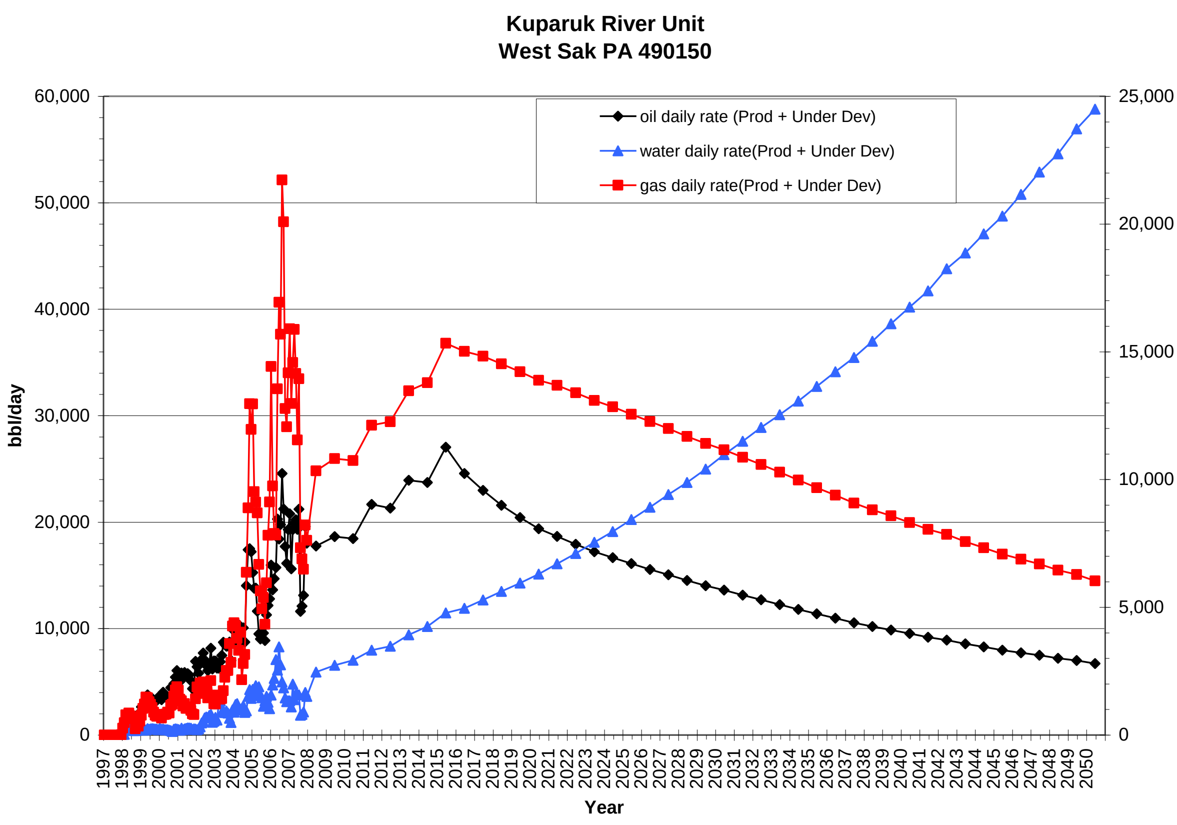

Figure 3-26. Kuparuk River Unit–West Sak pool production history and forecasts.

The initial development area containing an estimated **555 MMBO OOIP had peak production of over 20 MBOPD during August 2007**. **The** TRR **for the initial producing area is estimated using an initial production at 1/1/2008 of about 17,000 MBOPD and declining to an abandonment rate of about 2,300 MBOPD. This yields a TRR of 89,363 MBO and a TUR of 121,646 MBO**.

Based on success of the current development, additional development is expected to be expanded to areas outside the initial development area. The expansion could include the drilling of 53 additional wells through 2011.[50] It is assumed the expansion area contains about 645 MMBO OOIP and recovers about 22% of OOIP. The expansion area is assumed to have a continuous development program with initial production occurring in 2009 at 2,000 MBOPD. The assumed development program results in a gradual increase in producing rate to about 27,000 MBOPD in 2015. Production will remain above 20,000 MBOPD from 2011 through 2019 before beginning to decline, to an abandonment rate of 6,700 MBOPD in 2050. This results in a TRR of 141,372 MBO.

The total TRR for the initial producing area plus the expansion area under development is 230,735 MBO and a TUR of 263,018 MBO.

Historical water cut versus cumulative and GOR versus cumulative data for the initial development area are used to forecast future produced volumes. The solution GOR is very low at 200 CF/BBL; however, with gas injection for the WAG process, an increase will result throughout the productive life. It is assumed the GOR will gradually increase from an average of **200 CF/BBL** in 2004 to **900 CF/BBL** at abandonment in all development areas. The water cut of the initial development area is about 0.2 at a recovery of 23% of TUR. It is assumed the water cut will gradually increase until it reaches 0.9 at abandonment. All produced gas will be used **for lease operations**. The new areas to be developed will start at a water cut of 0.1 and increase to 0.9 at abandonment. The gas production forecast is made using an initial GOR of 200 CF/BBL that gradually increases to **900 CF/BBL** at abandonment.

West Sak **pool** historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.23**.

Table 3.23. West Sak pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	32,283	230,735	263,018
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	32,283	230,735	263,018
Gas Production (MMCF)	17,211	168,341	185,552
Gas Injection (est.) (MMCF)	447	0	447
Water Production (MB)	9,540	430,872	440,412

[50] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

<u>Projects Under Evaluation</u>: A thinner net pay portion of the core development area containing about 800 MMBOIP is considered to be under evaluation. Development of this area will depend on continued success in drilling and recovery processes in the other areas currently under development. If successful, the development of this area would increase TRR by about 167.8 MMBO. This potential reserve is discussed further in Kuparuk River Unit – West Sak – Under Evaluation**.**

3.2.23 Milne Point Unit – Kuparuk River IPA

The Kuparuk River pool of the Milne Point Unit (MPU) was discovered in 1969 and production started in 1985 from the Kuparuk River sandstone (Table 2.5). Continuous production commenced in 1989. **Engineering analysis to determine the technically recoverable resources is described in this section.**

The MPU Kuparuk River pool is a development targeting an estimated accumulation of 525 MMBO OOIP of 22°API oil. Estimated primary and secondary recovery is 20% each with an additional 6 to 8% from EOR (AOGCC, 2002b). Based on production performance, **the forecasted** total **TUR of 385,986 MBO**. **This is a strong indication the OOIP estimate is low. Using a 46% recovery factor, a more reasonable OOIP volume is about 850 MMBO, which is assumed for this analysis.**

Production is processed by the MPU IPA facilities. Production averaged 12.7 MBOPD from November 1985 through January 1987 at which time production was shut-in. Production was restarted April 1989 with production rising from 10 MBOPD to 50 MBOPD by August 1996. Production was sustained above **40 MBOPD through December 2001** before starting on decline. Future activities will consist of **new infill or edge wells,** redrilled wells, well workovers, injection conversions and an EOR process. It is anticipated that NGLs will be purchased from PBU and used with NGL production from the Milne Point Unit for WAG process. **Other EOR techniques could also be used.**[51]

MPU Kuparuk pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-27. The individual oil production forecast is tabulated in Appendix A, Table A.1.

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[51] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

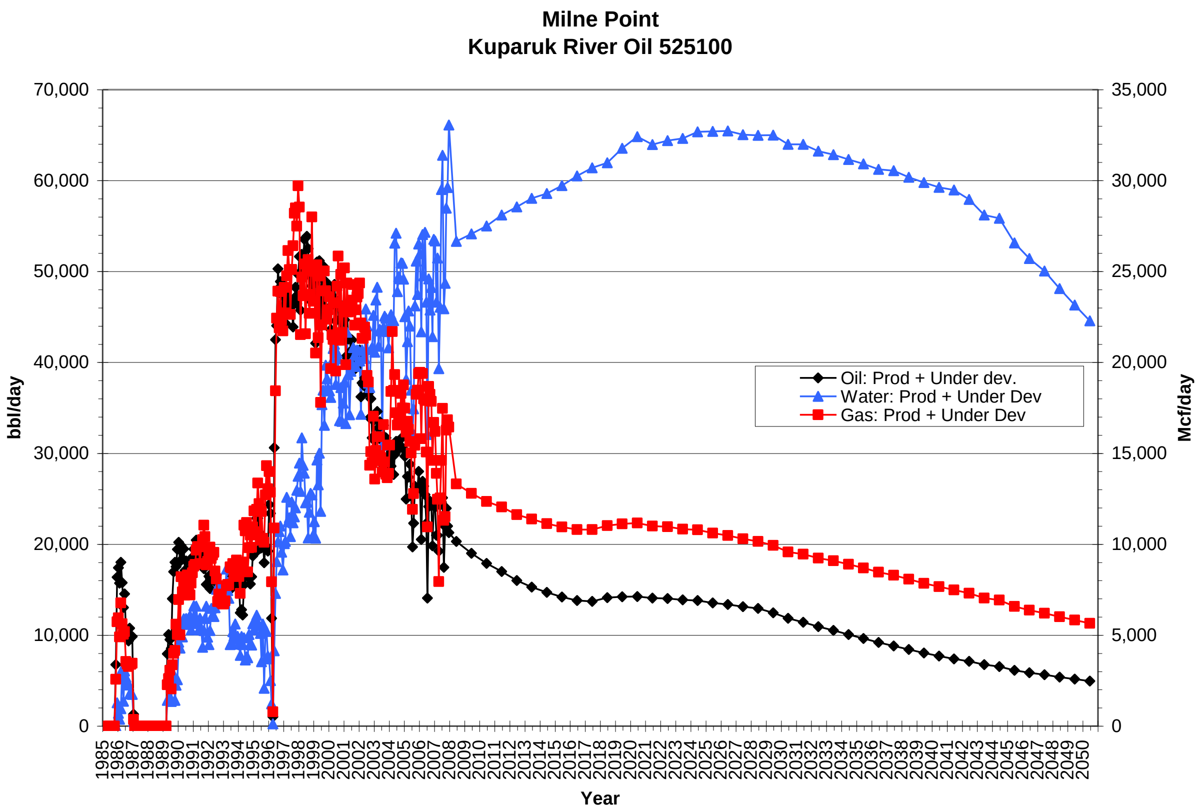

Figure 3-27. Milne Point Unit–Kuparuk pool production history and forecasts.

The pool has been on decline since late 1999. **A decline of less than 10% is indicated. The TRR for the current producing development is estimated using an initial rate of 21 MBOPD and declining production to an abandonment rate of 3.2 MBOPD in 2050. This results in a TRR of 137,440 MBO, and results in a TUR of about 343,826 MBO for the current producing development.**

Continued drilling workovers, and results of the EOR processes is expected to increase recovery. The recovery factor is assumed to be about 5% (slightly less than the 6 to 8%) of the indicated OOIP of 850 MMBO. Recovery of these resources is assumed to begin in 2009 at 0.10 MBOPD and increase gradually to a peak rate of 5.000 MBOPD in 2020 before beginning to decline to an abandonment rate of 1.7 MBOPD in 2050. This results in a TRR and TUR of 42,160 MBO for the additional activities.

This results in a total TRR of 179,600 MBO and a total TUR of 385,986 MBO, for a total recovery factor of 45.4%.

The water and gas forecast **are based on** the historical water cut and **GOR** trends. It is assumed that all gas will be used for lease operations or in an EOR project.

MPU Kuparuk pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.24**.

Table 3.24. Milne Point Unit–Kuparuk pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	206,386	179,600	385,986
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	206,386	179,600	385,986
Gas Production (MMCF)	108,652	147,867	256,519
Gas Injection (est.) (MMCF)	91,626	136,840	228,466
Water Production (MB)	189,767	928,129	1,117,896

3.2.24 Milne Point Unit – Sag River PA

The Sag River pool of the MPU was discovered in 1969 and production started in 1995 from the Sag River and Ivishak Formations (Table 2.5). **Engineering analysis to determine the technically recoverable resources is described in this section.**

The Sag River pool is a development targeting an accumulation of 62 MMBO OOIP. Estimated primary recovery was 15% and an additional 23% by water/gas injection (AOGCC, 1998b). Based on performance to date **and operator's curtailment of development plans**, these recovery factor estimates **appear to be** high. Production performance is used to estimate the recoverable resources.

Production is processed by the MPU IPA facilities. The original development plan included 16 producers and 9 injectors. After four producers were drilled to test the accumulation, development plans were curtailed, apparently due to poor results. Currently there is one producer operating part time plus one injection well for both water and gas. The project recovered only **69.3 MBO** during **2007** while producing for only about **60% of the time during** the year. Historical oil, gas, and water production are presented in Figure 3-28.

Sag River pool historical oil, gas, and water productions versus time are shown graphically in Figure 3-28.

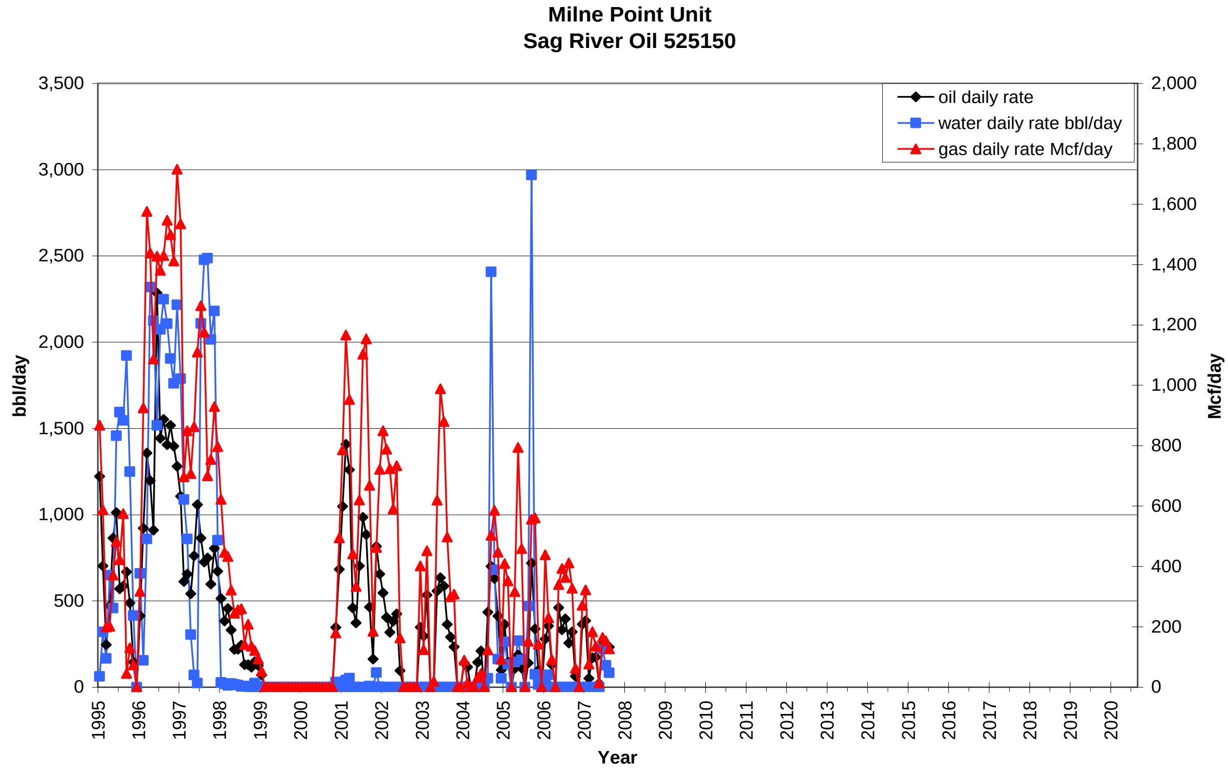

Figure 3-28. Milne Point Unit–Sag River pool production history

The operator is **continuing** evaluating performance, and has no immediate plans for further development.[52] Current performance does not justify assigning any TRR to this development. A future estimate of TRR may be required if the operator is successful in improving performance.

Sag River pool historical oil, gas, and water cumulative **productions are** presented in Table 3.25.

Table 3.25. Sag River pool production statistics as of 1/1/ 2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	1,849	0	1,849
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	1,849	0	1,849
Gas Production (MMCF)	1,884	0	1,884
Gas Injection (est.) (MMCF)	249	0	249
Water Production (MB)	1,668	0	1,668

[52] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

3.2.25 Schrader Bluff PA

The Schrader Bluff pool of the Milne Point Unit was discovered in 1969 and the production started in 1991 from the Schrader Bluff Formation. **Engineering analysis to determine the technically recoverable resource is described in this section.**

The Schrader Bluff PA was formed in the early 1990s to test the Schrader Bluff accumulation believed to contain between 15 and 20 BBO (AOGCC, 1997) of 17°API oil. This development targets an estimated accumulation of between 1.25 and 2 BBO OOIP in the main core area. **It is assumed that only two-thirds of a total OOIP of 2 BBO (1.334 BBO) will be economical to develop.** Primary and secondary recovery is estimated at about 11% each for a total of about 22% (AOGCC, 2002c). This gives an assumed TUR of about 293 MMBO, which is used as a guide in estimating the TRR for the project.

The initial producing area had **49** producers and **42** injection wells at year end **2007**. It is assumed additional development **will be a continuing program to complete the development of the core area**. **The wells required are assumed to be drilled from the existing** E, H, and S pads and from **one** new pad to be constructed. The initial development area is assumed to contain **about 625 MMBO** OOIP. **The remaining areas are assumed to contain the balance of the OOIP of about 710 MMBO**, which is assumed to be equally divided between the **five** areas to be developed. **The main core area is assumed to contain 1,334 MMBO OOIP for this analysis based on production performance to date and forcasted future recoverable resources.**

The production from the initial developed area has increased from about 3.0 MBOPD in 1992 to about **a peak of 21.0 MBOPD for the year** 2004. **Production has decline to about 13.0 MBOPD in December 2006.** Production is processed by the MPU IPA facilities.

The technically recoverable oil and gas for the current producing wells is estimated using an initial rate of 13.0 MBOPD. It is assumed production of 20.5 MBOPD will be sustained through 2006, at which time and declining production to a final rate of 2.2 MBOPD. This results in a TRR of about **85,034 MBO** and a TUR of **138,338 MBO**.

Schrader Bluff pool historical and **future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-29. The individual oil production forecast is tabulated in Appendix A, Table A.1.**

Gas and water forecasts are developed based on the historical data. It is assumed that all gas production will be used for lease operations and potentially in an EOR process.

It is assumed the balance of the core area, or about 710 MMBO OOIP, will be a continuation of the current program with future development contingent on continued

acceptable results (ADNR, 2007)[53]. For simplicity in forecasting future oil TRR and gas and water, the future development was assumed to occur in five developmental phases with initial wells to be drilled in 2008 and the last wells placed on production in 2023. Combined production rates for the phases commenced at 0.5 MBOPD in 2008 and gradually increases to a little over 15.0 MBOPD in 2019. It is assumed production will average between 15.0 and 16.0 MBOPD through December 2028 at which production begins to decline. Using a final rate of 3.5 MBOPD in 2050 results in a TRR of 157,066 MBO.

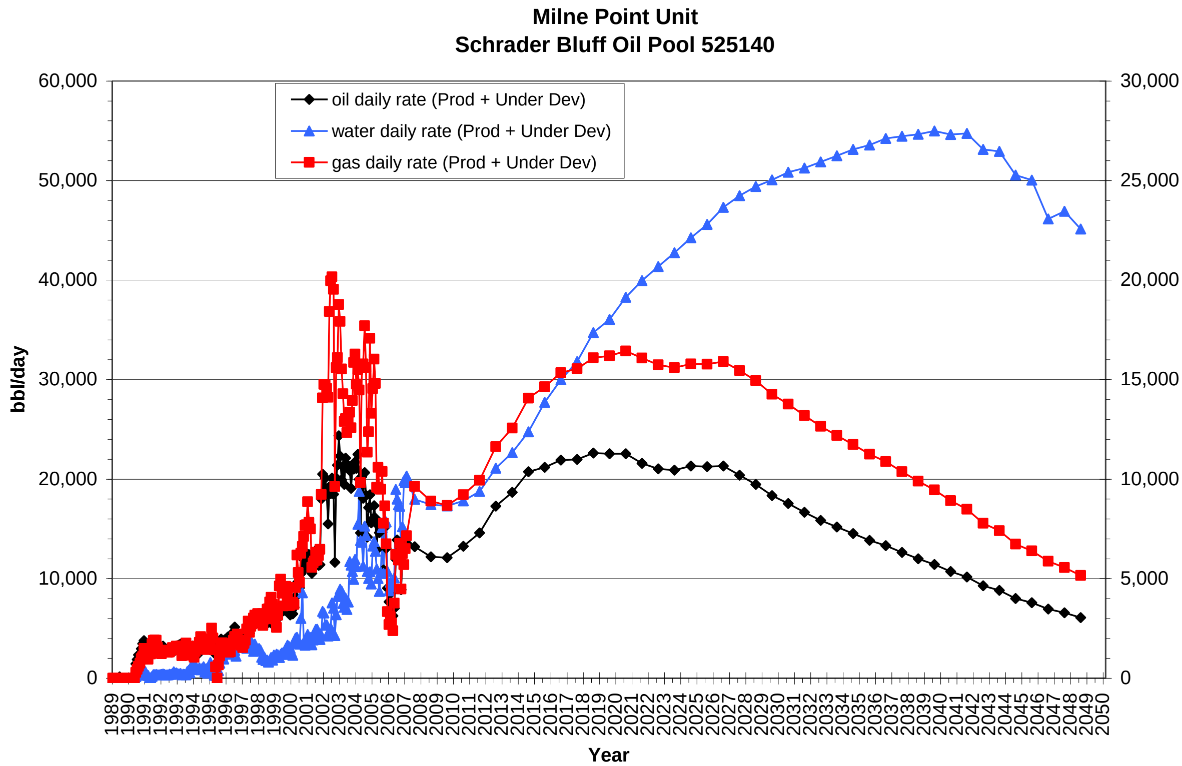

Figure 3-29. Milne Point Unit–Schrader Bluff pool production history and forecasts

The total TRR for the Schrader Bluff pool is 242,100 MBO and a total TUR of 295,404 MBO. This is a recovery of 22.2% of the assumed 1,334 MMBO OOIP in the main core area.

Schrader Bluff pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008** are presented in Table 3.26.

[53] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Table 3.26. Milne Point Unit–Schrader Bluff pool production statistics as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	53,304	242,100	295,404
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	53,304	242,100	295,404
Gas Production (MMCF)	34,093	182,842	216,935
Gas Injection (est.) (MMCF)	125	125	125
Water Production (MB)	29,544	655,206	684,750

3.2.26 Colville River Unit – Alpine Field IPA

The Alpine pool of the Colville River Unit (CRU) was discovered in 1994 and production started in 2000 from the Alpine sandstone (Table 2.5). **Engineering analysis to determine the technically recoverable resources is described in this section.**

The Alpine pool is a development targeting and estimated accumulation of between 650 and 1,100 MMBO OOIP (AOGCC, 1999; ADNR, 2002b). This development was significant because of its size, light 40ºAPI oil, and that it expanded development to the west of the KRU by about 20 miles. Recovery estimates are for primary recovery between 10 and 15% with EOR adding between 45 and 50% for a total range of 55 to 65% (AOGCC, 2002b). **The high reservoir quality and initial high production response support these higher recovery factors. Production performance and estimated future recovery and an average OOIP of 875 MMBO indicates a recovery factor of about 59%.**

Production started November 2000 at an initial rate of 17.5 MBOPD and increased to a peak annual average of **120.0 MBOPD during 2005**. **Cumulative recoveries to 1/1/2008 are 260,116 MBO, 12,672 MBW and 306,132 MMCFG.**

Gas and water forecasts are developed based on the historical data. It is assumed that all gas **production will be** used for lease operations **and potentially in an** EOR process.

Alpine pool historical and **future technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-30. The individual oil production forecast is tabulated in Appendix A, Table A.1**.

All wells planned to develop the Alpine pool have been drilled as of November 2005. A total of 103 wells have been drilled (49 producers and 54 injectors) to complete the development of the majority of this reservoir. It is assumed there will be new wells, redrills, and workovers in the future to recover the maximum resources and maintain a high production rate.

An estimate of **1,000 MMBO OOIP** is used for this study, implying a recovery of over 500 MMBO. Based on production performance that estimate appears reasonable at this time.

After reaching a peak rate of about 130.0 MBOPD in December 2005, the producing rate has declined to about 83.0 MBOPD in December 2007. This decline history is used to forecast future recovery and results in a TRR of **259,243 MBO at a final rate of about 2.9 MBO in 2050. This results in** a TUR of about **519,359 MBO**.

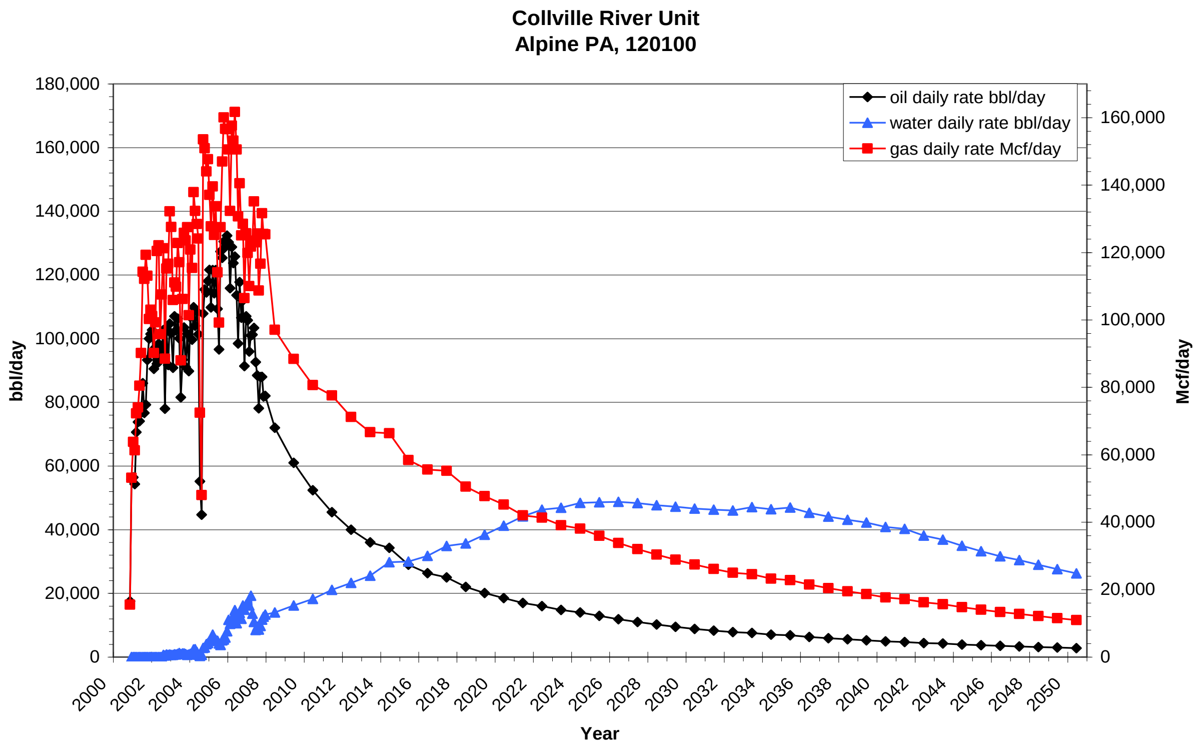

Figure 3-30. Colville River Unit–Alpine pool historical production and forecasts.

Historical gas and water production are used to forecast future gas and water recoveries. It is assumed the GOR will increase from a current 1,250 to **3,750 cubic feet per barrel** (CFPB) at abandonment. Water production volumes are increasing. The water cut at year end **2007 was 0.12 at a recovery of about 50%** of the TUR. The water cut is expected to increase to a water cut of **0.90** at depletion. All gas is used for lease operations or reinjected for the EOR process. **At 1/1/2008, about 88% of produced gas had been reinjected.**

Alpine pool historical oil, gas, and water cumulative production **and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.27**.

Table 3.27. Colville River Unit–Alpine pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	260,116	259,243	519,359
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	260,116	259,243	519,359
Gas Production (MMCF)	306,132	572,063	878,195
Gas Injection (est.) (MMCF)	270,881	514,869	785,750
Water Production (MB)	12,672	587,353	600,025

Projects Under Evaluation: A study is being conducted on the potential of drilling into the undeveloped Alpine reservoir adjacent to Nanuq CD4 development area.[54] Due to the uncertainty of this effort, no recoverable oil and gas volumes are assigned for TUR and TRR in this section. If successful, a TRR of about 40,000 MBO is possible. These potential recoverable volumes are discussed in Section 3.4.1.5.

3.2.27 Colville River Unit – Fiord Pool – CD3

The Fiord pool was discovered in 1992 and is an assumed accumulation of about 150 MMBO OOIP, in the Kuparuk River "C" and Nechelik sandstones. The Fiord pool is a satellite to the Alpine PA and about 5 miles north of the Alpine pool (PN, 2004b). Engineering analysis to determine the technically recoverable resources is described in this section.

The Fiord pool satellite was reported to contain 50 MMBO of TUR (PN, 2002), (Table 2.5). However, production performance to date suggests that estimate is low. Development began during 2005 and continuous production began in August 2006. A total of 17 wells are expected to completely develop both the Nechelek (12 wells) and the Kuparuk (5 wells).[55] Comingled production is being processed by the Alpine PA facilities and may be limited by the Alpine facilities operating capacity. MWAG was initiated in August 2007.

When development is complete, production is assumed to be about 20 MBOPD by late 2008. Production will be level for two years before beginning to decline at about 15% per year to a final abandonment rate of about 0.3 MBOPD in 2050. This results in a TRR of about 88,054 MBO, and a TUR of 95,418 MBO. This suggests the OOIP volume above is conservative. For this analysis, it is assumed that the Fiord pool contains about 150 MMBO OOIP.

[54] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.
[55] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Gas and water production volumes are estimated using the GOR and water cut versus recovery relationships from the Milne Point Kuparuk PA as a pattern. It is assumed all gas will be used for lease operations and the EOR process.

Fiord pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-31. The individual oil production forecast is tabulated in Appendix A, Table A.1.

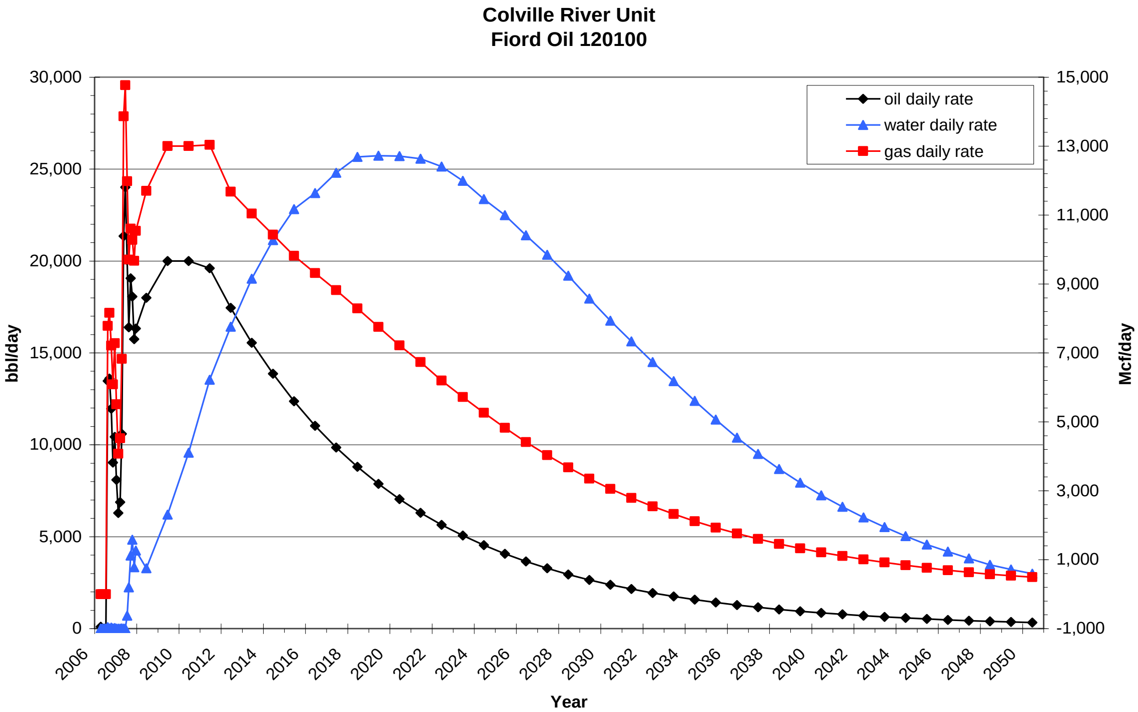

Figure 3-31. Colville River Unit–Fiord pool production forecasts.

Colville River Unit Fiord pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.28.

Table 3.28. Colville River Unit–Fiord pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	7,364	88,054	95,418
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	7,364	88,054	95,418
Gas Production (MMCF)	4,531	76,253	80,784
Gas Injection (est.) (MMCF)	1,149	68,628	69,777
Water Production (MB)	594	222,865	223,459

3.2.28 Colville River Unit – Nanuq Kuparuk Pool – CD4

The Nanuq Kuparuk pool was discovered in 2000 and has an assumed OOIP of about 120 MMBO OOIP. The Nanuq field is a satellite to the Alpine PA and about 4 miles south of the Alpine pool (ADNR, 2002b). Engineering analysis to determine the technically recoverable oil and gas resources is described in this section.

Development began during the winter of 2006 and will continue for several years.[56] Development drilling has totaled 9 wells to 1/1/2008 and will total 20 wells to complete development. Production is being processed by the Alpine PA facilities. EOR will be utilized.

Production began in November 2006 and increased to 19 MBOPD by year-end 2007. Cumulative production to 1/1/2008 is 6,753 MBO. Production is assumed to begin declining immediately to an abandonment rate of about 0.18MBOPD. This results in a TRR of about 36,296 MBO, and a TUR of about 43,049 MBO, or about 36% of the OOIP.

Gas and water production volumes are estimated using the GOR and water cut versus recovery relationships from the Kuparuk River Unit as a guide. It is assumed all gas will be used for lease operations and the EOR process.

Nanuq Kuparuk pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-32. The individual oil production forecast is tabulated in Appendix A, Table A.1.

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[56] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

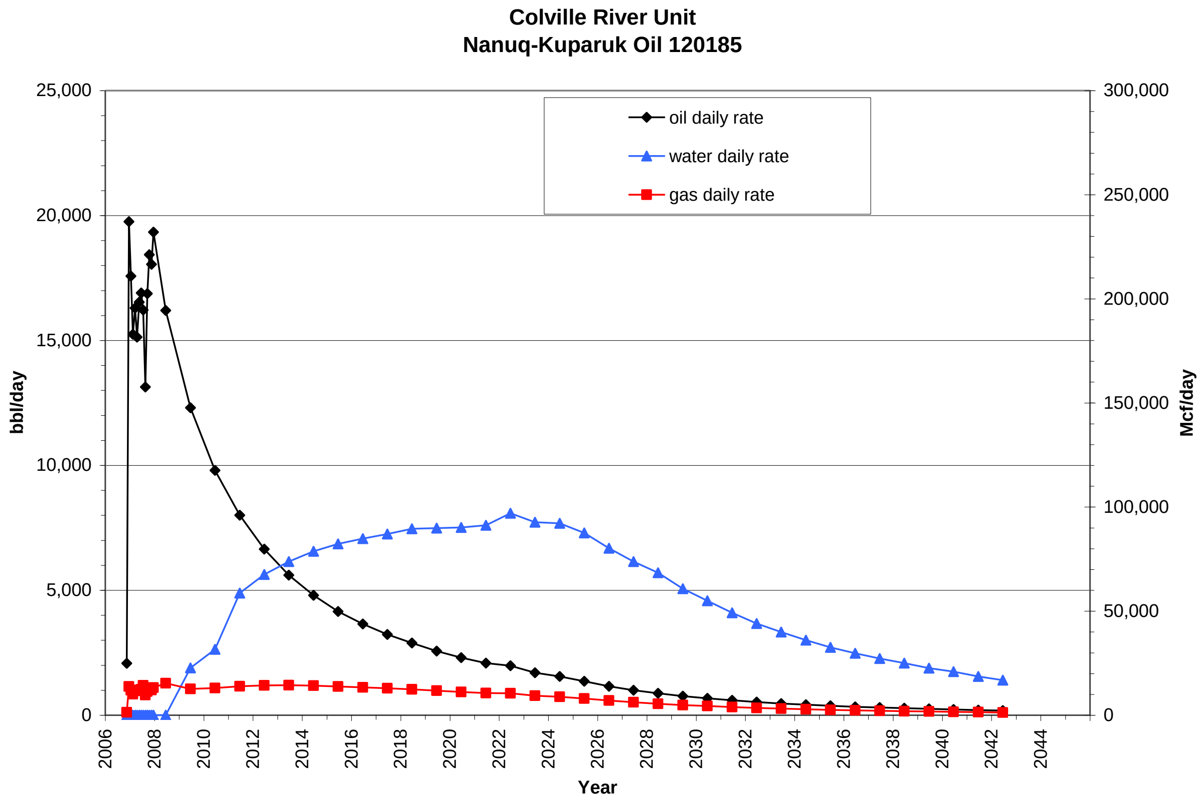

Figure 3-32. Colville River Unit–Nanuq Kuparuk pool production forecasts.

Colville River Unit Nanuq Kuparuk pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.29.

Table 3.29. Colville River Unit–Nanuq Kuparuk pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	6,753	36,296	43,049
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	6,753	36,296	43,049
Gas Production (MMCF)	4,818	100,982	105,800
Gas Injection (est.) (MMCF)	1,685	75,737	77,422
Water Production (MB)	1	61,378	61,379

<u>Projects Under Evaluation</u>: Implementation of EOR (MWAG) is necessary in the Nanuq CD4 Kuparuk pool. It is assumed the first miscible injectant began in June 2007. Because results are not yet apparent, this potential under-evaluation resource of about 4,850 MBO is described in Section 3.4.1.6. This estimate is the combined total for the Kuparuk and Nanuq reservoirs.

3.2.29 Colville River Unit – Nanuq Nanuq Sand Pool – CD4

The Nanuq Nanuq Sand pool was discovered in 2000 and has an assumed OOIP of about 30 MMBO OOIP. The Nanuq Sand pool is a satellite to the Alpine PA and about 4 miles south of the Alpine pool (ADNR, 2002b). Engineering analysis to determine the technically recoverable oil and gas resources is described in this section.

Development began in 2006 with four wells completed to date. The pool was to have a potential total of 20 wells.[57] However, performance to date does not appear to justify more drilling. Production is being processed by the Alpine PA facilities. EOR will be utilized if justified.

Production began in December 2006 and increased to about 0.7 MBOPD in December 2007. Cumulative production to 1/1/2008 is 162 MBO. Production is assumed to begin declining immediately to an abandonment rate of 0.1 MBOPD by 2033. This results in a TRR of about 11,078 MBO, and a TUR of about 11,240 MBO. This TUR gives a recovery factor of 37.5% primary recover, indicating that additional drilling may not be justifiable.

Gas and water production volumes are estimated using the GOR and water cut versus recovery relationships from the Kuparuk River Unit as a guide. It is assumed all gas will be used for lease operations and the possible EOR process.

Nanuq Nanuq Sand pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-33. The individual oil production forecast is tabulated in Appendix A, Table A.1.

[57] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

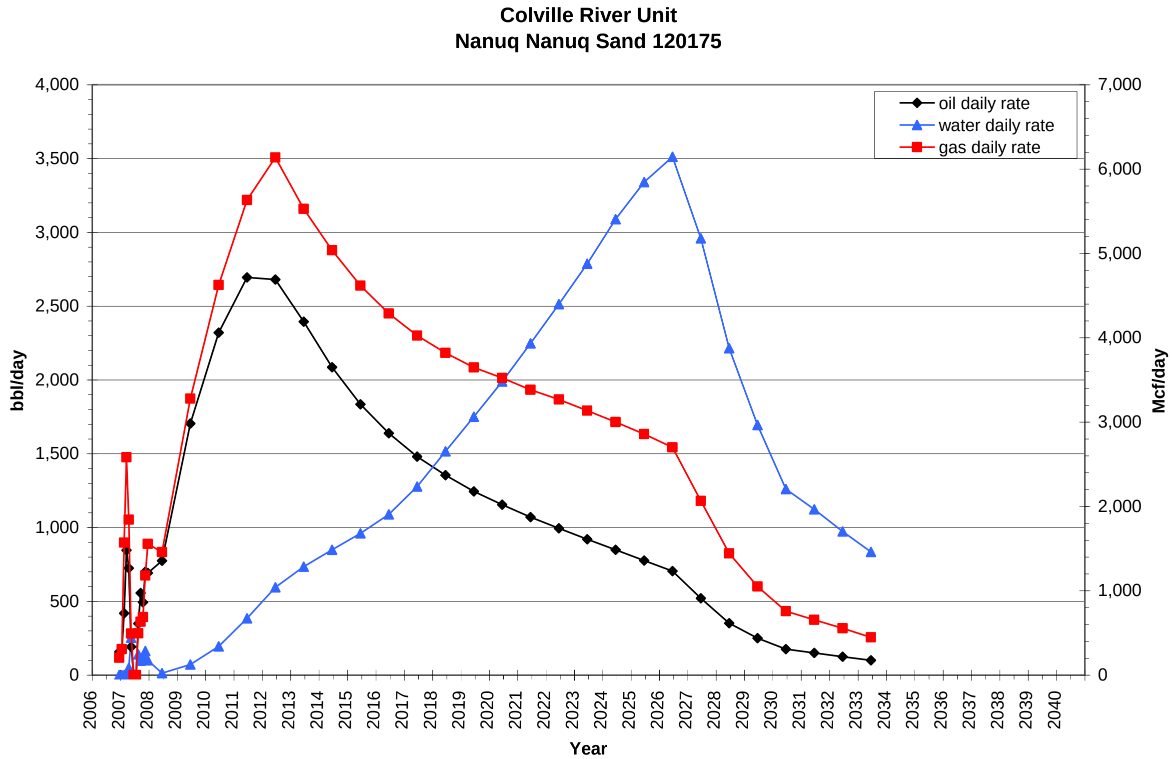

Figure 3-33. Colville River Unit–Nanuq Nanuq Sand pool production forecasts.

Colville River Unit Nanuq Nanuq Sand pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.30.

Table 3.30. Colville River Unit–Nanuq Nanuq Sand pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	162	11,078	11,240
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	162	11,078	11,240
Gas Production (MMCF)	353	29,541	29,894
Gas Injection (est.) (MMCF)	0	0	0
Water Production (MB)	28	14,587	14,615

<u>Projects Under Evaluation</u>: Continuation of the EOR project is under evaluation for the Nanuq CD4 Nanuq pool. Initial injection began in 2007; however, it is too soon for results to be apparent. If successful, this project could add an estimated 4,850 MBO to the ultimate recovery. This project is discussed further in Section 3.4.1.6.

3.2.30 Colville River Unit – Alpine Qannik Pool – CD2

The Alpine Qannik pool was discovered in 2006 and is an assumed accumulation of about 79 MMBO OOIP in the Qannik sandstone. The pool is a satellite to the CRU Alpine PA and is located adjacent to the Alpine PA CD2 drillsite (PN, 2005; PN, 2008k). Engineering analysis to determine the technically recoverable oil and gas resources is described in this section.

The Qannik well was drilled and completed in 2006 and test produced for three months beginning in June 2006. A total of 54.8 MBO was recovered. Pool development will utilize six horizontal producers and three horizontal injectors. The produced liquids are being processed by the Alpine PA facilities and a combination waterflood/gas cap drive process will be employed.[58]

Continuous production began in July 2008 and expected to reach a rate of 4,000 BOPD during 2009. Production is assumed to increase gradually to 2011 and will average 4,200 BOPD for that year. Production will decline at 7.5% to an abandonment rate of about 324 BOPD in 2044. This results in a TRR of 21,231 MBO, and a TUR of 21,286 MBO, indicating a combined primary and secondary recovery factor of about 27%.

Gas and water production volumes are estimated using the GOR and water cut versus recovery relationships from the Milne Point Kuparuk Formation. It is assumed all gas will be used for lease operations and the recovery process.

Qannik pool historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-34. The individual oil production forecast is tabulated in Appendix A, Table A.1.

[58] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

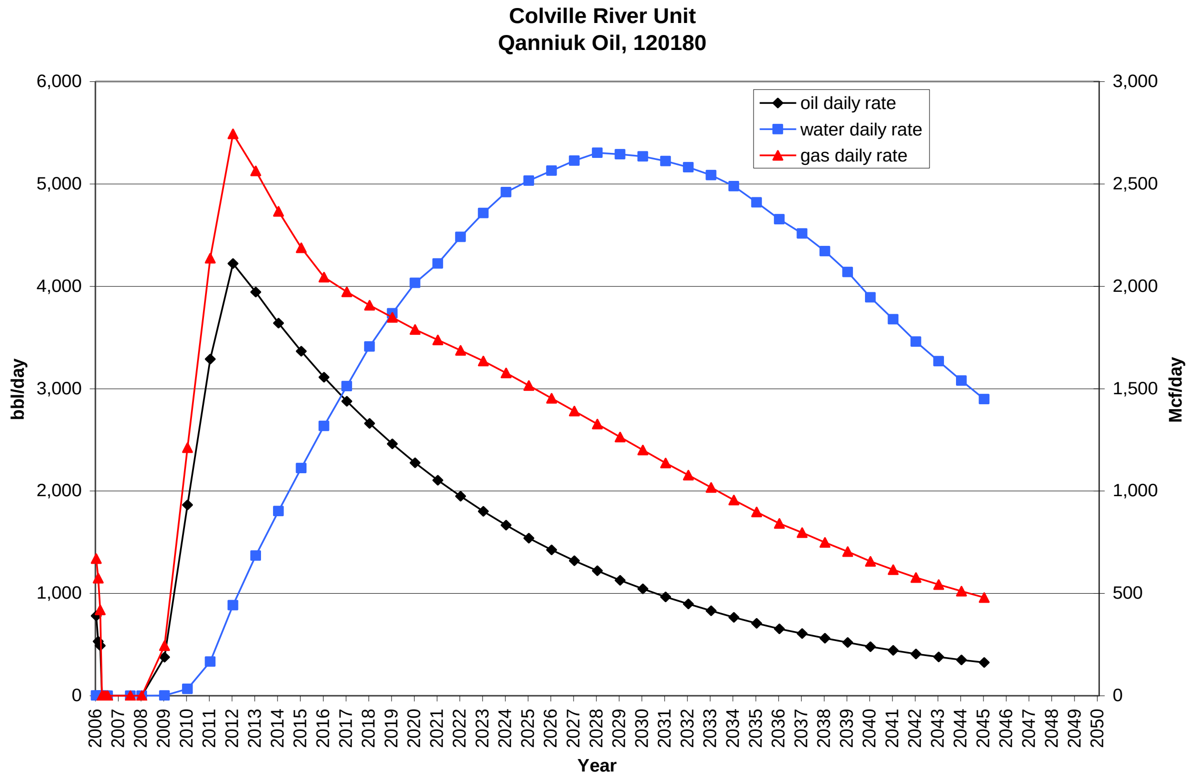

Figure 3-34. Colville River Unit–Qannik pool production forecasts.

Colville River Unit Qannik pool historical oil, gas, and water cumulative production and forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.31.

Table 3.31. Colville River Unit–Qannik pool production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	55	21,231	21,286
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	55	21,231	21,286
Gas Production (MMCF)	51	18,014	18,065
Gas Injection (est.) (MMCF)	0	16,200	16,200
Water Production (MB)	0	49,745	49,745

3.2.31 Oooguruk Unit

The Oooguruk Unit, an assumed accumulation of 265 MMBO OOIP in the Nuiqsut and Kuparuk Sands, was discovered in 2003. It is located offshore northwest of the KRU (PN, 2005f). One report indicates as much as 90 MMBO may be recovered (PN, 2008l). Recoverable oil and gas and recovery rates are estimated using published reports.

The accumulation is being developed using one on-shore pad and one off-shore pad. Initial development began in December 2007. A total of 33 horizontal wells will be used in this project, with 18 producers and 15 injectors. It is assumed two producers and two injectors will be drilled in the Kuparak pool. Drilling is expected to be completed by year-end 2010. Initial production began in June 2008. A peak rate of between 15 and 20 MBOPD is anticipated. Water injection will be used for pressure maintenance and secondary recovery. If sufficient gas volumes can be obtained, a WAG process will be utilized. The production life is expected to be about 40 years. Produced fluids will be processed through the KRU IPA (PN, 2006c).[59]

Although the Nuiqsut and Kuparuk pools will be developed separately, insufficient data are available to develop separate TUR forecasts. A single TUR forecast is estimated using an initial production of 2,000 BOPD in mid-2008 and a maximum rate of 16.2 MBOPD to be reached in 2016. The peak rate will be maintained for 1-yr period before declining to a final rate of about 0.68 MBOPD in 2050. A TUR of about 71,600 MBO is estimated using these parameters which results in a recovery of about 27% of 265 MMBO OOIP. The gas and water forecasts are made using the Alpine Unit. It is assumed all gas will be used for lease operation and in enhanced recovery processes.

Oooguruk Unit historical and future technically recoverable oil, gas, and water productions versus time are shown graphically in Figure 3-35. The individual oil production forecast is tabulated in Appendix A, Table A.1.

[59] ADNR 2008 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

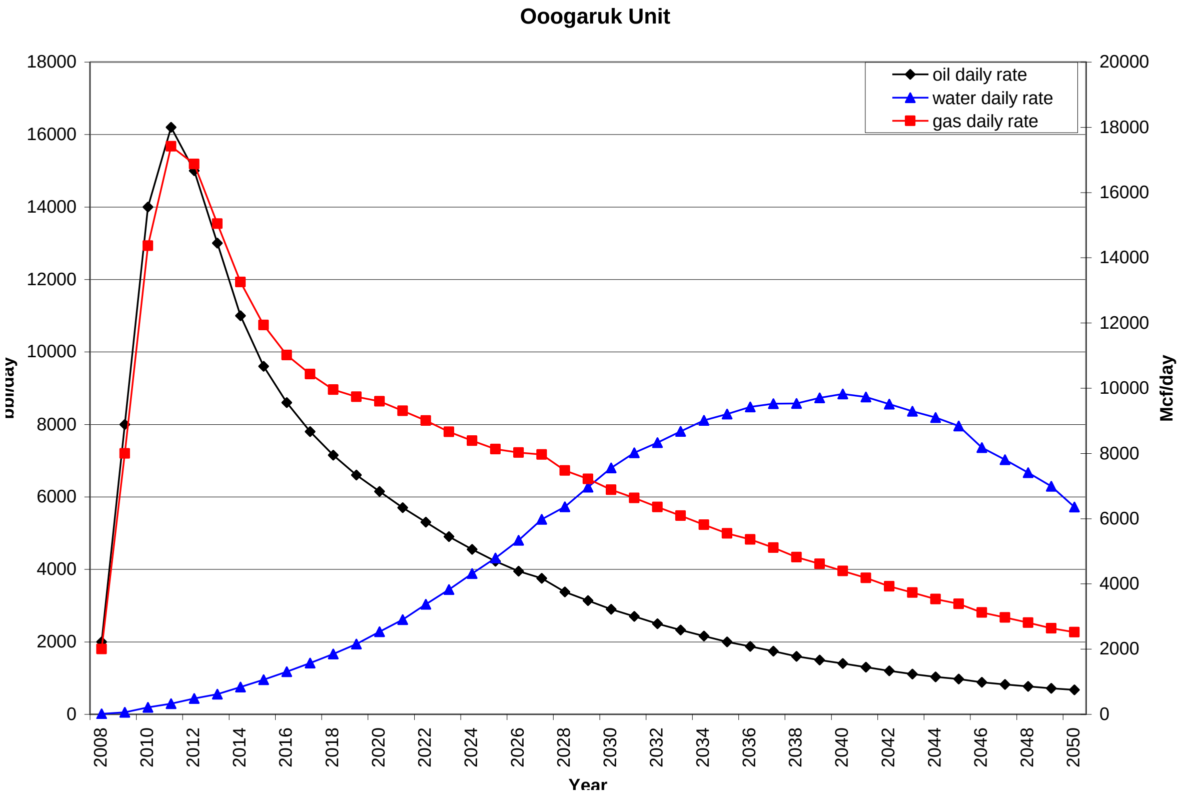

Figure 3-35. Oooguruk Unit production forecasts.

Oooguruk Unit forecasts of future and ultimate technical recoveries including the projects under development as of 1/1/2008 are presented in Table 3.32.

Table 3.32. Oooguruk Unit–Production statistics and forecasts as of 1/1/2008.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	71,600	71,600
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	71,600	71,600
Gas Production (MMCF)	0	116,153	116,153
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	78,465	78,465

3.2.32 Summary and Composite Curve of Producing Fields

A summary of the currently producing fields is shown in Table 3.33. **These volumes include any NGLs that have or will be recovered.** These fields had produced almost **15.7 BBO through 12/31/2007 and have an estimated TRR of about 6.2 BBO**.

Table 3.33. ANS Currently Producing Fields.

Pool/Field Name	OOIP (MBO)	TUR[a] (MBO)	Production 12/31/2007 (MBO)	TRR (MBO)	Recovery Factor
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	25,000,000	14,654,184	11,510,197	3,143,987	0.586
Aurora Participating Area (PA)	165,000	67,494	22,124	45,370	0.450
Borealis PA	350,000	144,420	48,307	96,113	0.413
Midnight Sun PA	60,000	22,351	16,612	5,739	0.373
Orion PA (Phase I & Phase II)	590,000	117,888	11,359	106,529	0.200
Polaris PA	303,700	78,251	6,543	71708	0.258
Lisburne PA	3,000,000	239,345	164,945	74,400	0.080
Niakuk PA	219,000	101,630	87,326	14,304	0.464
North Prudhoe PA	12,000	2,070	2,070	0	0.173
West Beach PA	15,000	3,582	3,582	0	0.239
Point McIntyre PA	1,120,000	571,052	413,934	157,118	0.510
Raven PA	14,000	4,553	1,641	2,912	0.325
Duck Island Unit (DIU)					
Endicott PA	1,059,000	591,593	466,240	125,353	0.539
Eider PA	13,000	2,754	2,754	0	0.212
Sag Delta North PA	18,000	8,178	8,178	0	0.454
Northstar Unit (NU)					
Northstar PA	375,000	204,585	122,390	82,195	0.546
Badami Unit (BU)	300,000	5,198	5,198	0	0.030
Kuparuk River Unit (KRU)					
Kuparuk River IPA	5,690,000	3,076,470	2,110,207	966,263	0.541
Meltwater PA	132,000	21,724	12,236	9,488	0.165
Tabasco PA	89,500	24,829	13,744	11,085	0.277
Tarn PA	525,000	161,720	86,019	75,701	0.308
West Sak PA	1,200,000[b]	263,018	32,283	230,735	0.219
Milne Point Unit (MPU)					
Kuparuk River IPA	850,000	385,986	206,386	179,600	0.454
Sag River PA	62,000	1849	1,849	0	0.030
Schrader Bluff PA	1,334,000[c]	295,404	53,304	242,100	0.221
Colville River Unit (CRU)					
Alpine Oil	875,000	519,359	260,116	259,243	0.594
Fiord PA – CD3	150,000	95,418	7,364	88,054	0.636
Nanuq-Kuparuk PA –CD4	120,000	43,049	6,753	36,296	0.303
Nanuq-Nanuq Sand PA – CD4	30,000	11,240	162	11,078	0.380
Qannik-Qannik PA – CD2	79,000	21,286	55	21,231	0.269
Ooogaruk Unit (OU)	265,000	71,600	0[d]	71,600	0.270
Total – currently producing fields	**44,015,200**	**21,812,080**	**15,683,878**	**6,128,202**	**0.496**

a. This volume includes any NGLs recovered.
b. Only 60% of the OOIP shown in Table 3.1 can be economically developed.
c. Only 66% of the OOIP shown in Table 3.1 can be economically developed.
d. Production began in 2008.

The historical production and forecasts of the technically recoverable **resources for the currently producing fields, including any active development projects for the currently producing fields, are shown in Figure 3-36. The individual field and pool forecasts for oil and NGLs are shown in Appendix A, Table A.1.** These production forecasts are without consideration of any economic constraints such as price or operating cost.

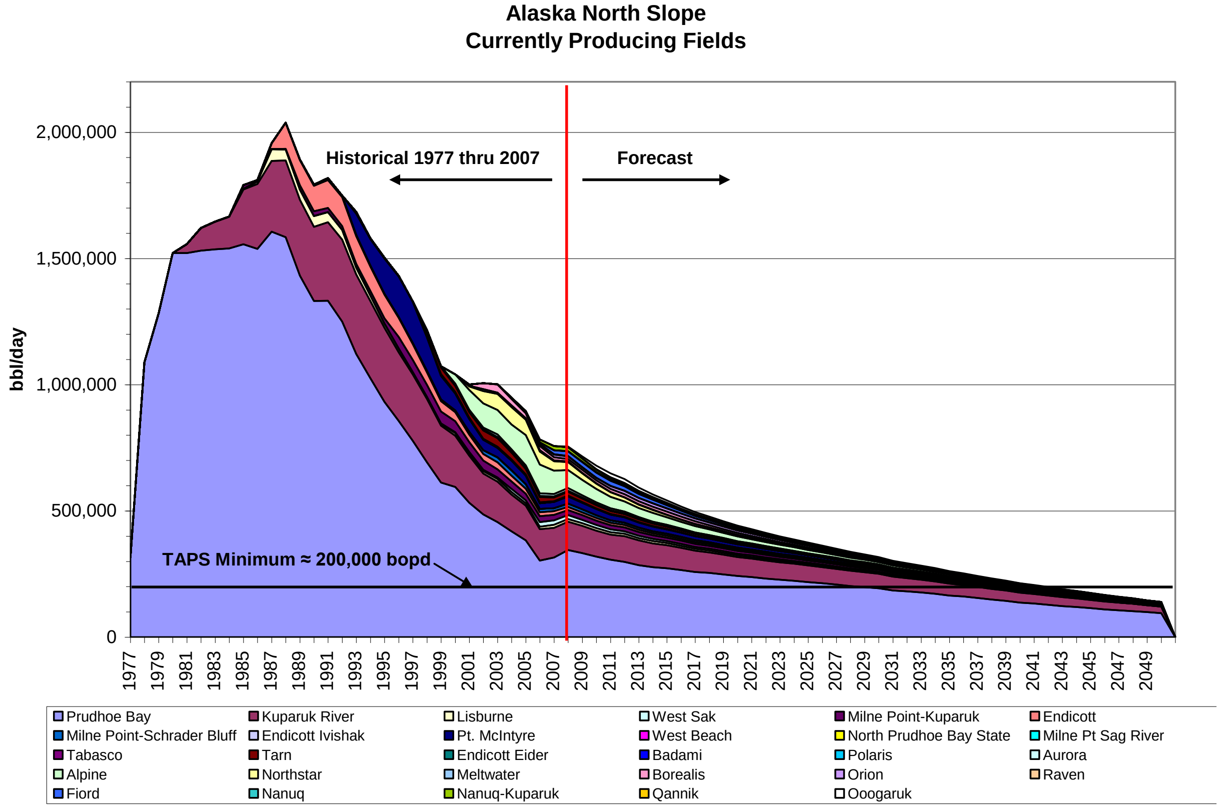

Figure 3-36. ANS currently producing fields – technically recoverable oil and NGL forecasts.

3.3 Known Pools with Announced or Pending Development Plans

This section will describe the engineering **evaluation** of fields and pools with announced or pending development plans. The information is taken from publicly available sources and includes **projects described in PODs available in May 2008**. The following pools: CRU Alpine West – CD5, CRU Lookout – CD6, CRU Spark – CD7, Gwydyr Bay Unit, Liberty Unit, and Nikaitchuq Unit **are evaluated**. See Figure 1-2 for field locations. **The forecasts for these fields are tabulated in Appendix A, Table A.2.**

3.3.1 Colville River Unit Satellite – Alpine West Pool – CD5

The Alpine West pool was discovered in 2001 and is an assumed accumulation of about 150 MMBO OOIP in the Alpine sandstone. The pool is a satellite to the CRU Alpine PA and is located about **4 miles from the Alpine CD2 Drillsite.**[60] **Engineering analysis to determine the technically recoverable resources is described in this section.**

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[60] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Development is expected to begin in **2008 and continue through 2010**. **Development will include two road bridges.** Drilling is planned to begin in mid-2008 and be completed in 2010 and will include **16 horizontal wells**. **There will be eight producers and eight injectors in the expected case.** Produced fluids will be processed by the Alpine PA facilities. **A horizontal pattern MWAG flood** will be employed.

Pending permit approval, production is **expected** to begin in **2010 and reach a peak of about 13 MBOPD in 2011**. Production **is assumed to** be level for **two years** before beginning a **decline** to an abandonment rate of about **0.43 MBOPD in 2045**. This results in a TUR of **55,706 MBO. The reservoir is considered to be more of a typical quality as compared to Alpine PA reservoir, with a recovery of about 37%.**

Gas and water production volumes **are** estimated using the **GOR** and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process.

Alpine West pool future technically recoverable oil, gas, and water **productions versus time are shown graphically in Figure 3-37. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

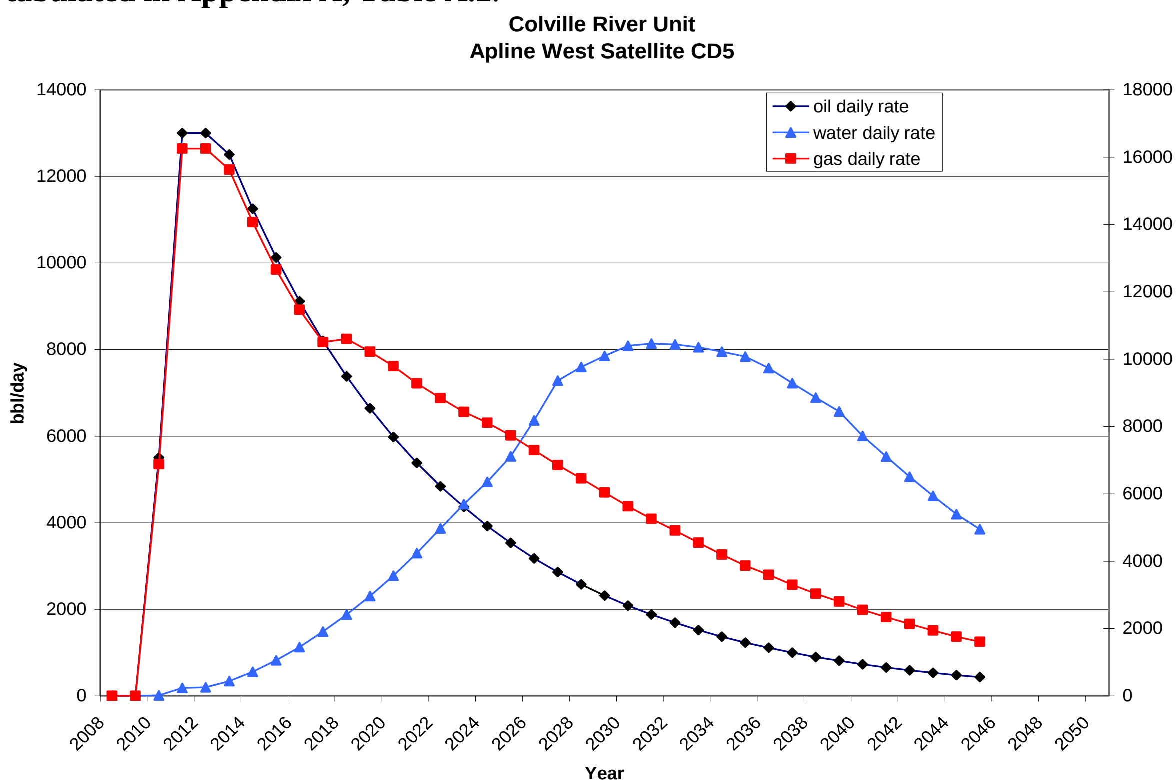

Figure 3-37. Colville River Unit – Alpine West production forecasts.

Forecasts of the Alpine West pool future and ultimate **technical recoveries** are presented in Table 3.34.

Table 3.34. Colville River Unit–Alpine West pool production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	55,706	55,706
NGL Production (MB)	0	0	0
Oil and NGLs (MB)	0	55,706	55,706
Gas Production (MMCF)	0	93,727	93,727
Gas Injection (est.) (MMCF)	0	70,000	70,000
Water Production (MB)	0	61,342	61,342

3.3.2 Colville River Unit Satellite – Lookout Pool – CD6

The Lookout pool was discovered in 2002 and is an assumed accumulation of 150 MMBO OOIP, in the Alpine sandstone. The pool is a satellite to the CRU Alpine PA and is located about 15 miles southwest of the Alpine oil field (PN, 2005). **Engineering analysis to determine the technically recoverable resource is described in this section.**

The Lookout pool satellite was believed to contain as much as 67.5 MMBO of TUR (Table 2.5). However, based on recent comments by the operator (PN, 2005e), a conservative volume of about 50 MMBO is **assumed** in this analysis. Production will be processed by the Alpine PA facilities. It will be transported through a three-phase pipeline to connect to the three-phase pipeline at the Alpine West production pad. The initial development work on this satellite is delayed until development of the Spark pool satellite is **commenced (Section 3.3.3)**. This will allow for the three-phase pipeline cost to be shared. It is assumed development work will commence in **2011** with initial wells being drilled in **2012**. **It is assumed that** 20 wells including producers and injectors will be required.

Production is assumed to begin in **2013** and reach a peak rate of about **19.3 MBOPD** in late **2015**. That peak rate will be maintained for a year before starting a 15% per year decline rate to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about **53,910 MBO**.

Gas and water production volumes **are** estimated using the **GOR** and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for **lease operations**.

Lookout pool future technically recoverable oil, gas, and water **productions versus time are shown graphically in Figure 3-38. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

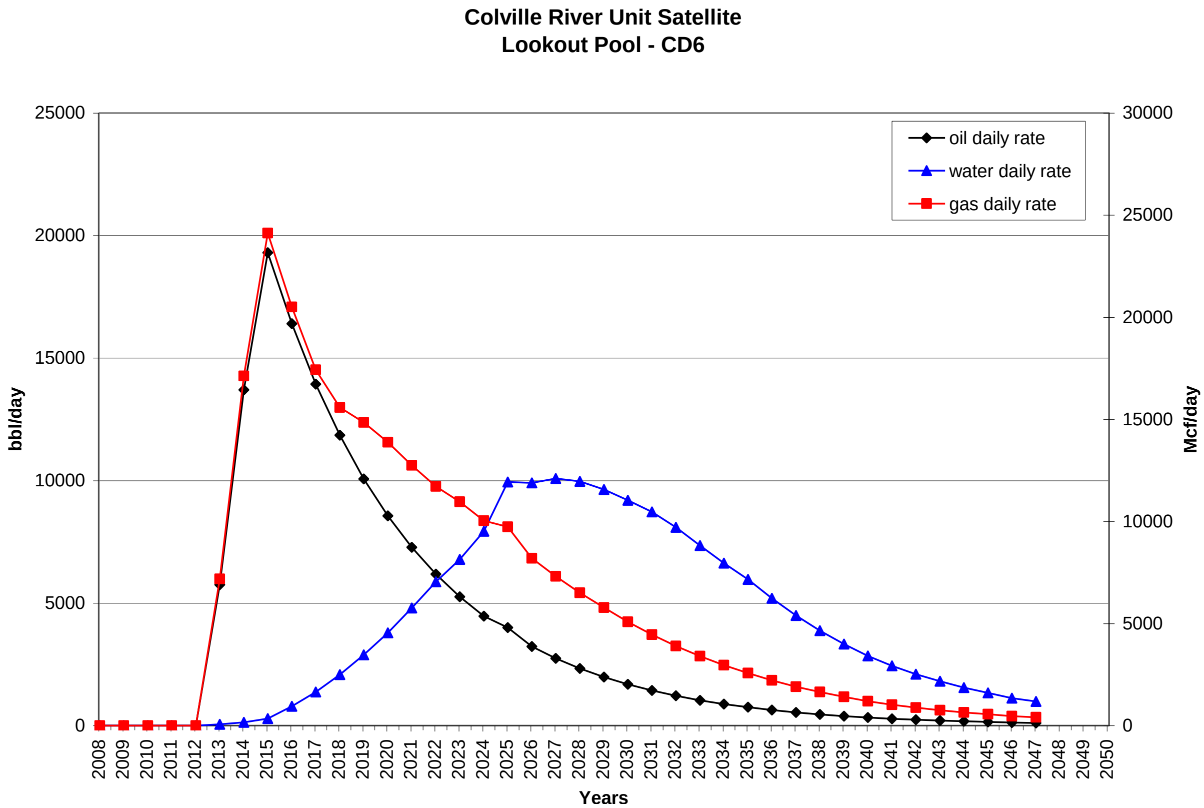

Figure 3-38. Lookout pool production forecasts.

Forecasts of Lookout pool future and ultimate **technical recoveries** are presented in Table 3.35.

Table 3.35. Lookout pool production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	53,910	53,910
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	53,910	53,910
Gas Production (MMCF)	0	90,951	90,951
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	59,639	59,639

3.3.3 Colville River Unit Satellite – Spark Pool – CD7

The Spark pool was discovered in 2000 and is an assumed accumulation of 150 MMBO OOIP, in the Alpine sandstone. The Spark pool is a satellite to the CRU Alpine PA and is located about 20 miles southwest of the Alpine oil field development (PN, 2005). **Engineering analysis to determine the technically recoverable resources is described in this section.**

The Spark pool satellite was believed to contain as much as 67.5 MMBO of TUR (Table 2.5). However, a conservative estimate of about 50 MMBO is used **for this analysis**. Indications are that all produced fluids would be transported to the Alpine IPA facilities for processing. This may be the maximum distance three-phase fluids can be transported on the North Slope (**Department of Interior** (DOI) (2004b). A joint three-phase line will be constructed to the Lookout pool (see Section 3.3.2). It is assumed development work will commence in 2008 with initial wells being drilled in 2009. A total of 20 wells including producers and injectors will be required.

Production is assumed to begin in **2013** and reach a peak rate of about **19.3 MBOPD** in late **2015**. That peak rate will be maintained for a year before starting a 15% per year decline rate to an abandonment rate of about 0.1 MBOPD, resulting in a TUR of about **53,910 MBO**.

Gas and water production volumes will be estimated using the **GOR** and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for **lease operations**.

Spark pool future technically recoverable oil, gas, and water **productions versus time are shown graphically in Figure 3-39. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

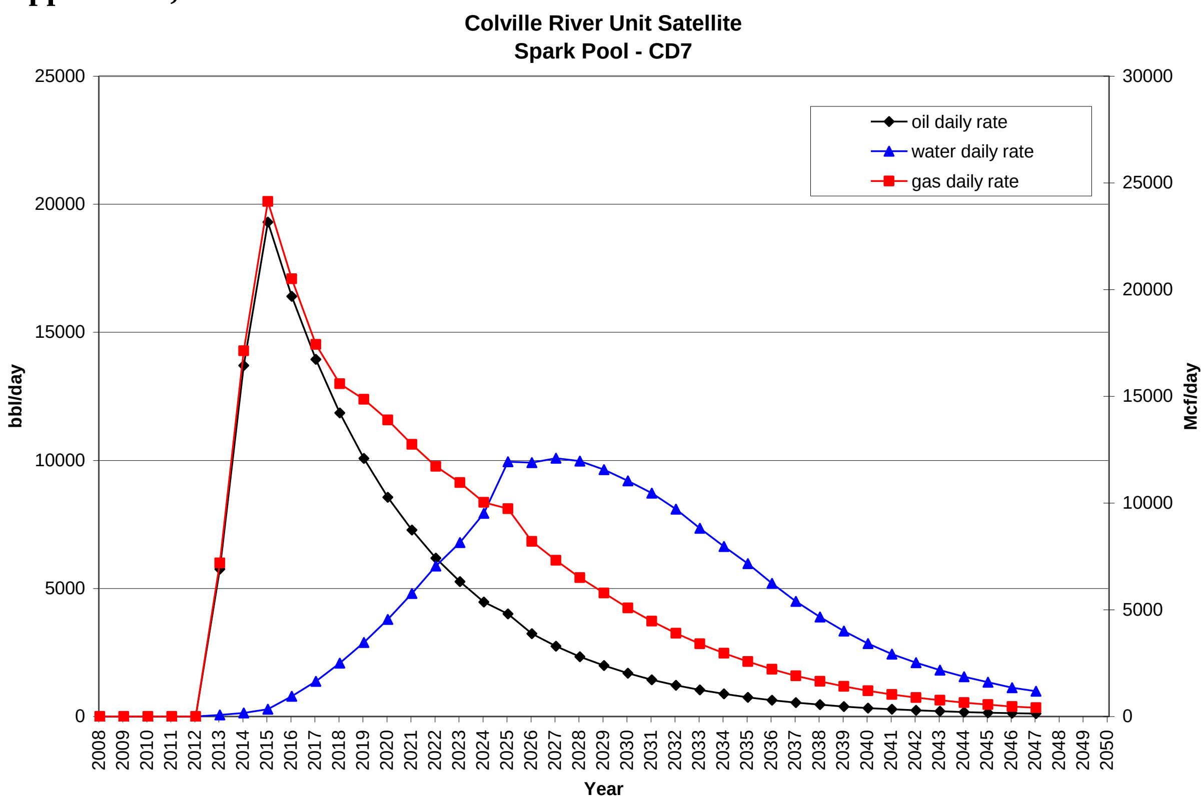

Figure 3-39. Spark pool production forecasts.

Forecasts of Spark pool future and ultimate **technical recoveries** are presented in Table 3.36.

Table 3.36. Spark pool production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	53,910	53,910
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	53,910	53,910
Gas Production (MMCF)	0	90,951	90,951
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	59,639	59,639

3.3.4 Gwydyr Bay Unit

The Gwydyr Bay Unit (GBU) is an assumed accumulation of about **150 MMBO OOIP** in the Ivishak Formation and was discovered in 1969 (Table 2.6). It is north of PBU and is located on both onshore tracts and offshore Beaufort Sea tracts. The unit is estimated to contain between 30,000 and 60,000 MBO of recoverable resources (Table 2.6).

A published report indicated initial development could begin as early as **2008** with first production beginning in **2010** (PN, 2004i). It is assumed production will be processed by the PBU Lisburne PA facility.

The annual production rates and the TUR for the GBU are estimated using the following parameters. Initial development will commence in **2009** and will include pad and facility construction and well drilling. Production is assumed to begin in mid-**2011**. **A previous source indicated** development **would** require from 5 to 12 wells (PN, 2004i). A peak rate of 15 MBOPD is assumed with a 2-yr peak production period. Rates are determined using a 15% per year decline rate to an abandonment rate of about **0.29 MBOPD in 2040**. This results in a TUR of about **53,436 MBO. Development of the offshore and onshore reservoir contains a degree of uncertainty, therefore the more conservative recovery of about 36% is used.**

It is assumed both water and gas will be used for enhancing recovery, similar to the Northstar Ivishak project. Future gas and water recovery forecasts are **estimated using NU gas and water performance history**. All gas is assumed to be used on lease.

Gwydyr Bay Unit future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-40. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

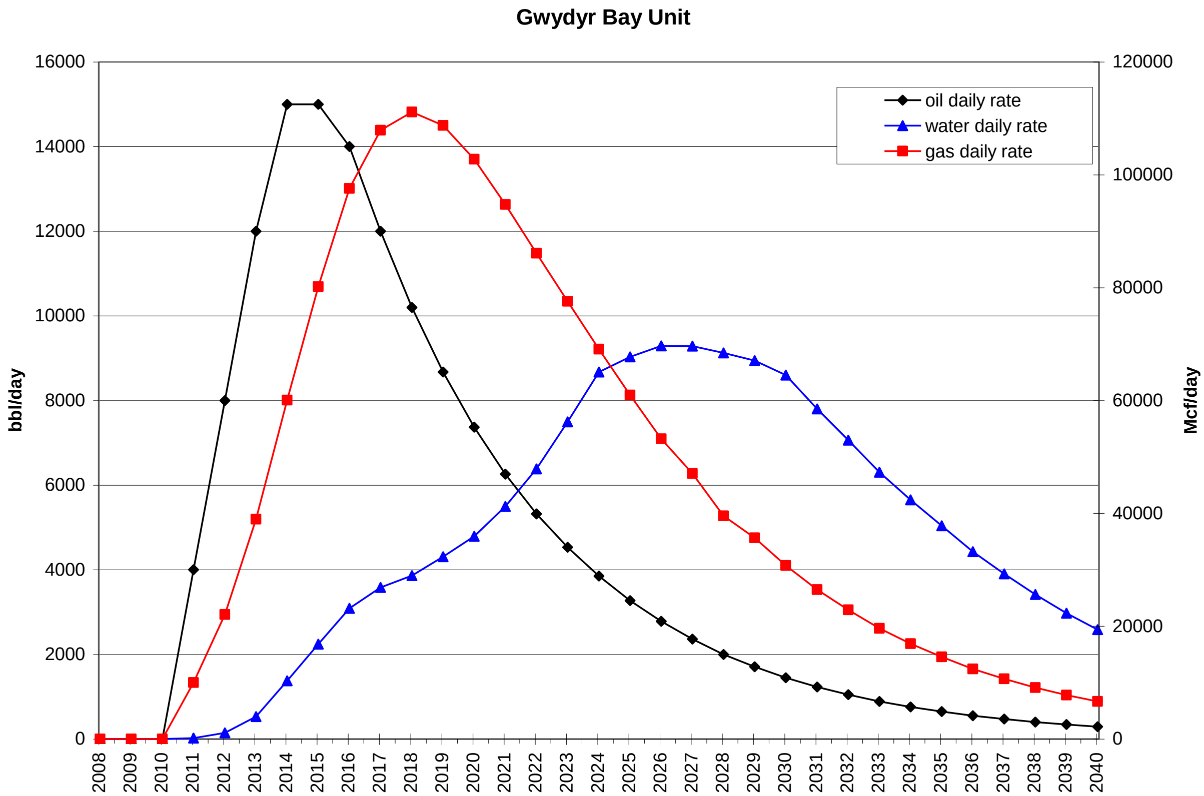

Figure 3-40. Gwydyr Bay Unit production forecasts.

Forecasts of GBU future and ultimate **technical** recoveries are presented in Table 3.37.

Table 3.37. Gwydyr Bay Unit production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	53,436	53,436
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	53,436	53,436
Gas Production (MMCF)	0	540,633	540,633
Gas Injection (Est.) (MMCF)	0	435,000	435,000
Water Production (MB)	0	56,727	56,727

3.3.5 Liberty Unit

The Liberty Unit (LU) is an assumed accumulation **of about 300 MMBO OOIP** in the Kekiktuk Conglomerate Formation discovered in 1982 (Table 2.5). It is located off-shore between the Duck Island and Badami Units. Recoverable resources are estimated at about **100 MMBO (PN, 2008i)**.

Project approval **was announced by the operator in July 2008 (PN, 2008c)**. Plans are to **enlarge the Endicott Island to accommodate the facilities for drilling six extended reach**

wells (34,000 to 44,000 feet) to develop the pool. **It will require a total of six producers and injectors to be drilled. It is assumed these will be drilled over a 3-year** period beginning in 2010 and that production will begin in **2011**. **It is assumed** the reservoir will be operated under a waterflood/pressure maintenance program initiated in **2011, with an EOR project applied shortly after production is initiated**.

Technically recoverable oil and gas is estimated using a peak production rate of 35 MBOPD **in 2013**. **Production is assumed to decline to an** abandonment rate of about **1.0 MBOPD in 2035**. This results in a TUR volume of about **107,000 MBO**.

Gas and water forecasts are estimated using **Northstar** historical data.

Liberty Unit future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-41. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

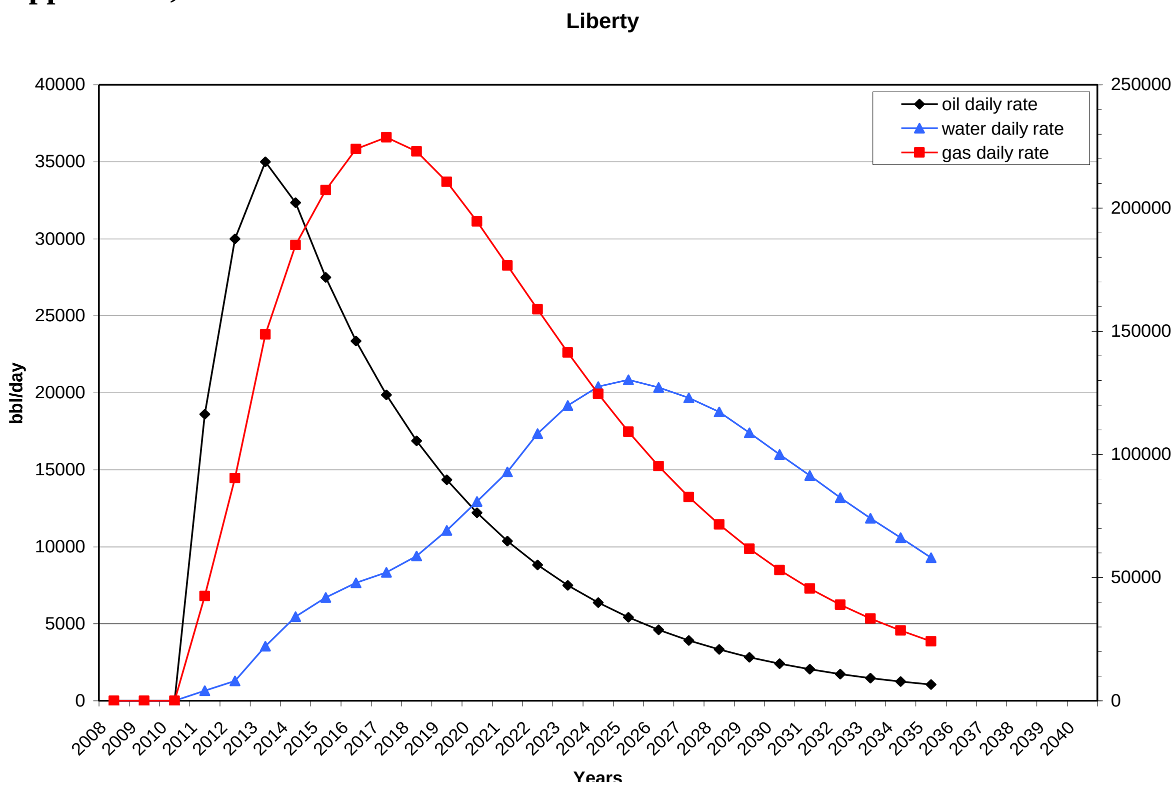

Figure 3-41. Liberty Unit production forecasts.

Forecasts of Liberty Unit future and ultimate technical recoveries are presented in Table 3.38.

Table 3.38. Liberty Unit production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	107,000	107,000
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	107,000	107,000
Gas Production (MMCF)	0	1,094,864	1,094,864
Gas Injection (Est.) (MMCF)	0	875,000	875,000
Water Production (MB)	0	113,646	113,646

3.3.6 Nikaitchuq Unit

The Nikaitchuq Unit and is an assumed accumulation **of 486 MMBO OOIP** in the Nuiqsut and Sag River sandstones and the Schrader Bluff Formation. **The Unit was recently expanded to include the Tavaaq Unit. The Unit pools were** discovered in 2004 (Table 2.5**)**, **and are** located offshore and north of the Kuparuk River and Milne Point Units. **Technically recoverable resources for the Nikaitchuq Unit** were **previously estimated** to be about **175 MMBO and the TUR for the Tauvaaq Unit was estimated to be about 75 MMBO**. **Based on drilling results to date, the estimates are believed to be high.** Recoverable resources and production rates are estimate using the following information.

Eight delineation wells have been drilled to evaluate the three pools; however, no production tests have been released. Seismic data are being obtained to assist in the evaluation. Based on favorable evaluation, it is assumed development will occur. Until other information is available, the operator's news release (PN, 2005g; PN, 2005h) **will be used in this recoverable resource estimate**. **That plan indicates the accumulation will be developed using two on-shore and three off-shore pads. The plan also indicates that 20 wells will be drilled at the onshore drilling pads and 50 wells in each of the three off-shore pads. However, with the new drilling technology and extended reach capability, that plan could be revised. Drilling is assumed to begin in 2012 at the on-shore pads and require two to three years to complete.** Drilling at the three off-shore pads is assumed to begin in **2013** and will also require two to three years to complete. **It is assumed all development drilling will be completed in 2016.** Initial production **is assumed** to commence in late **2012 and increase gradually under an assumed staged development**. Total production from the project is **assumed to be about 25 MBOPD in 2016 and remain at that level through 2018 (PN, 2005g). Development of the reservoir as a combination of onshore and offshore development results in the assumption of a more conservative production decline rate. Until production performance is available it is assumed production will decline at an average of 10% per year. Using a final rate of 0.85 MBOPD in 2050 results** in an estimated TUR of about **129.7 MMBO.**

The gas and water forecasts are made using the Milne Point Schrader Bluff historical data.

Nikaitchuq Unit future **technically recoverable** oil, gas, and water **productions versus time are shown graphically in Figure 3-42. The individual oil production forecast is tabulated in Appendix A, Table A.2**.

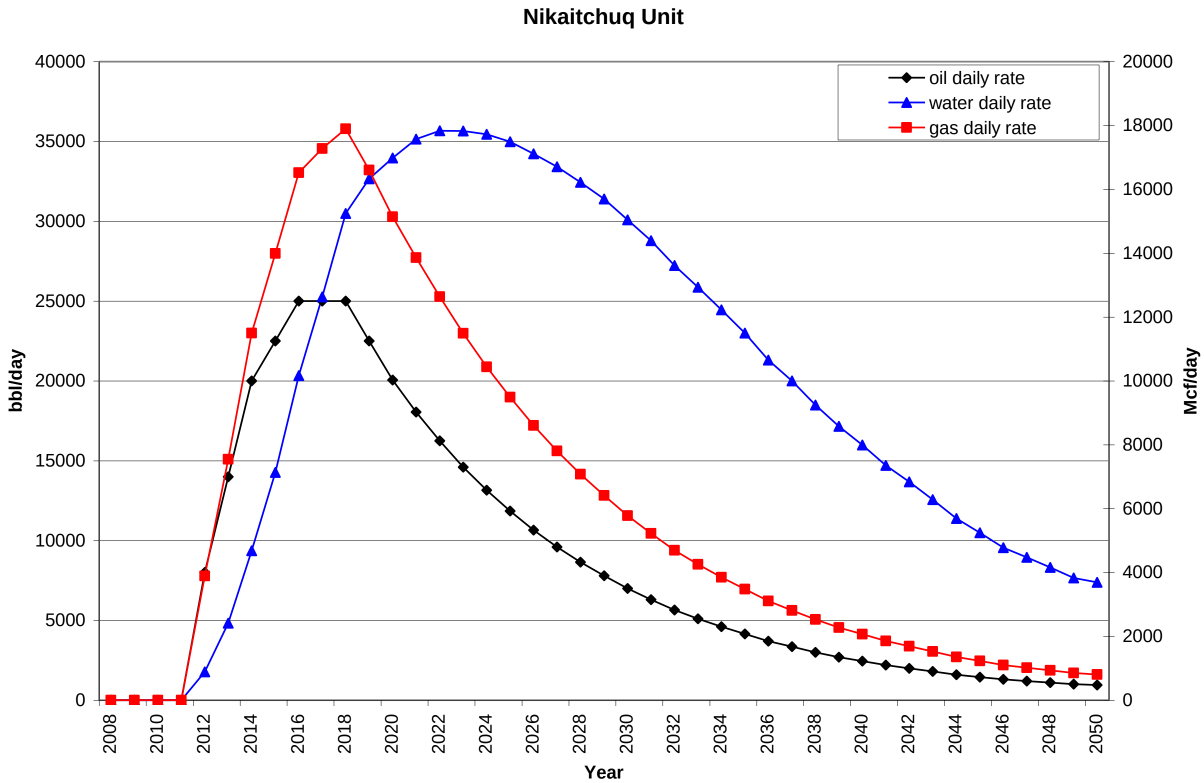

Figure 3-42. Nikaitchug Unit production forecasts.

Forecasts of Nikaitchug Unit future and ultimate technical recoveries are presented in Table 3.39.

Table 3.39. Nikaitchug Unit production statistics and forecasts.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	129,666	129,666
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	129,666	129,666
Gas Production (MMCF)	0	95,131	95,131
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	305,979	305,979

3.3.7 Summary for Known Fields with Pending or Announced Development Plans

A summary of the known fields with pending or announced development plans are shown in Table 3.40. These fields will add an additional TRR of almost **0.5 BBO** to the TRR for the currently producing fields for a total of **6.7 BBO**.

Table 3.40. ANS known fields with pending or announced development plans.

Pool/Field Name	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
KNOWN FIELDS WITH PENDING OR ANNOUNCED DEVELOPMENT PLANS					
Colville River Unit (CRU)					
Alpine West Pool – CD5	150,000	55,706	0	55,706	0.371
Lookout Satellite – CD6	150,000	53,910	0	53,910	**0.359**
Spark Satellite – CD7	150,000	53,910	0	53,910	**0.359**
Liberty Unit (LU)	300,000	107,000	0	107,000	**0.357**
Gwydyr Bay Unit (GBU)	150,000	53,436	0	53,436	**0.356**
Nikiatchuq Unit (NU)	486,000	129,666	0	129,666	**0.267**
Total–Fields with announced or pending development plans	**1,386,000**	**453,628**	**0**	**453,628**	**0.327**

The composited forecast for the known fields with pending or announced development plans is shown on Figure 3-43. **This is the same as Figure 3-36 with the additional forecasts added. These production forecasts are without consideration of any economic constraints such as price or operating cost.**

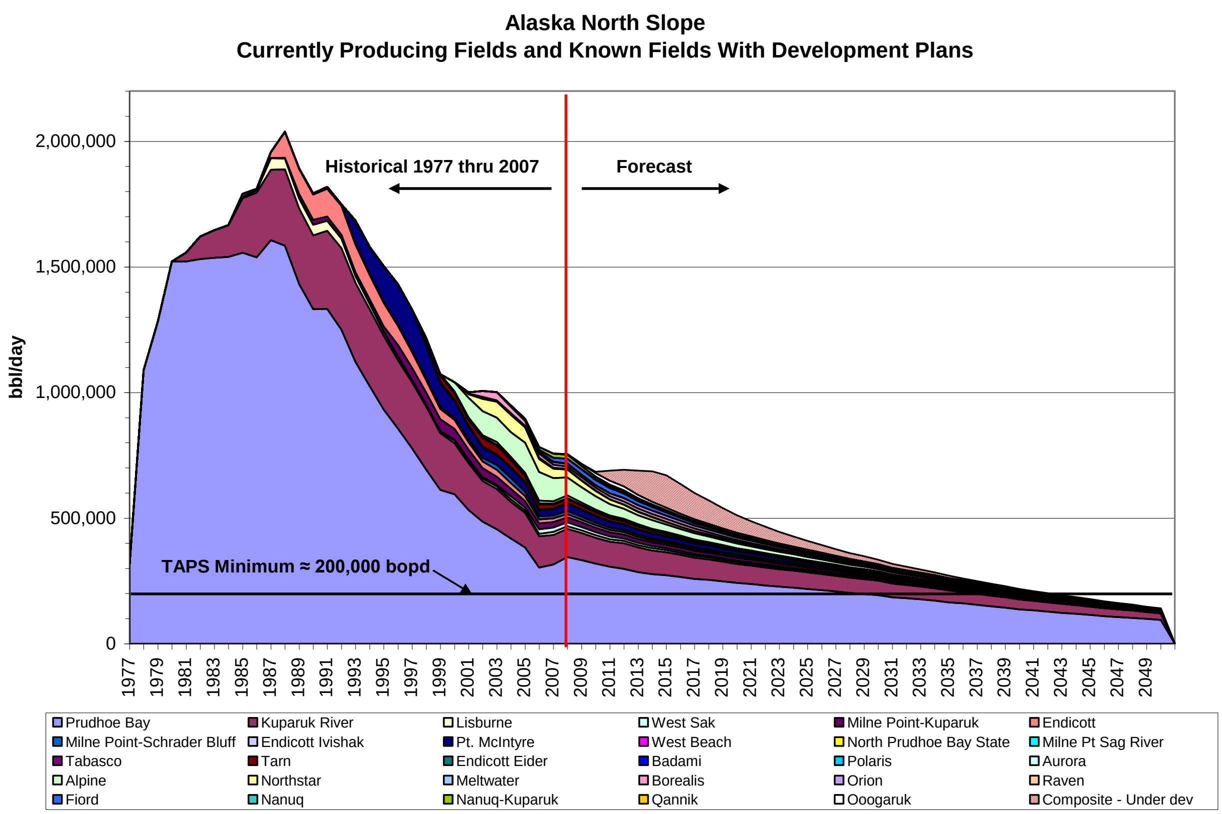

Figure 3-43. Technical production forecasts for ANS known producing fields and fields with announced or pending development plans.

3.4 Known Pools and Projects under Evaluation

Evaluations of two types of potential resource accumulations are discussed in this section: (1) active producing pools that have development expansions under evaluation but not fully justified at this time; (2) known resource accumulations being considered for development and in varying levels of evaluation. The first group includes PBU Borealis, PBU Orion, PBU Polaris, Kuparuk West Sak, and CRU Nanuq. The second group includes Sandpiper, Sourdough, and Sambuca prospects. The Point Thomson field is under evaluation but it is unlikely that it will be developed until a gas pipeline is built. Currently the State of Alaska has revoked the leases (see Section 2.3.3.1.4).

3.4.1 Producing Pool with Projects under Evaluation

The following producing pools are assumed to have potential resource additions as a result of enlarging the developed area by drilling additional wells or by installing or expanding an EOR project. Because the location and timing of these projects is not defined, estimates of future gas and produced water volumes is difficult. Therefore, only a forecast of the technically recoverable resources is given.

3.4.1.1 Prudhoe Bay Unit – Borealis PA – Under Evaluation

Currently about 20% of the reservoir is receiving miscible injectant. It is too soon for results to be detected. Positive results would lead to an expansion to at least 40% of the reservoir volume. Based on an OOIP of 350 MMBO, an expansion to about 40% of the reservoir, and a 5% increased recovery, technically recoverable resources would be increased by about 7,000 MBO.

Additonal undeveloped areas around the I Pad and an east expansion of the Borealis PA are under evaluation. If evaluation of data shows these areas could be developed, at least five wells are assumed to be required to complete the development. The potential recovery of these wells is based on the forecast of the current developed area, which indicates that the average per well recovery is about 4,300 MBO. The per-well recovery used for the areas under evaluation is reduced by 40% because the two areas may be in lower quality reservoir. It is assumed that five additional wells are required to recover a TUR of about 13,000 MBO.

If successful, the projects under evaluation could result in TRR of about 20,000 MBO for EOR and new wells.

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts.

3.4.1.2 Prudhoe Bay Unit – Orion PA – Under Evaluation

Phase I and Phase II have been or under development. Phase III is assumed to be under evaluation and expansion of the recovery process to this area is expected and will be based on the results from the first two stages. Results to date appear to support continued expansion of the project into the Phase III area. Therefore, it is assumed development will commence in 2011 with initial production occurring in 2012. The Phase III wells are assumed to recover the same volume of oil as estimated for the Phase II wells or 5,125

MBO per well for 19 producers. This results in a TUR of 97,375 MBO for the Phase III area based on.

Currently MI is being injected into five wells, with initial injection occurring in October 2006. These wells will be used to evaluate the EOR process. It is too soon for results to be evident. It is assumed the EOR process will be successful and the MI process will be used over the entire reservoir. Recovery is estimated using a 5% recovery factor of an assumed OOIP volume of 1.07 BBO for a TUR of 53,500 MBO.

A combined recovery forecast is made for these two estimates. An initial production rate of 3.550 MBOPD for 2012 with production gradually increasing to a peak of 25 MBOPD for 2018. Production is then declined at 7% per year to a final rate of 2.550 MBOPD in 2050. This results in a total TRR of 150,875 MBO (53,500 MBO from EOR plus 97,375 MBO from development drilling).

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts. The individual oil production forecast is tabulated in Appendix A, Table A.3.

3.4.1.3 Prudhoe Bay Unit – Polaris PA – Under Evaluation

The Polaris pool OOIP is assumed to be about 70% developed and currently being developed. The remaining 30% OOIP (126,300 MBO) consists of an area under evaluation. The results from the producing area and the area currently being developed will be used to justify the expanding development to the remaining 30% OOIP reservoir volume. If expansion is made, it is assumed a total of four horizontal wells will be required. It is assumed that the recovery from this area will be less than for the producing area. The average per-well recovery for wells in the producing area is used to estimate the recovery. Average per-well recovery is about 3,925 MBO. Using the assumed four producing wells per development results in a TUR of about 15,700 MBO and a recovery of about 12.4%.

The forecast of this potential technically recoverable resource was made using an initial rate of 0.500 MBOPD in 2011 with production increasing to a peak of 3.05 MBOPD in 2014. Production is then declined at about 7.5% per year to a final rate of 0.2 MBOPD in 2048. This gives a recovery of 15,700 MBO.

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts. The individual oil production forecast is tabulated in Appendix A, Table A.3.

3.4.1.4 Kuparuk River Unit – West Sak – Under Evaluation

The western KRU West Sak area under evaluation contains an estimated 800 MMBO OOIP and would be developed if proven technically and economically viable.

The net pay in this area is thinner than in the developed and under development areas.[61] If developed, this recovery is assumed to be about 21% of the OOIP or about 167,776 MBO. Development will use multilateral long-reach completions. The recovery process is assumed to be waterflood to maintain reservoir pressure and increase sweep efficiency. If an EOR process is proven successful in the developed area, it is assumed it would be applied to the Western West Sak area.

The development of this area of West Sak could be in conjunction with development of the Ugnu reservoir, if proven technically and economically feasible. No forecast of recovery for the Ugnu reservoir is included.

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts. The individual oil production forecast is tabulated in Appendix A, Table A.3.

3.4.1.5 Colville River Unit, Alpine PA

Plans are being made to test part of the undeveloped Alpine reservoir to determine the economics of further development of an area assumed to be of lower quality. It is assumed a well will be completed in 2009, and will recover 75% of the average ultimate recovery of the existing producers. The TRR estimate for this well is about 7,950 MBO. If this well is successful as assumed, then additional drilling prospects are possible. An assumption of five additional wells is reasonable. If successful, a TRR of about 40,000 MBO is possible.

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts. The individual oil production forecast is tabulated in Appendix A, Table A.3.

3.4.1.6 Colville River Unit, Alpine Field – Nanuq – CD4

Implementation of EOR technology is necessary in the Nanuq CD4 project. The recovery process at CD4 is a horizontal pattern MWAG flood in both the Nanuq and Kuparuk Reservoirs. The first miscible injectant is assumed to have begun in June 2007.[62] It is too soon for the results to be detected; however, modeling and laboratory evaluation have indicated the MWAG process will increase recovery in both reservoirs. This process could increase recovery by about 10% of estimated future recovery from both formations. The forecast totals about 4,850 MBO.

The production forecast for this estimated technically recoverable resource is shown in Figure 3-47 as part of the composite Under Evaluation forecasts. The individual oil production forecast is tabulated in Appendix A, Table A.3.

3.4.1.7 Summary of Under Evaluation Pools and Projects

A summary of the estimated technically recoverable oil is presented in Table 3.41.

[61] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.
[62] ADNR 2007 POD. The Plans of Development are available at the Alaska Department of Natural Resources.

Table 3.41. Known pools with projects under evaluation–Forecasts of ultimate technically recoverable resources.

Variable	Technically Recoverable Oil (MBO)
Prudhoe Bay Unit.- Borealis PA	20,000
Prudhoe Bay Unit.- Orion PA	150,875
Prudhoe Bay Unit.- Polaris PA	15,700
Kuparuk River Unit – West Sak	167,775
Colville River Unit Alpine PA	40,000
Colville River Unit Alpine-Nanuq—CD4	4,850
Total for Pools and Projects Under Development	**399,200**

3.4.2 Discovered Fields with Development Potential

The following discovered but undeveloped pools are under evaluation to varying degrees. The evaluations have not progressed to justify announcing plans for development. The forecasts of these potential accumulations are made by comparison to an existing producing pool and based on published data. Forecasts of oil, gas, and water produced volumes are made for each potential accumulation.

3.4.2.1 Sandpiper Prospect

The Sandpiper prospect is an assumed accumulation **of about 450 MMBO OOIP** in the Ivishak Formation. The field was discovered in 1986 by Shell (Table 2.6) using a man-made gravel island. A unit was formed in 1992. It is located northwest of the NU in federal waters (Thomas et al., 1993). **Technically recoverable resources is assumed to be** about **150,088 MBO.**

Several leases in the Sandpiper area were acquired in a 2003 MMS lease sale (OGJ, 2003). No published information has been found regarding exploration and development activity in the former Sandpiper Unit area. It is assumed that potential development cannot occur before 2013. Development will include constructing a production and drilling pad north of a barrier island. It is assumed the pad will be positioned to allow long reach/horizontal wells to develop the accumulation and that produced fluids will be processed through an existing on-shore facility.

It is assumed both water and gas will be used for pressure maintenance and enhanced recovery. Future gas and water recovery forecasts are determined using the NU oil and water historical data. It is assumed gas not used in lease operations will be disposed of on-shore.

Sandpiper future technically recoverable oil, gas, and water **productions versus time forecasts are presented graphically in Figure 3-44. The individual oil production forecast is tabulated in Appendix A, Table A.4.**

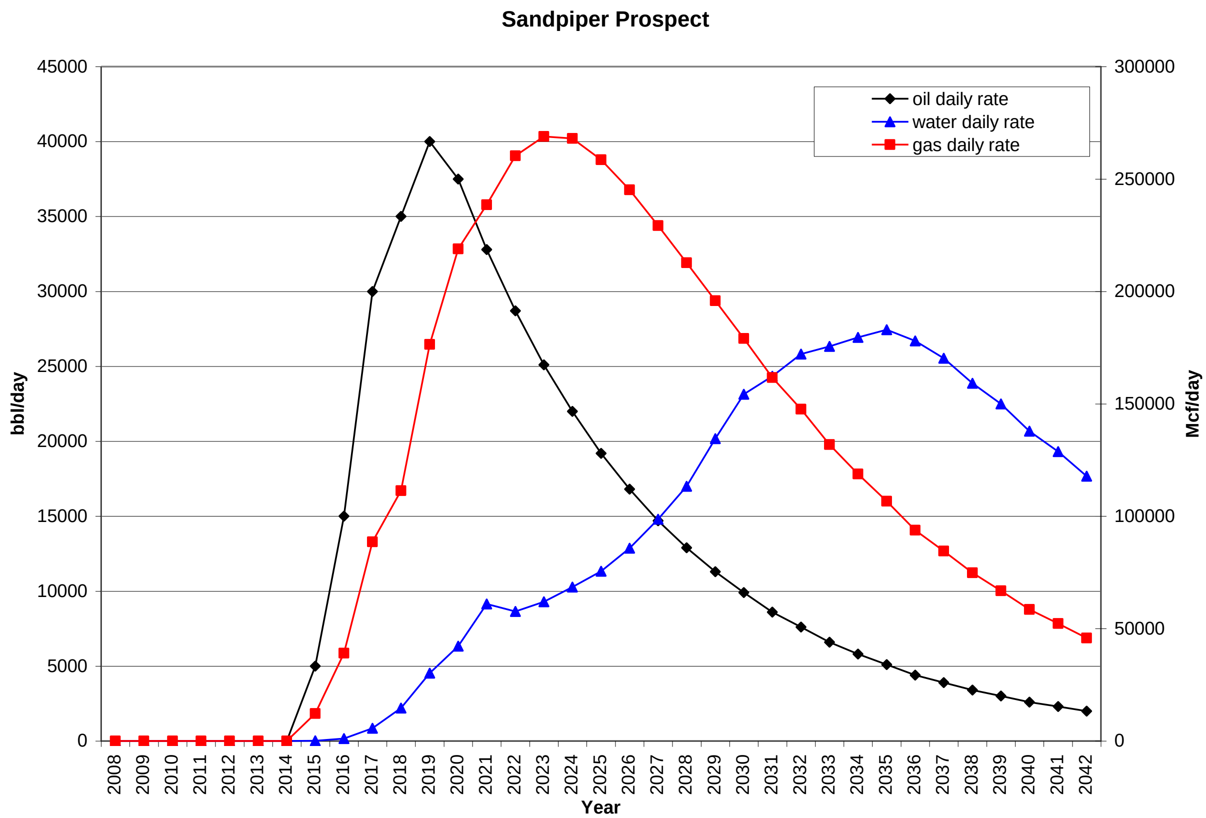

Figure 3-44. Sandpiper production forecasts.

Forecasts of Sandpiper future and **ultimate technically recoverable** oil, gas, and water are presented in Table 3.42.

Table 3.42. Sandpiper–Forecasts of ultimate technically recoverable resources.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	150,088	150,088
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	150,088	150,088
Gas Production (MMCF)	0	1,513,491	1,513,491
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	159,811	159,811

3.4.2.2 Sambuca Satellite

The Sambuca satellite is an **assumed** accumulation **of about 60 MMBO OOIP** in the Ivishak Formation. **The field** was discovered in 1997 (Table 2.6). It is located within PBU and is adjacent to the Midnight Sun satellite. **Technically recoverable resources** are thought to be about 19,000 MBO (Table 2.6).

It is assumed the wells for this accumulation will be drilled from the existing well pad used by the Midnight Sun satellite and that development will begin in 2008 and will require six total wells drilled over three years. Development will include the associated surface equipment. Production will be transported to the nearest PBU processing facility. Water injection will be used for pressure maintenance and secondary recovery.

The production forecast to recover the indicated ultimate resources is made using mid-2008 as production start-up; a 2-yr period to reach a peak rate of 7.0 MBOPD, held for one year; and then declined at 15% per year to an assumed abandonment rate of about 0.03 MBOPD. This results in an estimated TUR of **20,601 MBO**.

Until data become available for this satellite, gas and water production forecasts are determined using the historical production data from the Midnight Sun accumulation.

Sambuca future **technically recoverable oil, gas, and water production versus time forecasts are presented graphically Figure 3-45. The individual oil production forecast is tabulated in Appendix A, Table A.4.**

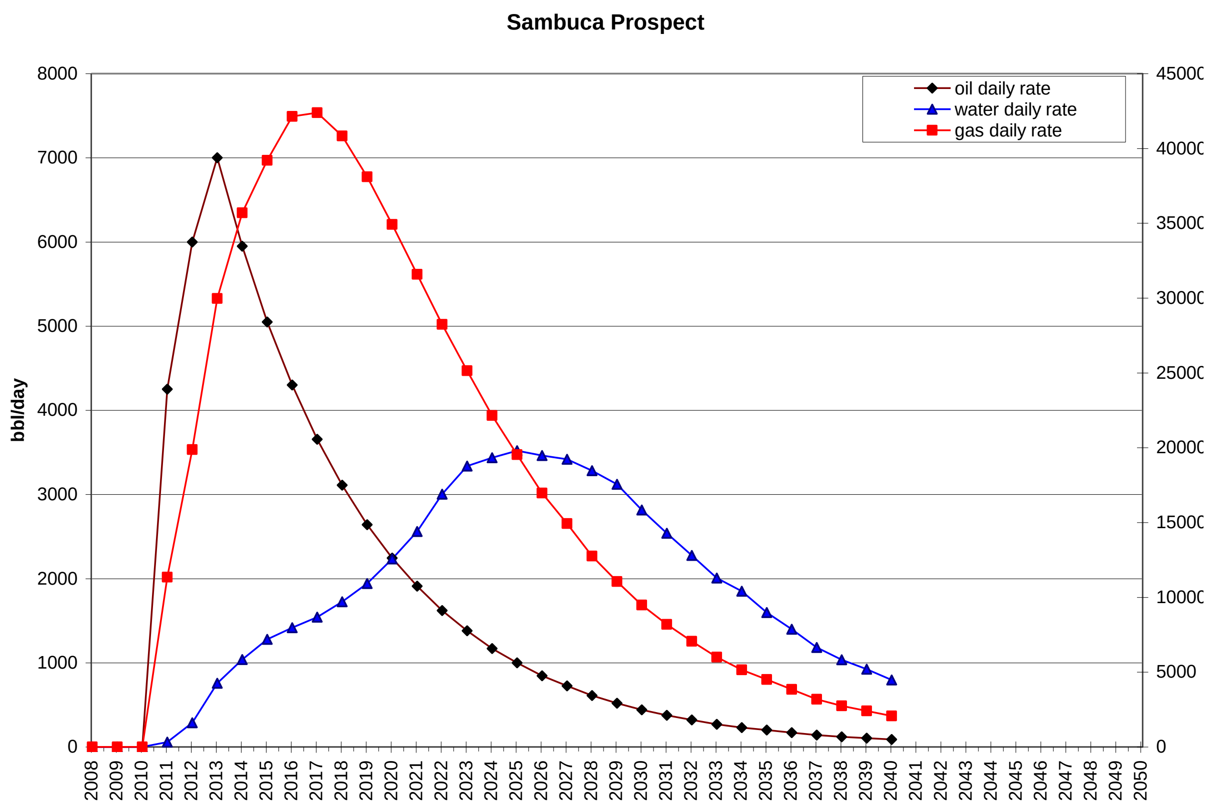

Figure 3-45. Sambuca production forecasts.

Forecasts of Sambuca future and ultimate technically recoverable oil, gas, and water are presented in Table 3.43.

Table 3.43. Sambuca–Forecasts of ultimate technically recoverable resources.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	20,600	20,600
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	20,600	20,600
Gas Production (MMCF)	0	208,585	208,585
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	21,839	21,839

3.4.2.3 Sourdough Field

The Sourdough field is an oil accumulation in an unspecified formation that was discovered in 1994 by BP and Chevron. **Technically recoverable resources are thought to be about 100 MMBO (Table 2.6).** It is located south of the Point Thomson Unit (PTU) and adjacent to ANWR. Three exploration wells have been drilled with a successful test about 1 mile from the ANWR boundary. The accumulation is about 50 miles east of PBU and 35 miles from the Badami Pipeline, the nearest oil pipeline (OGJ, 1998). The 35-mile sales line would encounter five major river crossings and be in the coastal plain (Thomas et al., 1996).

It is assumed that the Sourdough accumulation contains about 100 MMBO of recoverable oil resources (OGJ, 1998), **which is used for this analysis**. It is assumed both gas and water injection will be used for pressure maintenance and secondary recovery, and that a total of 30 wells, injectors and producers are required to develop this accumulation.

The future oil recovery forecast is prepared using a production starting date of **2017**, a peak oil rate of 30 MBOPD, peak rate maintained for two years, an abandonment rate of about 0.2 MBOPD, and a production decline rate of 15% per year. This results in a TUR of **102,335 MBO**. The gas and water production forecasts are made using the historical gas and water production data from the Point McIntyre PA. It is assumed all gas will be used in lease operations and in secondary recovery processes.

Sourdough oil, gas, and water **production versus time forecasts are presented graphically Figure 3-46. The individual oil production forecast is tabulated in Appendix A, Table A.4.**

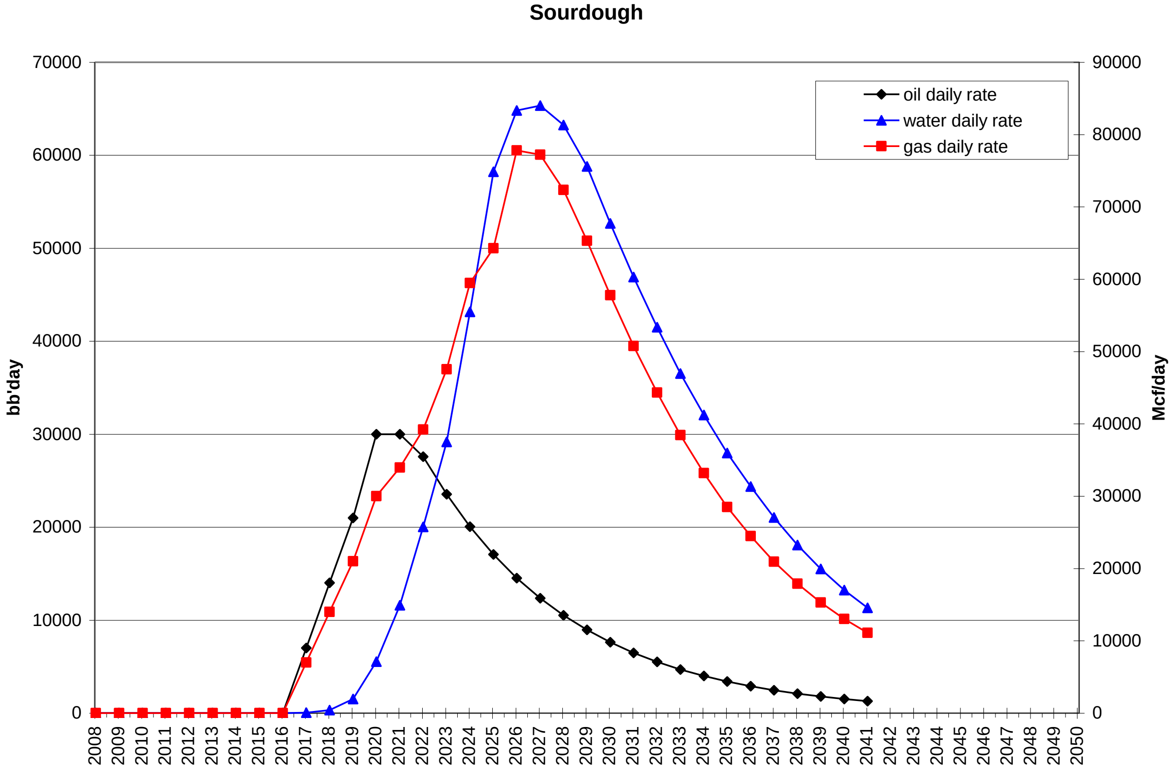

Figure 3-46. Sourdough production forecasts.

Forecasts of Sourdough future and **ultimate technically recoverable** oil, gas, and water are presented in Table 3.44.

Table 3.44. Sourdough–Forecasts of ultimate technically recoverable resources.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	0	102,335	102,335
NGL Production (MB)	0	0	0
Oil and NGLS (MB)	0	102,335	102,335
Gas Production (MMCF)	0	370,065	370,065
Gas Injection (Est.) (MMCF)	0	0	0
Water Production (MB)	0	296,861	296,861

Development of the Sourdough field are thought to be marginally economic at this time. This field could possibly be developed in conjunction with the Point Thomson field which would improve the economics.

3.4.2.4 Known Fields with Uncertain Development Timing

The Point Thomson field is a special case. It could possibly be developed as an oil and condensate development but the timeline for development is uncertain as a result of the ADNR dissolving the Unit and taking back the leases (see Section 2.3.3.1.4). This field is the subject of current litigation, which makes the timing highly uncertain. Develop of the Point Thomson field as a combined gas and petroleum liquids development is discussed in Section 3.6.2. Additional fields in the Beaufort Sea, Kuvlum and Hammerhead, are likely to remain undeveloped until infrastructure is developed for the Point Thomson field, which moves them into the long-term time frame of 2018 to 2050.

3.4.2.5 Summary of Known Fields with Near-Term Development Potential

A summary of the known fields with near-term development potential are shown in Table 3.45.

Table 3.45. ANS known fields with near-term development potential.

Pool/Field Name	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL – UNDER EVALUATION					
Sandpiper	430,000	150,088	0	150,088	0.349
Sambuca	57,500	20,600	0	20,600	0.358
Sourdough	290,000	102,335	0	102,335	0.353
Total – Fields with Short-Term Development Potential	**777,500**	**273,023**	**0**	**273,023**	**0.351**

The composite forecast of estimated **technically** recoverable production for the known fields with short-term development potential is shown on Figure 3-47.

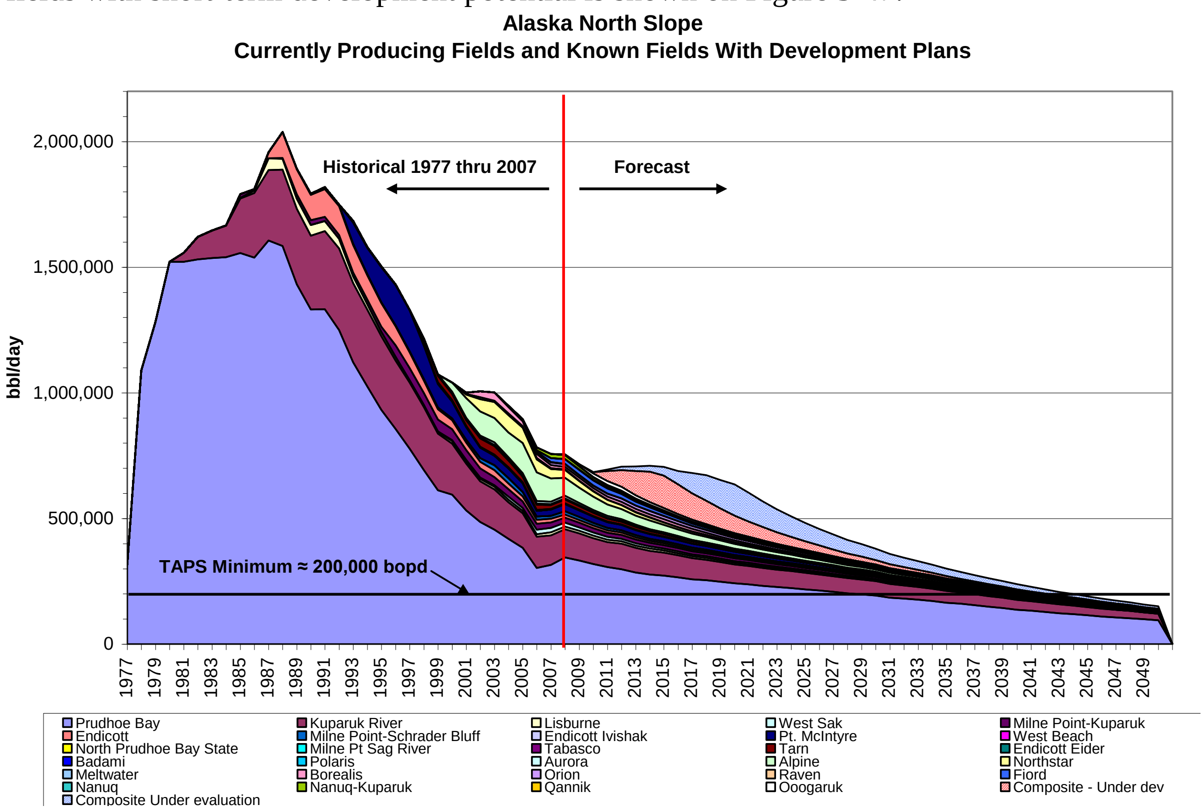

Figure 3-47. Technical production forecasts for ANS fields and pools including producing, under development, and under evaluation prospects.

3.4.3 Summary of Known Pools and Projects Under Evaluation

The Under Evaluation projects in producing pools and the know fields with near-term development potential combined would add about 0.7 BBO to the TRR and increase the total ANS TRR to total of 7.3 BBO.

3.5 Summary of Oil Recovery without Major Gas Sales

The TRR and production forecasts for the currently producing fields described in Section 3.2 are the most accurate forecasts because of existing production history. The next category, described in Section 3.3, is the known fields with pending or announced development plans that provide information in the public record that assists in developing forecasts, but these estimates are more speculative than those with production history. The most speculative projects are those under evaluation described in Section 3.4 that includes projects in producing fields and fields that have been discovered but for which there are no announced or pending development plans. The data for those fields are sparse. The composite results for OOIP, TUR, TRR, and production for each pool category through December 31, **2007** are tabulated in Table 3.46. The TRR estimates for these fields total about **6.9 BBO**.

Table 3.46. ANS fields–Currently producing fields, fields with development plans, and fields with near-term development potential.

Pool/Field Name	OOIP (MBO)	TUR (MBO)	Production 12/31/2007 (MBO)	TRR (MBO)	Recovery Factor
CURRENTLY PRODUCING FIELDS (includes under development projects in these pools)					
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	25,000,000	14,654,184	11,510,197	3,143,987	0.586
Aurora Participating Area (PA)	165,000	67,494	22,124	45,370	0.450
Borealis PA	350,000	144,420	48,307	96,113	0.413
Midnight Sun PA	60,000	22,351	16,612	5,739	0.373
Orion PA (Phase I & Phase II)	590,000	117,888	11,359	106,529	0.200
Polaris PA	303,700	78,251	6,543	71,708	0.258
Lisburne PA	3,000,000	239,345	164,945	74,400	0.080
Niakuk PA	219,000	101,630	87,326	14,304	0.464
North Prudhoe PA	12,000	2,070	2,070	0	0.173
West Beach PA	15,000	3,582	3,582	0	0.239
Point McIntyre PA	1,120,000	571,052	413,934	157,118	0.510
Raven PA	14,000	4,553	1,641	2,912	0.325
Duck Island Unit (DIU)					
Endicott PA	1,059,000	591,593	466,240	125,353	0.539
Eider PA	13,000	2,754	2,754	0	0.212

Pool/Field Name	OOIP (MBO)	TUR (MBO)	Production 12/31/2007 (MBO)	TRR (MBO)	Recovery Factor
Sag Delta North PA	18,000	8,178	8,178	0	0.454
Northstar Unit (NU)					
Northstar PA	375,000	204,585	122,390	82,195	0.546
Badami Unit (BU)	300,000	5,198	5,198	0	0.030
Kuparuk River Unit (KRU)					
Kuparuk River IPA	5,690,000	3,076,470	2,110,207	966,263	0.541
Meltwater PA	132,000	21,724	12,236	9,488	0.165
Tabasco PA	89,500	24,829	13,744	11,085	0.277
Tarn PA	525,000	161,720	86,019	75,701	0.308
West Sak PA	1,200,000	263,018	32,283	230,735	0.219
Milne Point Unit (MPU)					
Kuparuk River IPA	850,000	385,986	206,386	179,600	0.454
Sag River PA	62,000	1,849	1,849	0	0.030
Schrader Bluff PA	1,334,000	295,404	53,304	242,100	0.222
Colville River Unit (CRU)					
Alpine Oil	875,000	519,359	260,116	259,243	0.594
Fiord PA – CD3	150,000	95,418	7,364	88,054	0.636
Nanuq-Kuparuk PA –CD4	120,000	43,049	6,753	36,296	0.303
Nanuq-Nanuq Sand PA – CD4	30,000	11,240	162	11,078	0.380
Qannik-Qannik PA – CD2	79,000	21,286	55	21,231	0.269
Ooogaruk Unit (OU)	265,000	71,600	0[a]	71,600	0.270
Total – currently producing fields	**44,015,200**	**21,812,080**	**15,683,878**	**6,128,202**	**0.496**
a. Production began in 2008.					
KNOWN FIELDS WITH PENDING/ANNOUNCED DEVELOPMENT PLANS					
Colville River Unit (CRU)					
Alpine West Pool – CD5	150,000	61,342	0	61,342	0.409
Lookout Satellite – CD6	150,000	55,706	0	55,706	**0.371**
Spark Satellite – CD7	150,000	53,910	0	53,910	**0.359**
Liberty Unit (LU)	300,000	107,000	0	107,000	**0.357**
Gwydyr Bay Unit (GBU)	150,000	53,436	0	53,436	**0.356**
Nikiatchuq Unit (NU)	600,000	129,666	0	129,666	**0.216**
Total–Fields with announced or pending development plans	**1,500,000**	**453,628**	**0**	**453,628**	**0.302**

Pool/Field Name	OOIP (MBO)	TUR (MBO)	Production 12/31/2007 (MBO)	TRR (MBO)	Recovery Factor
PRODUCING FIELDS WITH PROJECTS UNDER EVALUATION					
Prudhoe Bay Unit – Orion PA	480,000	150,875	0	150,875	0.314
Prudhoe Bay Unit – Borealis PA	na	20,000	0	20,000	0.000
Prudhoe Bay Unit – Polaris PA	126,300	15,700	0	15,700	0.124
Kuparuk River Unit – West Sak	800,000	167,775	0	167,775	0.210
Colville River Unit – Alpine PA	115,000	40,000	0	40,000	0.348
Colville River Unit Alpine – Nanuq—CD4	na	4,850	0	4,850	0.000
Total for Pools and Projects Under Development	**1,521,300**	**399,200**	**0**	**399,200**	0.262
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL UNDER EVALUATION					
Sandpiper	430,000	150,088	0	150,088	0.349
Sambuca	57,500	20,600	0	20,600	0.358
Sourdough	290,000	102,335	0	102,335	0.353
Total – Fields with Near-Term Development Potential	**777,500**	**273,023**	**0**	**273,023**	**0.351**
TOTAL ALL POOLS/FIELDS	47,813,800	22,938,365	15,683,878	7,254,487	0.480

Historical oil production and future technically recoverable oil production forecasts for all the pools and fields listed in Table 3.46 are shown in Figure 3-47 above.

Unless additional fields are discovered and developed, the minimum TAPS volume of about **200,000** MBOPD could occur about **2045**. **The** recoverable resources remaining at that time, which could be as much at 1.0 BBO, could be produced but could not be transported through TAPS. New discoveries and/or resource growth, which were discussed in Section 2.5.2 and shown in Table 2.25, are required to extend the life of the ANS oil production. The long lead times of 7 to 10 years or greater required for frontier areas in the arctic means that exploration and development needs to continue or accelerate to maintain the future of the ANS oil production (EIA, 2002; EIA, 2004; Section 2.4.1). As has been described in Section 2, the construction of a gas pipeline is needed to accelerate ANS exploration. Opening of the 1002 Area of ANWR, which is a small area relative to NPRA and the OCS areas, could also increase the likelihood of major oil discoveries and rapid development.

3.6 Producing Fields with Major Gas Sales Potential

At present there are two fields, PBU and the Point Thomson field, with significant gas reserve that can supply gas to a gas sales pipeline. PBU has been producing oil and gas since 1977, with most of the gas injected back into the reservoir for EOR and recycling as shown in Figure 3-5. **The state has dissolved PTU and revoked the leases. More details on this**

matter are found in Section 2.3.3.1.4. This action causes more uncertainty about the development plans and their timing. However, for this evaluation it is assumed the lease ownership problems will be resolved to allow the development of the Point Thomson field to meet first gas sales, which is assumed to begin in 2018.

Other projects, such as DIU, Lisburne, NSU, MPU, and CRU, may supply some sales gas also. These potential sales depend on installation of economic gathering systems for these fields; therefore they are not included in this analysis. The frequently quoted estimate for ANS known recoverable hydrocarbon gas resources is 35 TCF (PN, 2005k).

The capacity of the gas pipeline has not been established and will be dependent on many currently unknown factors including the success of the open season for the nomination of gas for sale by the North Slope operators, and offtake rates allowed for gas sales from PBU and the Point Thomson field. Published information suggests it could be between 2.0 and 4.5 BCFPD (PN, 2008 and PN, 2008g).

A 35-yr project delivering 4.5 BCF/D to a gas sales pipeline on the North Slope requires a total of 57.5 TCF of hydrocarbon gas. In Section 2.4, Table 2.24, the near term (2005 to 2015) estimate of additional gas is 12 TCF and the long-term estimate (2015 to 2050) is 125 TCF for a total of 137 TCF. The assurance of a gas pipeline to transport the gas to market is needed to encourage exploration and development of sufficient gas resources to support the gas sales project. The potential life of the gas sales project could easily exceed a 35-yr life for a 4.5 BCF/D rate by many years if the potential of ANS gas resources is realized.

The estimated net hydrocarbon gas for sale from the PBU is 23.7 TCF. **Until more data are available in public records for Point Thomson field the previous estimate (Thomas et al., 2007) of** 8.0 TCF **for sale is used. This results in a total volume of sales gas of 31.7 TCF for transport in an Alaska gas pipeline (AGP) to transport gas to market from these two fields.** The estimated gas disposition is shown in Table 3.47 and Figure 3-48.

Table 3.47. PBU and Point Thomson field gas disposition.

Gas Sales Disposition	PBU	Point Thomson
OGIP	47.4 TCF	13.2 TCF
Non-recoverable gas	9.5 TCF (20.0%)	4.0 TCF (30.3%)
Lease use, local sales, and shrinkage	11.0 TCF (23.2%)	0.9 TCF (6.8%)
CO_2 in gas to conditioning plant*	3.2 TCF (6.8%)	0.3 TCF (2.3%)
Net Sales Gas to AGP	23.7 TCF (50.0%)	8.0 TCF (60.6%)
Total Sales Gas to AGP = 31.8 TCF		
*** PBU 12% CO_2; Pont Thomson field 4% CO_2**		

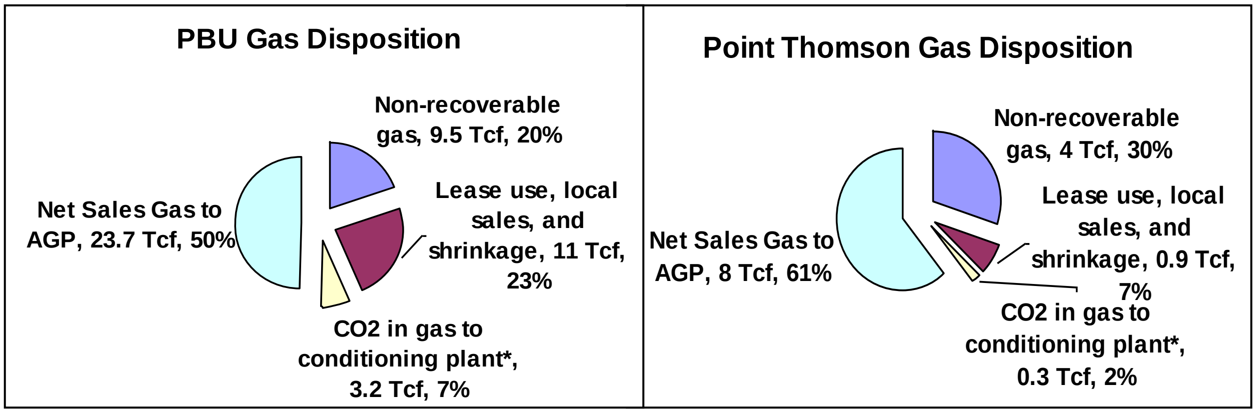

Figure 3-48. PBU and Point Thomson field gas sales disposition.

The engineering evaluations of PBU and Point Thomson with major gas sales are described in the following sections.

3.6.1 PBU – Major Gas Sales Case

The PBU has been operated since **1977** as an oil recovery project utilizing the gas cap (gas volume and pressure support) to increase the amount of liquids recovered from the oil rim. Some of the NGLs in the gas cap gas have been produced as well. This section presents an **engineering analysis** to determine the **technically recoverable resources**, both liquid and gas, with major gas sales being made.

To date, the state has not announced the volume of gas that it will allow to be sold from PBU, which makes the estimate of future performance questionable. Highly accurate estimates of oil production rates and resources under major gas sales would require a complex analysis using a full-field compositional reservoir simulation model. **Injection of water into the gas cap to assist in maintaining pressure makes the estimates more difficult. Even so,** it is most likely some reduction in oil and condensate production will occur after major gas sales commence in **2018**. **However,** the effect on ultimate recovery will be minimized because earliest gas sales are assumed to commence after more than **85%** of the TRR volumes are recovered. **In addition, the gas cap water injection process is assumed to be successful in reducing the decline in reservoir pressure.** Although beyond the scope of this study, some offsetting effect of the oil rim liquid losses could occur by recovery of additional NGLs from gas production from up-structure areas of the gas cap. Until more definitive information becomes available in the public domain **of the gas volume that will be approved by the ADNR, an estimate of the volume of reduced oil recovery will only be an *example* to illustrate what could happen. It is believed the lost oil volume could be between 150 and 300 MMB.**

The assumed impact on the oil/condensate recoveries forecasted in Section 3.2.1 is given in Table 3.48.

Table 3.48. Assumed impact of major gas sales on oil/condensate recovery in PBU.

Year	% Oil/Condensate loss
2018	0
2019	0
2020 to 2024	5
2025 to 2029	10
2030 to 2034	15
2035 to abandonment	20

This results in an estimated loss of about **230 MMB** of oil and condensate after **2018**, or a loss of about **1.6%** of TUR. The revised oil/condensate volumes are given in the Table 3.49. This table includes the PBU IPA crude oil forecast without major gas sales as described in Section 3.2.1 for reference.

Table 3.49. PBU TRR oil and gas forecast with major gas sales.

Year	% Loss	Oil w/o Gas Sales MMBOPY	Annual Oil Loss MMBOPY	Oil w Gas Sales MMBOPY	NGLs MMBPY	Total Liquid Sales MMBLPY	Wet Gas Prod. MMCFD	Gas Sales MMCFD
2008	0	103.70	0	103.70	22.23	125.93	7700	0
2009	0	100.41	0	100.41	21.13	121.55	7700	0
2010	0	96.36	0	96.36	20.08	116.44	7700	0
2011	0	93.00	0	93.00	19.05	112.06	7700	0
2012	0	90.67	0	90.67	18.10	108.77	7700	0
2013	0	86.83	0	86.83	17.19	104.03	7700	0
2014	0	84.75	0	84.75	16.35	101.11	7700	0
2015	0	84.13	0	84.13	15.51	99.65	7700	0
2016	0	82.34	0	82.34	14.75	97.09	7700	0
2017	0	80.15	0	80.15	14.02	94.17	7700	0
2018	0	79.39	0	79.39	13.32	92.71	7700	3440
2019	0	77.89	0	77.89	12.63	90.52	7700	3440
2020	5	76.32	3.82	72.51	12.01	84.51	7400	3440
2021	5	75.23	3.76	71.47	11.42	82.89	7200	3440
2022	5	73.84	3.69	70.15	10.84	80.99	6800	3440
2023	5	72.56	3.63	68.93	10.29	79.23	6500	3440
2024	5	71.61	3.58	68.03	9.78	77.81	6200	3440
2025	10	70.26	7.03	63.24	9.31	72.54	5900	3440
2026	10	68.91	6.89	62.02	8.83	70.85	5600	3440
2027	10	67.53	6.75	60.77	8.40	69.17	5300	3440
2028	10	65.77	6.58	59.20	7.96	67.15	5000	3440

Year	% Loss	Oil w/o Gas Sales MMBOPY	Annual Oil Loss MMBOPY	Oil w Gas Sales MMBOPY	NGLs MMBPY	Total Liquid Sales MMBLPY	Wet Gas Prod. MMCFD	Gas Sales MMCFD
2029	10	64.68	6.47	58.21	7.59	65.80	4700	3440
2030	15	63.22	9.48	53.74	7.23	60.96	4400	3200
2031	15	60.66	9.10	51.56	6.86	58.43	4100	2850
2032	15	59.53	8.93	50.60	6.53	57.14	3800	2650
2033	15	58.40	8.76	49.64	6.21	55.85	3500	2450
2034	15	56.94	8.54	48.40	5.84	54.24	3200	2240
2035	20	54.68	10.94	43.74	5.55	49.29	2900	2025
2036	20	53.36	10.67	42.69	5.29	47.98	2600	1800
2037	20	51.54	10.31	41.23	5.04	46.27	2300	1600
2038	20	49.60	9.92	39.68	4.78	44.46	2000	1400
2039	20	48.03	9.61	38.43	4.53	42.95	1700	1150
2040	20	45.70	9.14	36.56	4.31	40.87	1400	885
2041	20	44.46	8.89	35.57	4.09	39.65	1200	750
2042	20	42.85	8.57	34.28	3.87	38.15	1150	650
2043	20	41.25	8.25	33.00	3.65	36.65	900	0
2044	20	39.97	7.99	31.97	3.47	35.44	900	0
2045	20	38.65	7.73	30.92	3.32	34.24	900	0
2046	20	37.01	7.40	29.61	3.14	32.75	900	0
2047	20	35.88	7.18	28.70	2.99	31.70	900	0
2048	20	34.75	6.95	27.80	2.85	30.65	900	0
2049	20	33.43	6.69	26.75	2.70	29.45	900	0
2050	20	32.12	6.42	25.70	2.56	28.25	900	0
Total		**2,748.38 MMB**	**233.66 MMB**	**2,514.71 MMB**	**1,647.64 MMB**	**2,047.83 MMB**	**70,974.25 MMCF**	**23,699.4 MMCF**

Until additional information is available, it is assumed the NGL forecast after **2018** will continue at the decline rate used in the PBU forecasts in the No-Major-Gas-Sales case. The revised technical oil and gas production forecasts for the gas sales case are presented in Figure 3-49. The gas production schedule assumes that Prudhoe Bay and Point Thomson will use the available gas pipeline capacity of 4.5 BCFPD. Nomination of gas from other sources is not considered in this analysis, although it is likely that gas nominations will occur from additional fields besides Prudhoe Bay and Point Thomson for shipment in a gas pipeline.

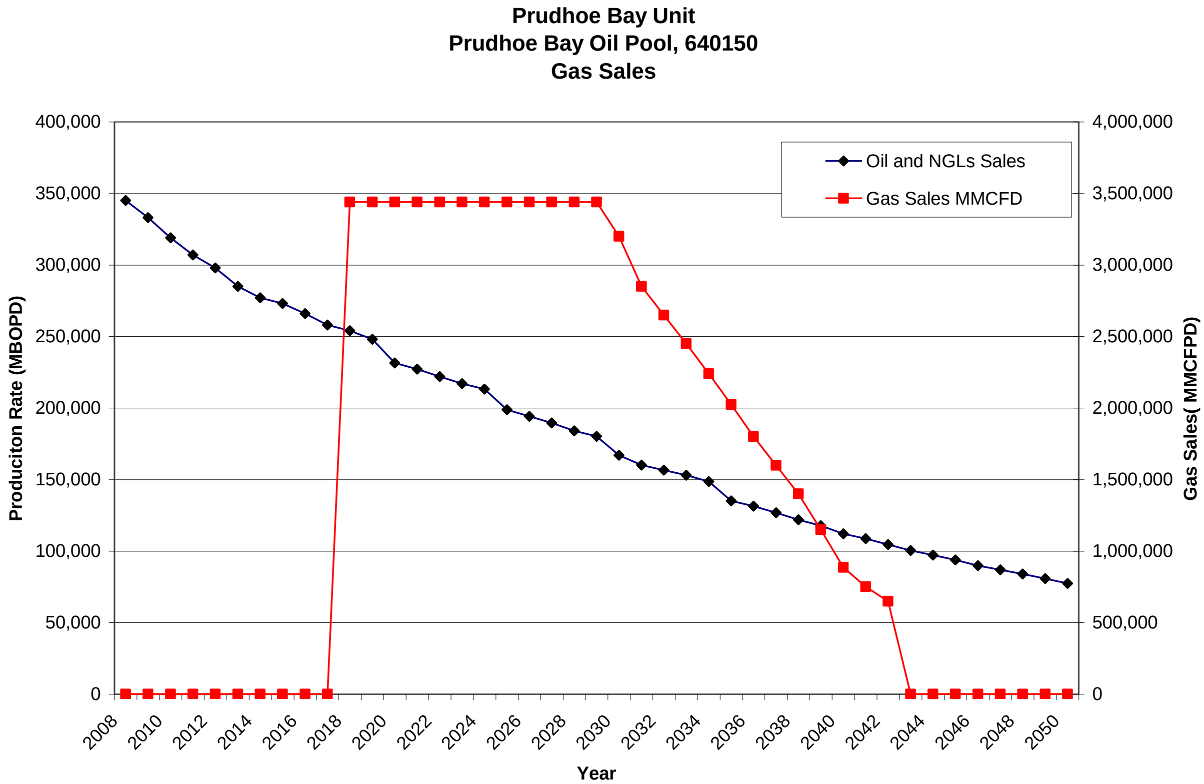

Figure 3-49. PBU oil and gas sales forecasts.

Forecasts of PBU major gas sales case of oil and gas production pool future and ultimate **technically recoverable resources as of 1/1/2007** are presented in Table 3.50.

Table 3.50. Prudhoe Bay gas sales–Forecasts of future and ultimate technically recoverable resources as of 1/1/2008 with major gas sales.

Variable	Historical	Future Technically Recoverable	Ultimate Technically Recoverable
Oil Production (MBO)	11,004,663	2,514,730	13,518,393
NGL Production (MB)	506,534	395,587	902,121
Oil and NGLS (MB)	11,510,197	2,910,317	14,420,414
Gas Production (MMCF)	56,158,952	70,974,300	127,133,252
Gas Injection (Est.) (MMCF)[1]	51,081,658	38,143,100	89,224,7580
Water Production (MB)	8,344,050	11,492,150	19,836,200
1. Assumes CO_2 extracted in gas plant is used for EOR projects and not reinjected into the gas cap.			

3.6.2 Point Thomson Field

The Point Thomson field is a high pressure condensate field located about 50 miles east of TAPS PS-1. **The former Point Thomson Unit** contains about 83,800 acres. **A recent study for the state indicated gas resources ranges of 370 to 450 MMB condensate, 250 to 400 MMBO oil, and 4.8 to 5.9 TCF gas under a 20-yr recycle project to lows of 127 to 156**

MMB condensate, 30 to 150 MMBO, and 6 to 7 TCF gas with gas sales beginning at start-up. As discussed in Section 2.3.3.1.4 the high range is considered overly optimistic and until more information is available from drilling and production tests, the estimated recoverable resources used in this report are 400 MMB condensate and oil, and 8 TCF gas (Thomas et al., 2007; PN, 2008o).

Reservoir pressure is about 10,000 pounds per square inch. The wells will be expensive and a lot of compression would be required for reinjection of gas to maintain pressure to keep the condensate from forming a separate liquid phase in the reservoir (PN, 2004l). The unit operator, ExxonMobil, reported to the state in July 2005 that a stand-alone gas cycling project was not economic leading to discussion of options for development including no gas cycling or partial gas cycling that would allow sales of gas and condensate and improve the economics of the project (PN, 2005m). The unit owners submitted a revised 22nd ~~Plan of Development~~ POD to the state on August 31, 2005, that did not include an exploration well in 2006 as required by the last unit expansion; the unit was declared in default by the state (PN, 2005n; PN, 2005o). Following a year of additional discussion and delays, Alaska officially terminated the Point Thomson leases in February 2007 and the former unit owners filed a lawsuit in Alaska Superior Court appealing the decision (PN, 2007; PN, 2007c). **The former unit operator, ExxonMobil, submitted a 23rd POD that proposed a gas cycling-condensate recovery project which was also turned down by the state (PN, 2008u). The lease-holders are continuing in discussion with the state to resolve these issues. Although the state has terminated the Point Thompson Unit, the former unit operator, ExxonMobil, announced plans to drill on it's leases at Point Thompson during the 2008-09 winter drilling season in order to delineate the reservoir and bring it on line by 2014 (PN, 2008q). ExxonMobile applied for the necessary permits to drill two wells on two leases and began mobilizing for a winter exploration program (PN, 2008r). The state has authorized processing of the permits on two "conditionally reinstated" leases providing that ExxonMobil make an unconditional funding commitment to drill and produce from these wells by 2014 (PN, 2009). Although the eventual outcome of this field is uncertain at this time, it does appear that the former unit owners are trying to find a way that will allow them to satisfy the state's requirements and hang onto the leases. It is assumed that the issues will be resolved and the Point Thomson field will come on production sometime in the foreseeable future.**

The following assumptions are made for this analysis.

1. A North Slope gas sales system will be completed by **2018**.
2. Gas will be delivered to a treating plant at the PBU area for CO_2 removal.
3. Total hydrocarbon gas recovered is assumed to be 8 TCF.
4. Point Thomson field will deliver **1,060 MMCFPD** to the gas sales pipeline, resulting in a 32-yr life.
5. Wet gas production of **1,232 MMCFD** is required before accounting for 10% for lease fuel and shrink and 4% for CO_2 content.
6. **Estimated technically recoverable condensate is 350 MMB.** Total estimated technically recoverable oil resources from the oil reservoirs are 50 MMBO.

The production forecasts of gas and liquid recoveries given in Table 3.51 were made based on these assumptions.

Table 3.51. Point Thomson oil, condensate, and gas forecasts.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBL/MMCF)	Recoverable (MBPD)			Wet Gas (MMCF/D)	Gas Sales (MMCF/D)
2018	79.8	98.3	20.0	118.3	1232	1060
2019	85.4	105.2	17.8	123.0	1232	1060
2020	85.7	105.6	15.8	121.4	1232	1060
2021	82.5	101.7	14.0	115.7	1232	1060
2022	77.2	95.1	12.5	107.6	1232	1060
2023	65.9	81.2	11.2	92.4	1232	1060
2024	56.0	69.0	9.9	78.9	1232	1060
2025	40.5	49.9	8.8	58.7	1232	1060
2026	31.3	38.6	7.9	46.5	1232	1060
2027	28.0	34.5	7.0	41.5	1232	1060
2028	23.1	28.4	6.3	34.7	1232	1060
2029	21.2	25.0	5.8	30.8	1232	1060
2030	20.0	23.6	0.0	23.6	1232	1060
2031	17.3	20.2	0.0	20.2	1232	1060
2032	15.8	16.4	0.0	16.4	1100	950
2033	15.1	13.3	0.0	13.3	1015	875
2034	12.3	11.2	0.0	11.2	940	815
2035	11.2	9.8	0.0	9.8	875	755
2036	10.3	8.3	0.0	8.3	805	695
2037	9.0	6.7	0.0	6.7	745	645
2038	7.9	5.3	0.0	5.3	675	585
2039	7.0	4.3	0.0	4.3	610	525
2040	0.0	0.0	0.0	0.0	540	465
2041	0.0	0.0	0.0	0.0	470	405
2042	0.0	0.0	0.0	0.0	420	365
TOTAL		**350 MMB**	**50 MMBO**	**400 MMB**		**8.0 TCF**

These forecasts result in TURs of 50 MMB of oil, 350 MMB of condensate, and 8 TCF of hydrocarbon gas. The forecast oil and gas production is shown in Figure 3-50.

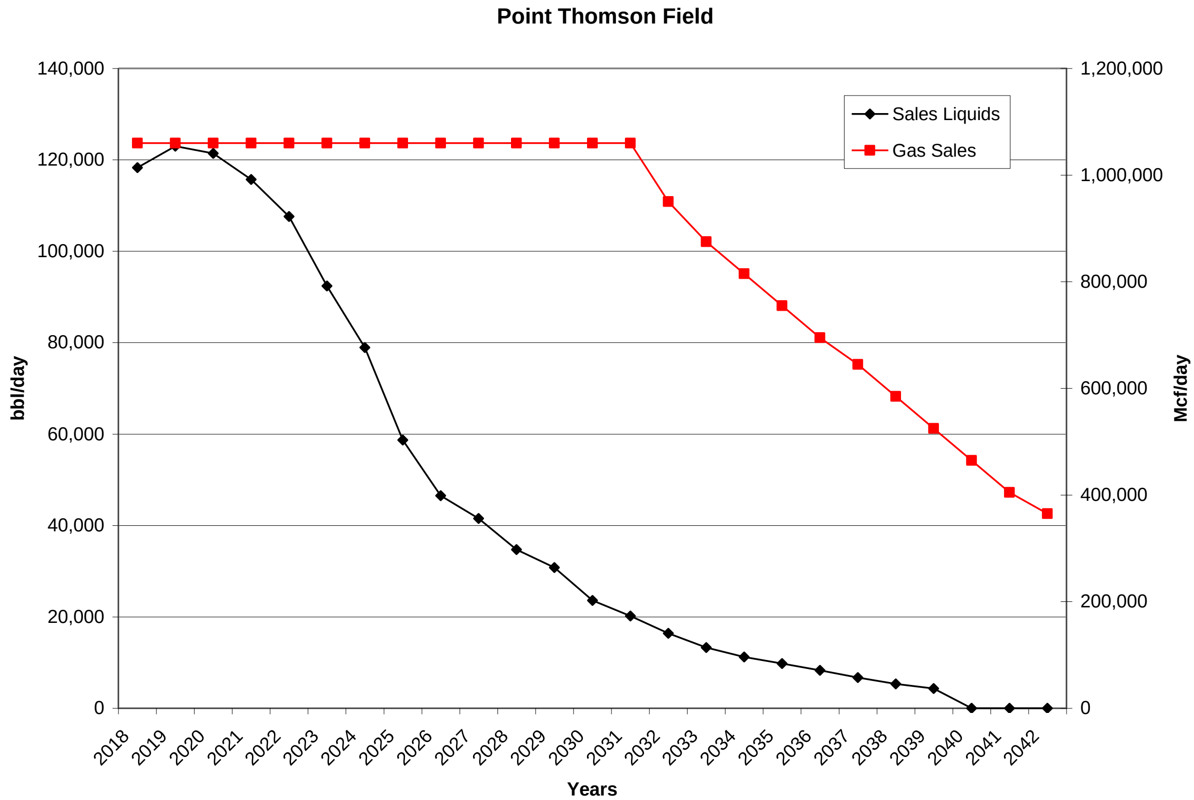

Figure 3-50. Oil and gas production from Point Thomson for major gas sales case.

3.6.3 Summary ANS Fields with Major Gas Sales

The ANS technically recoverable **oil, NGL, and condensate** production forecast for the major gas sales case is shown in Figure 3-51.[63] The TAPS minimum throughput rate of **200,000 BOPD** will still be reached by **2045** even with the addition the Point Thomson condensate and NGLs, if no additional oil is discovered and developed across the ANS that described in this section before that time.

The gas sales forecasts for PBU and Point Thomson for the assumed production plan described in this section are shown in Figure 3-52. The forecasts were developed to meet the anticipated 4.5 Bcf/day that is the anticipated initial gas sales pipeline capacity. This figure clearly shows that additional gas resources will need to be discovered and developed to support the gas sales pipeline. As discussed throughout Section 2, the gas volumes from the smaller fields are needed to support operations and EOR and are not expected to be available for sale to the gas pipeline.

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[63] The assumed 400 MMB of technically recoverable resources from Point Thompson are largely offset by the assumed loss of 233 MMBO liquids from PBU under major gas sales.

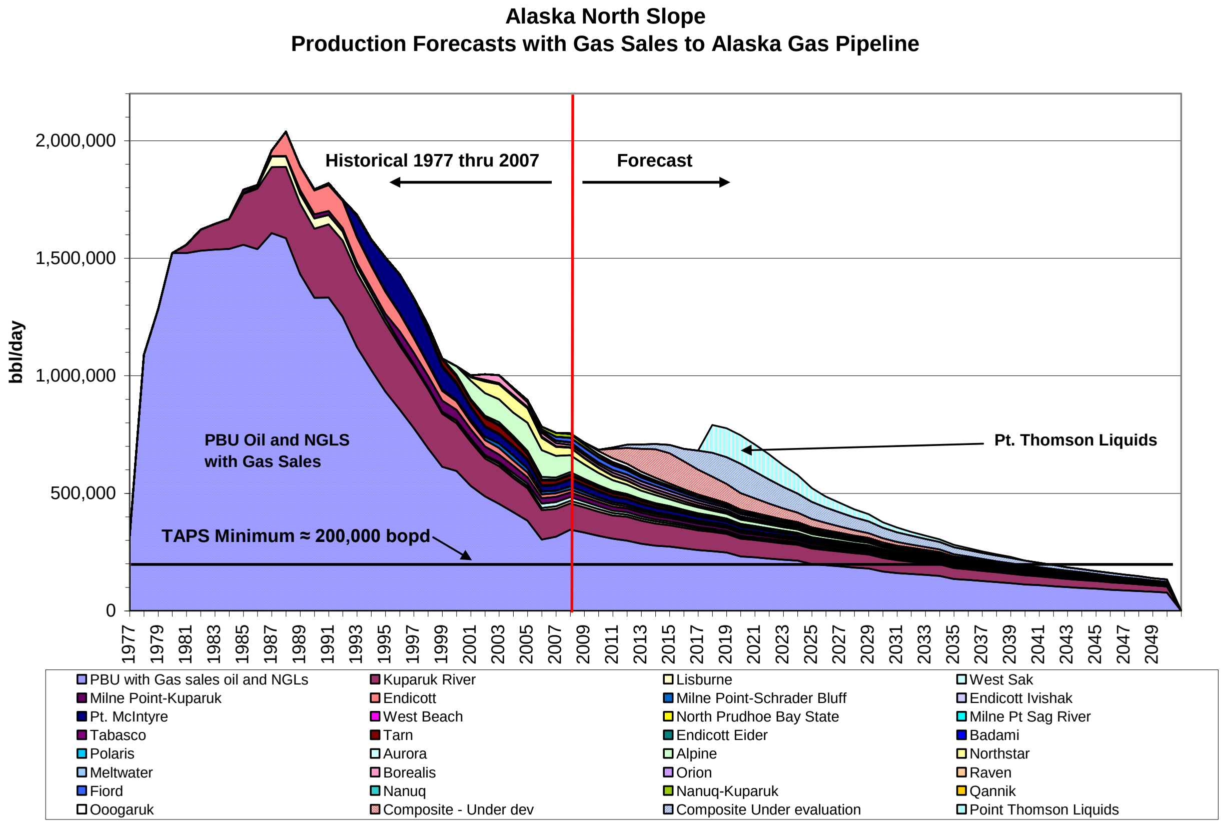

Figure 3-51. ANS production with major gas sales.

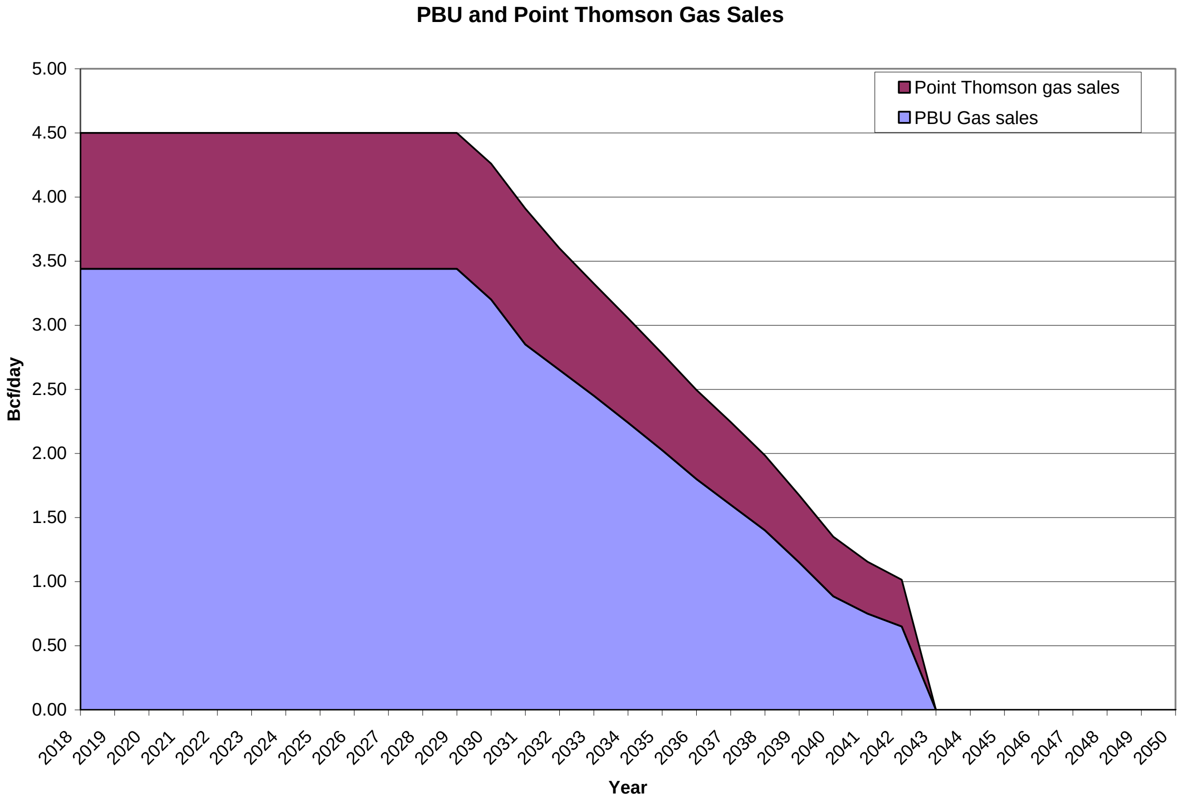

Figure 3-52. Gas sales from the Prudhoe Bay Unit and the Point Thomson field.

3.7 Summary of Engineering Evaluations

- The TRR estimated for the current producing ANS fields total **6.1 BBO** and the current estimated average recovery factor is **50%**. For the known fields with pending or announced development plans, the TRRs total **0.5 BBO**. **For the speculative project in producing fields and known fields without development plans under evaluation** the TRRs total **0.7 MMBO**. The total TRR for this grouping of fields in the no-major-gas-sales case is **7.3 BBO**.

- For the major gas sales case the Point Thomson field condensate and oil results in an addition of 400 MMBO from Point Thomson and an estimated decrease from PBU of **234 MMBO** for a total from all categories of fields including Point Thomson of about **7.5 BBO** remaining resources.

- The TAPS minimum rate of about **200,000 BOPD**, absent new developments or resources growth beyond the forecasted TRRs, will be reached in **2045**. A shutdown of TAPS would potentially strand up to about **0.9 BBO** of oil resources.

3.8 Undiscovered ANS Oil and Gas Forecasts

The potential undiscovered resources in the ANS and the adjacent Beaufort and Chukchi Seas were discussed in Section 2 and are shown to be highly significant. These potential resources total 30.85 BBO and 135.0[64] Tcf (Table 2.24) and are listed separately for five exploration provinces. These provinces are: Colville-Canning River and state Beaufort Sea, Beaufort Sea OCS, Chukchi Sea OCS, NPRA, and the 1002 Area of ANWR.

The potential resources additions, both near term and long term, of oil and gas volumes are:

- **Colville Canning/State Beaufort Sea: 3.15 MMBO and 31.00 TCF**
- **NPRA : 6.50 MMBO and 31.00 TCF**
- **Beaufort Sea – OCS : 4.95 MMBO and 21.00 TCF**
- **Chuckchi Sea – OCS : 9.50 MMBO and 50.00 TCF**
- **1002 Area of ANWAR : 6.75 MMBO and 2.00 TCF**

The most optimistic scenario for the development of the oil and gas resources include a continued favorable economic climate, stable fiscal policies, all areas open to exploration and development without major delays from lawsuits or other impediments, and the means to transport the oil and gas are maintained for the extended period. The timing and location of these potential discoveries and their subsequent development are based on the most attractive prospects being discovered and developed first.

Section 2.4 discusses the potential oil and gas fields which could be discovered in the five exploration provinces throughout the near-term and long-term time periods. There are approximately 135 oil fields and 65 gas fields cited. Because of the high number of fields and their varied geological sources, single generic oil and gas production forecasts were developed to illustrate this one scenario. Where applicable, ANS oil production history was used as a guide. The oil production used an assumed 33-year recovery life with a maximum annual production rate of 8% of ultimate recovery. The peak rate was assumed to last three years before declining at about 1% of ultimate recovery in the 33rd year. The gas forecast was made with no restrictions applied for pipeline capacity. A pronounced life of 33 years was also assumed for gas fields. A constant annual production rate of 3.75% of ultimate recovery was assumed. The peak rate was assumed to last for 19 years before production began to decline. The decline rate is about 10% per year and results in an annual recovery rate of about 1% in the 33rd year.

The oil forecasts for potential fields in each province described in Section 2 are totaled and are shown in Figure 3-53 and listed in Appendix B, Table B.1. The individual gas forecasts (non-associated only) are totaled for fields in each province and are shown in Figure 3-54 and listed in Appendix B, Table B.2.

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[64] Colville Canning/State Beaufort Sea gas volumes shown in Table 2.24 includes 2.3 TCF of associated gas. This volume is excluded from the gas volume available for sale.

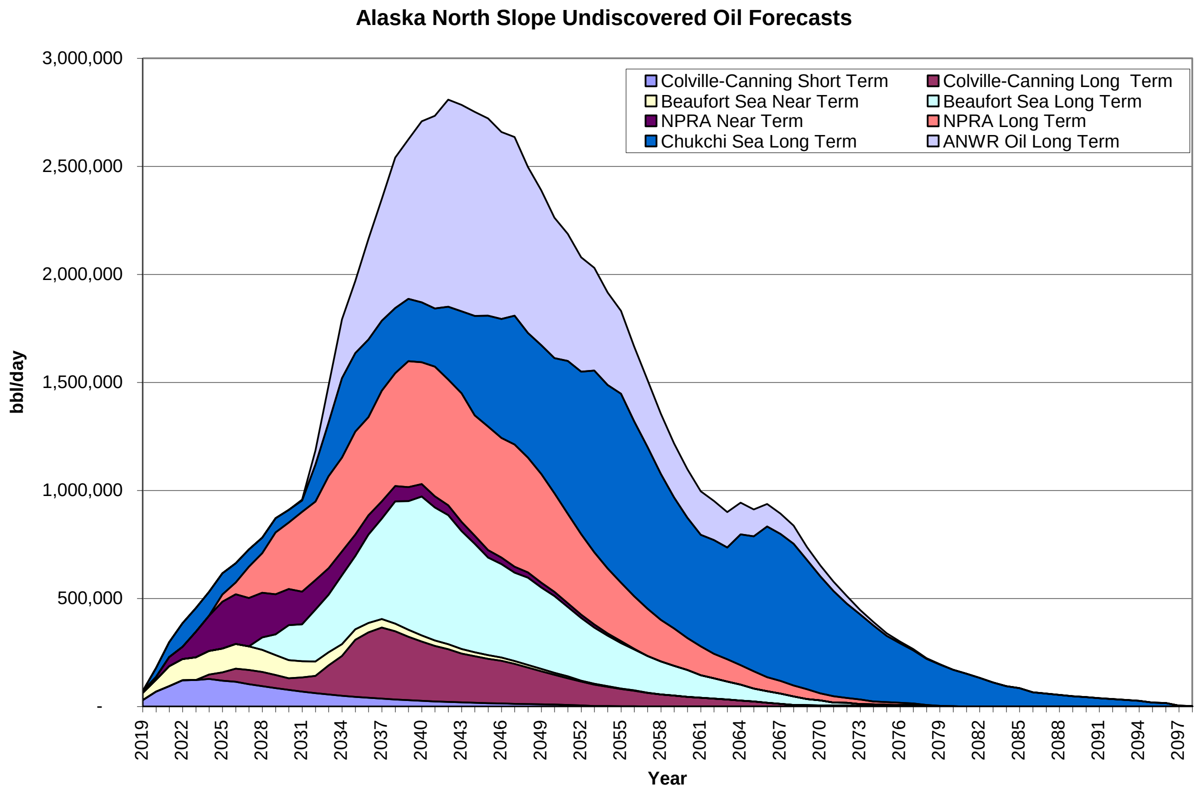


Figure 3-53. Alaska North Slope undiscovered oil forecasts.

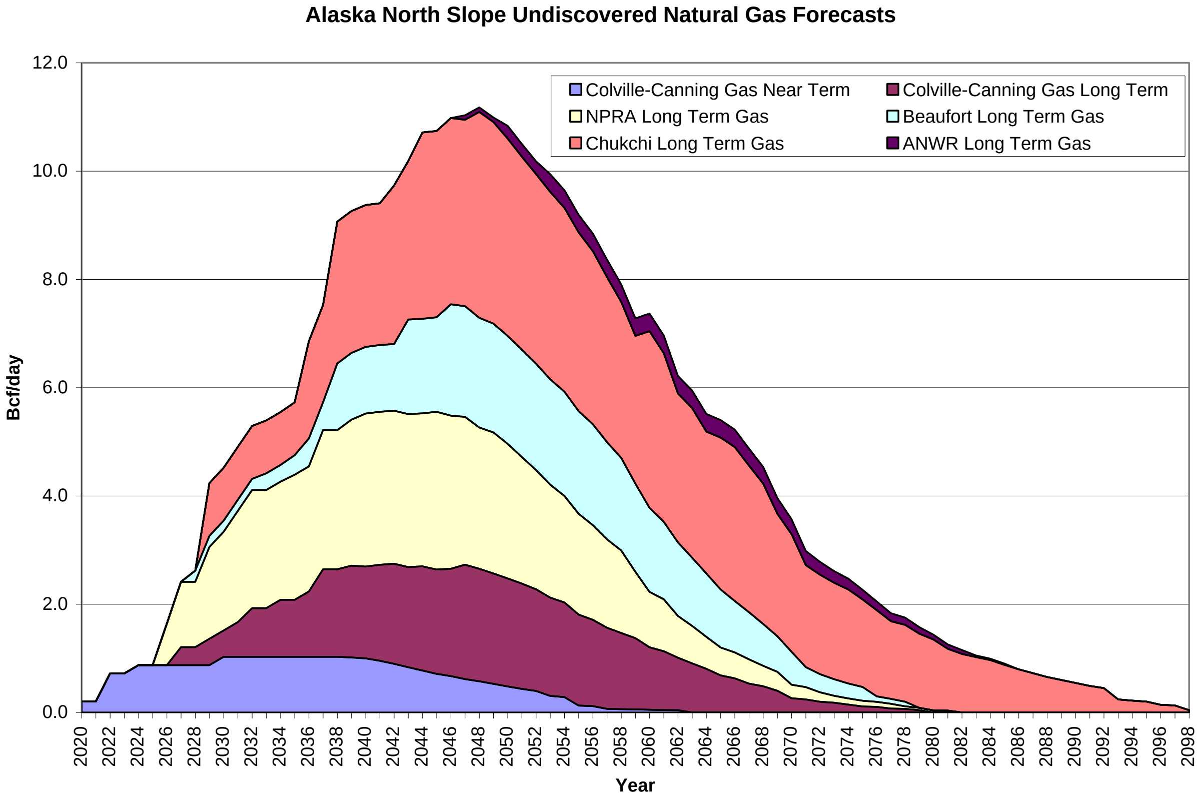


Figure 3-54. Alaska North Slope undiscovered natural gas forecasts.

Figure 3-55 and Figure 3-56 are plots showing these potential oil and gas resources added to the forecasts from producing and known fields shown in Figure 3-51 and Figure 3-52, respectively. It is clear from these figures that if the ideal scenario **were fulfilled, it could potentially result in the need to refurbish or rebuild TAPS and add capacity to the currently envisioned gas pipeline. Other scenarios are certainly possible including certain areas being off limits to exploration such as ANWR has been for decades or the exploration and development being delayed or spaced out to meet the infrastructure capacity. These scenarios are discussed below.**

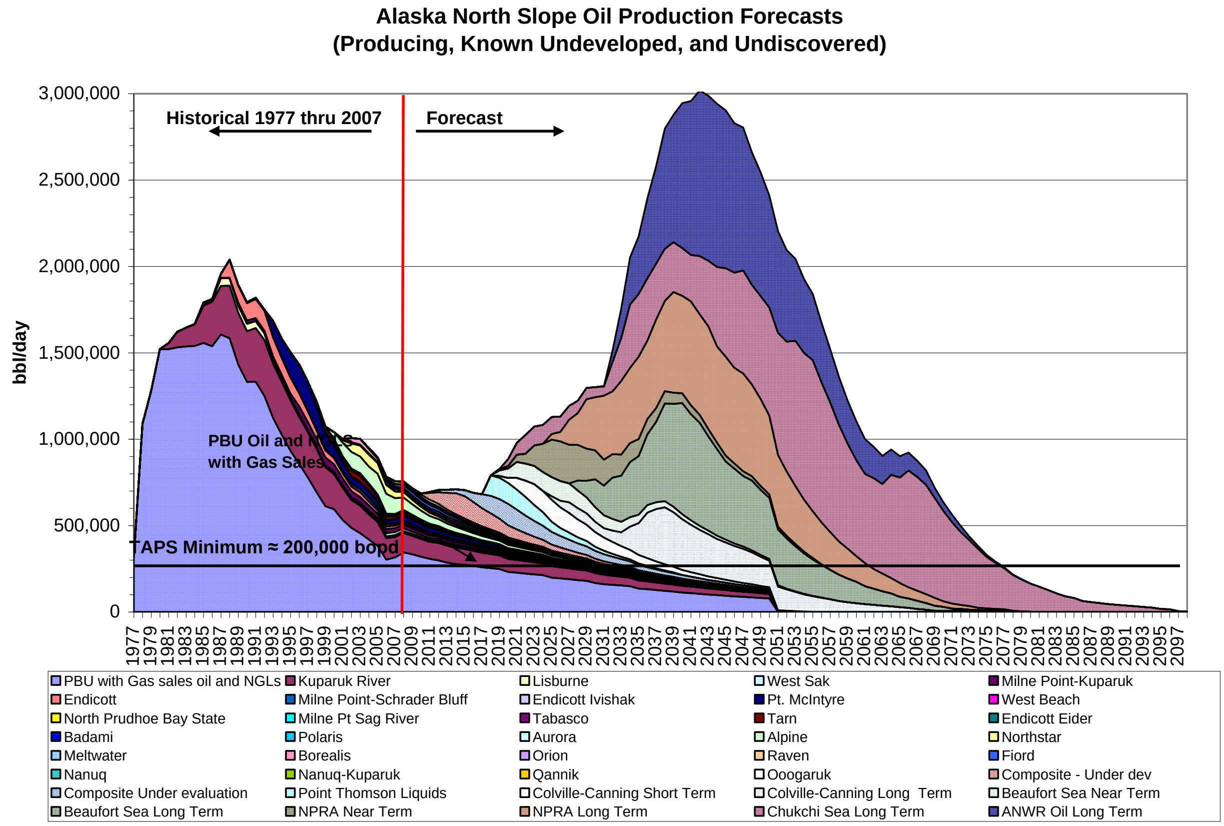


Figure 3-55. Alaska North Slope historical and forecast oil production from producing fields, known undeveloped fields, and undiscovered fields.

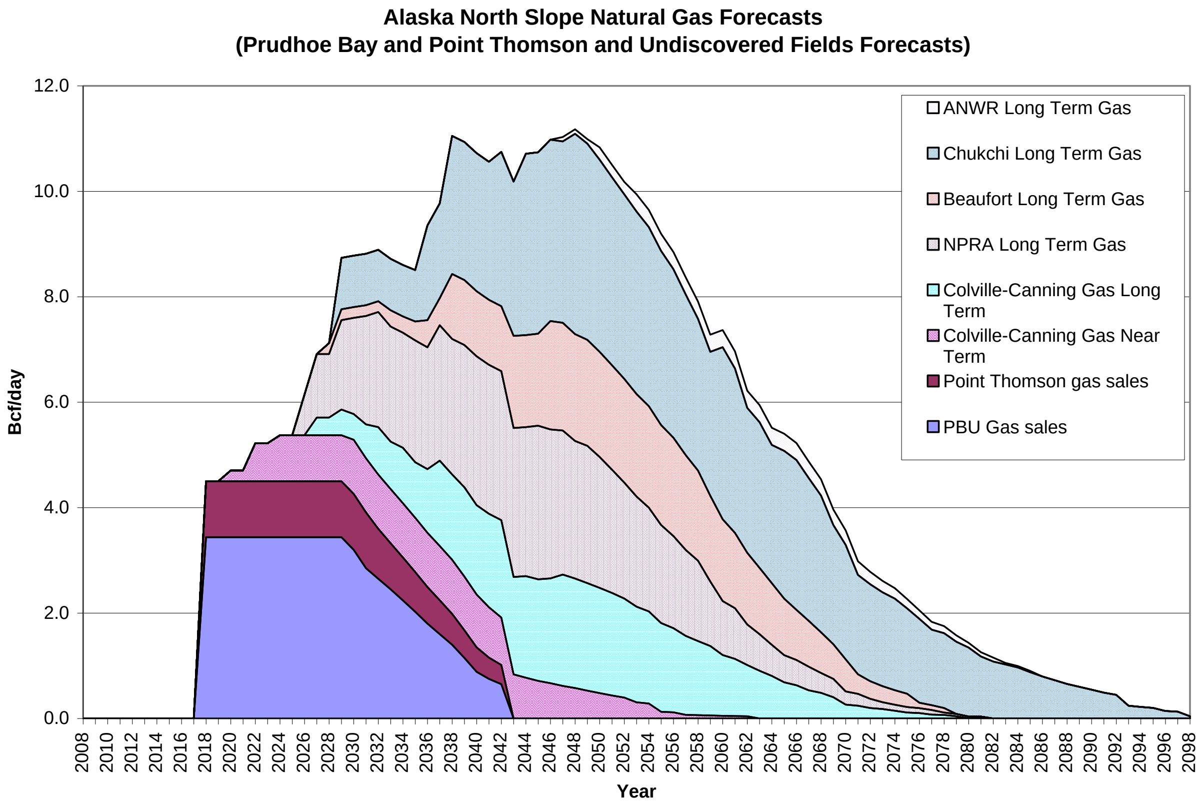
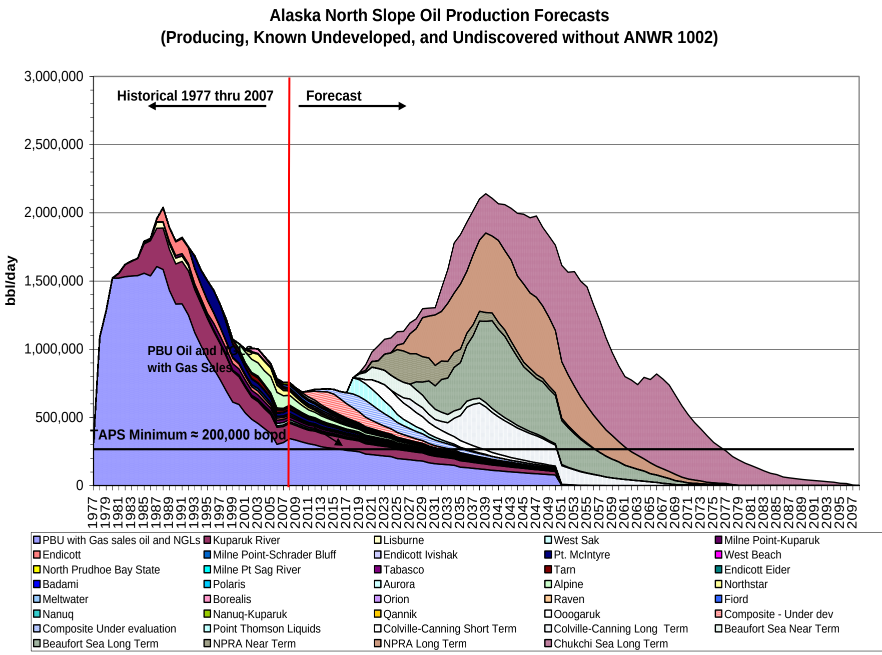


Figure 3-56. Alaska North Slope natural gas forecasts for Prudhoe Bay and Point Thomson fields and undiscovered fields.

A second possible scenario would be the permanent exclusion of ANWR 1002 area from exploration and development. This would reduce the potential oil and gas resource recovery to about 24 BBO and 133 Tcf. The forecasts for the recovery with ANWR 1002 removed are shown in Figure 3-57 for oil and gas. The oil forecasts at the peak of production would exceed the previous peak in 1988.

A third possible scenario would be the removal of both ANWR 1002 and the Chukchi Sea OCS from exploration and development. This would reduce the potential oil and gas resource recovery to about 14.6 BBO and 83.0 TCF. The remaining resource forecasts are shown in Figure 3-58.

A fourth possible scenario would be removal of the ANWR 1002, Chukchi Sea OCS and the Beaufort Sea OCS from exploration and development. This would reduce the potential resource recovery to about 9.7 BBO and 62.0 TCF. The remaining resource forecasts are shown in Figure 3-59.



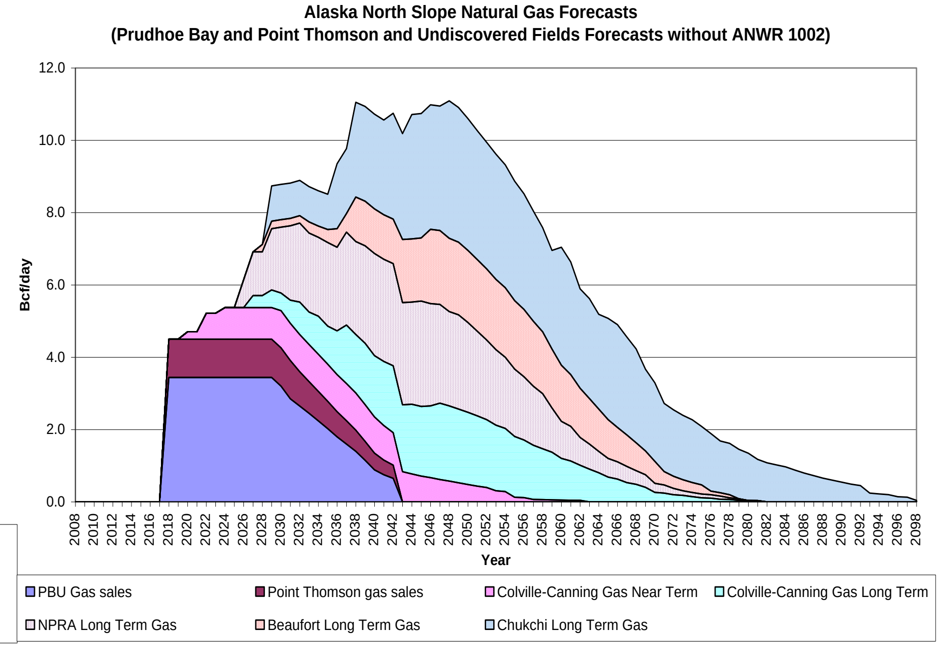
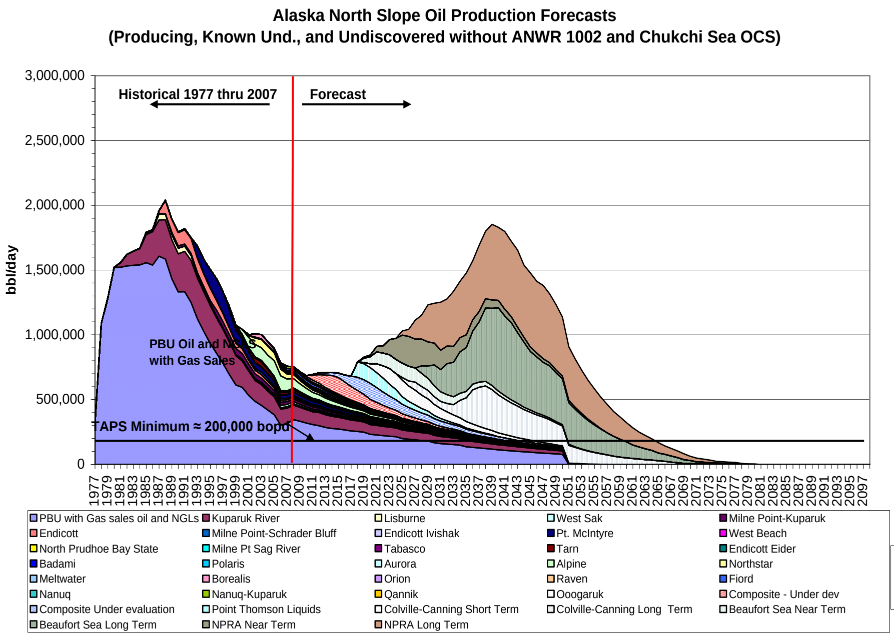


Figure 3-57. Alaska North Slope oil and gas forecasts without ANWR 1002.



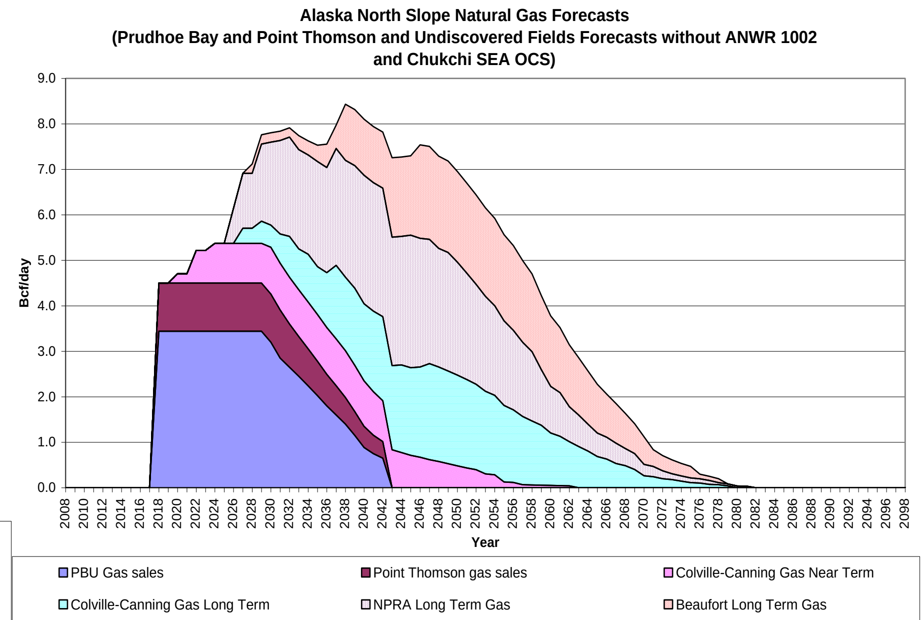


Figure 3-58. Alaska North Slope oil and gas forecasts without ANWR 1002 and Chukchi Sea OCS.

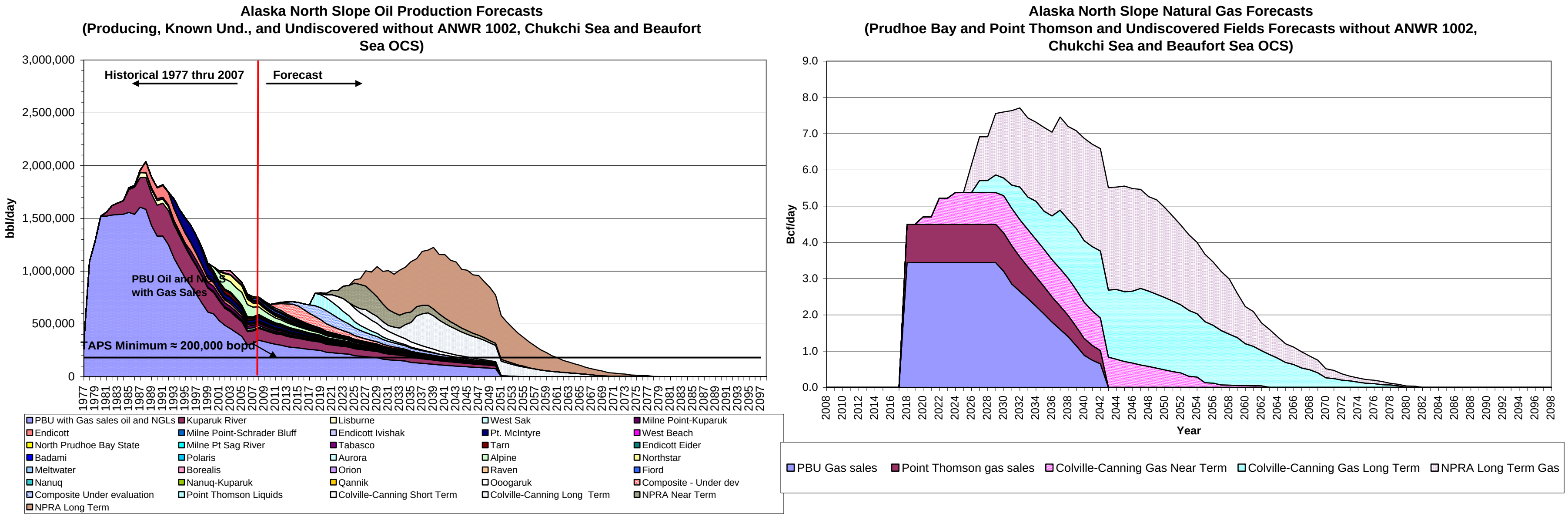


Figure 3-59. Alaska North Slope oil and gas forecasts without ANWR 1002, Chukchi Sea and Beaufort Sea OCS.

The actual scenario for the exploration and development of the potential ANS oil and gas resources will be some combination of or partial inclusion of the five exploration provinces or a slower pace of exploration and development and production into the second half of the 21st century.

3.8.1 Summary of the Undiscovered Oil and Gas Resources

This section presents a possible production forecast scenario of the large ANS potential oil and gas resources discussed in Section 2. Three alternate scenarios are also discussed. These forecasts are made with no shipping restrictions applied. The five exploration provinces were examined separately. Free access to all provinces is required for the ideal scenario.

Various implementations of these potential scenarios could result in oil and gas recoveries ranging from a high of about 31 BBO and 135 TCF gas to a minimum of about 10 BBO and 62 TCF under the most conservative assumptions.

Even the conservative scenario, if achieved, would extend the life of ANS production to 2060 or beyond. Extending the life of TAPS or its replacement would allow currently producing fields to recover economical liquids after 2045, the anticipated shut down of TAPS absent any new major discoveries. The additional recovery could be as much as 1.0 BBO.

Gas recoveries under the conservative scenario, would increase ANS gas available for sale and result in a producing life of between 50 and 55 years at an assumed delivery rate of 4.5 BCF per day.

This shows the important the oil and gas resources on the ANS could be in supplying future energy requirements for the USA.

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Appendix A

Technically Recoverable Oil Forecasts

This section contains the annual forecast production through 2050 for the fields and pools described in Section 3. The Under Evaluation forecasts are shown separately.

Table A.1. Currently Producing ANS Fields, MBOPD.

Year	Prudhoe Bay IPA	Aurora	Borealis	Midnight Sun	Orion	Polaris	Lisburne	Niakuk	Point Mcintyre
2008	345.000	9.644	10.000	1.926	10.850	4.250	10.770	4.235	28.115
2009	333.000	8.904	11.951	1.465	9.900	5.625	10.449	3.676	26.353
2010	319.000	8.260	10.899	1.180	9.800	7.840	10.364	3.238	24.616
2011	307.000	7.630	11.652	0.990	11.775	8.730	10.014	2.840	22.888
2012	298.000	7.068	11.715	0.850	13.325	8.900	9.800	2.483	21.373
2013	285.000	6.534	12.277	0.740	12.890	8.540	9.455	2.218	20.396
2014	277.000	6.041	11.948	0.660	13.030	8.400	9.101	1.993	18.911
2015	273.000	5.589	11.742	0.590	12.605	8.100	8.611	1.788	17.848
2016	266.000	5.164	10.951	0.530	12.155	8.000	8.159	1.604	16.693
2017	258.000	4.781	10.036	0.480	11.195	7.740	7.682	1.430	15.647
2018	254.000	4.425	9.151	0.445	10.705	7.180	7.260	1.318	14.805
2019	248.000	4.096	8.471	0.410	10.060	7.145	6.855	1.205	13.873
2020	242.000	3.781	7.923	0.380	9.565	6.945	6.515	1.102	13.145
2021	237.400	3.507	7.490	0.355	8.920	6.470	6.184	1.010	12.321
2022	232.000	3.233	7.071	0.330	8.450	6.005	5.827	0.959	11.701
2023	227.000	3.000	6.704	0.307	7.995	5.575	5.518	0.908	10.982
2024	223.000	2.767	6.397	0.288	7.580	5.180	5.216	0.816	10.268
2025	218.000	2.562	6.151	0.270	7.185	5.020	4.942	0.765	9.658
2026	213.000	2.370	5.893	0.255	6.910	4.985	4.671	0.713	9.097
2027	208.000	2.192	5.597	0.243	6.485	4.960	4.460	0.662	8.691
2028	202.000	2.027	5.342	0.230	6.170	4.835	4.252	0.647	8.133
2029	198.000	1.877	5.096	0.220	5.875	4.815	4.014	0.611	7.627
2030	193.000	1.726	4.841	0.210	5.605	4.745	3.808	0.583	7.122
2031	185.000	1.603	4.644	0.198	5.355	4.400	3.605	0.545	6.669
2032	181.000	1.479	4.430	0.178	5.115	4.065	3.373	0.509	6.314
2033	177.000	1.370	4.236	0.169	4.885	3.755	3.225	0.475	5.914
2034	172.000	1.274	4.093	0.160	4.675	3.465	3.079	0.445	5.611
2035	165.000	1.178	3.937	0.151	4.465	3.200	2.907	0.409	5.258
2036	160.700	1.082	3.723	0.143	4.270	2.975	2.764	0.000	4.955
2037	155.000	1.000	3.592	0.136	4.100	2.750	2.649	0.000	4.655
2038	149.000	0.932	3.444	0.129	3.925	2.555	2.479	0.000	4.403
2039	144.000	0.863	3.290	0.122	3.755	2.365	2.337	0.000	4.128
2040	137.000	0.795	3.096	0.116	3.595	2.188	2.222	0.000	3.875
2041	133.000	0.740	3.003	0.109	3.445	2.040	2.137	0.000	3.675
2042	128.000	0.685	2.885	0.103	3.300	1.905	2.025	0.000	3.475
2043	123.000	0.644	2.770	0.098	3.165	1.762	1.912	0.000	3.300
2044	119.000	0.603	2.668	0.093	3.035	1.640	1.827	0.000	3.075
2045	115.000	0.548	2.581	0.088	2.905	1.521	1.715	0.000	2.880
2046	110.000	0.521	2.482	0.084	2.775	1.408	1.658	0.000	2.710
2047	106.500	0.493	2.389	0.079	2.680	1.282	0.000	0.000	2.550
2048	103.000	0.466	2.290	0.074	2.570	1.177	0.000	0.000	2.400
2049	99.000	0.438	2.178	0.072	2.455	1.073	0.000	0.000	2.250
2050	95.000	0.411	2.074	0.067	2.361	0.949	0.000	0.000	2.100

Table A.1 (Continued). Currently Producing ANS Fields, MBOPD.

Year	Raven	Endicott	North Star	KRU Kuparuk River	Meltwater	Tabasco	Tarn	West Sak	MPU Kuparuk River
2008	1.406	13.885	31.000	112.000	2.340	3.275	15.800	17.750	20.301
2009	1.010	12.534	25.800	107.299	2.000	2.800	14.100	18.640	19.004
2010	0.771	11.764	21.499	102.800	1.730	2.425	13.300	18.450	17.899
2011	0.627	10.474	18.200	98.501	1.530	2.130	12.450	21.670	16.999
2012	0.521	10.858	15.600	101.581	1.389	1.875	12.000	21.310	16.003
2013	0.450	12.326	13.500	97.822	1.260	1.680	11.400	23.930	15.295
2014	0.390	15.118	11.800	94.175	1.150	1.520	10.555	23.730	14.696
2015	0.342	17.384	10.200	90.729	1.070	1.380	9.770	27.040	14.207
2016	0.304	19.016	8.900	87.397	1.000	1.270	8.748	24.570	13.800
2017	0.273	18.688	7.900	84.178	0.950	1.160	8.293	22.980	13.713
2018	0.248	18.512	7.000	81.485	0.870	1.060	7.904	21.580	14.120
2019	0.225	18.134	6.200	78.792	0.820	0.980	7.578	20.420	14.213
2020	0.206	16.786	5.348	75.315	0.785	0.905	7.290	19.370	14.250
2021	0.189	14.510	4.700	73.849	0.740	0.840	6.969	18.660	14.083
2022	0.173	12.715	4.150	71.488	0.700	0.780	6.542	17.920	14.030
2023	0.154	11.126	3.700	69.548	0.670	0.730	6.043	17.220	13.885
2024	0.137	9.816	3.275	67.614	0.640	0.685	5.419	16.660	13.802
2025	0.120	8.745	2.925	65.677	0.610	0.638	4.920	16.100	13.556
2026	0.107	7.858	2.640	63.964	0.590	0.600	4.437	15.540	13.379
2027	0.096	7.178	2.380	62.129	0.570	0.560	4.012	15.050	13.146
2028	0.085	6.532	2.125	60.732	0.550	0.523	3.656	14.510	12.945
2029	0.077	5.970	1.900	59.337	0.535	0.495	3.306	14.030	12.469
2030	0.068	5.515	1.710	57.512	0.515	0.463	3.088	13.610	11.855
2031	0.000	5.153	1.540	54.822	0.507	0.435	2.715	13.140	11.420
2032	0.000	4.101	1.400	52.671	0.503	0.410	2.447	12.700	10.944
2033	0.000	3.951	1.280	50.521	0.500	0.385	2.221	12.250	10.527
2034	0.000	3.800	1.175	48.647	0.495	0.365	2.018	11.800	10.076
2035	0.000	3.674	1.070	46.762	0.490	0.000	1.700	11.380	9.634
2036	0.000	3.551	0.974	45.151	0.485	0.000	1.437	10.970	9.189
2037	0.000	3.425	0.886	43.263	0.000	0.000	1.295	10.550	8.817
2038	0.000	3.301	0.806	41.932	0.000	0.000	1.177	10.190	8.419
2039	0.000	3.181	0.734	40.323	0.000	0.000	1.064	9.870	8.040
2040	0.000	3.079	0.675	38.962	0.000	0.000	0.965	9.530	7.707
2041	0.000	2.951	0.621	37.630	0.000	0.000	0.872	9.180	7.398
2042	0.000	2.849	0.571	36.548	0.000	0.000	0.703	8.920	7.112
2043	0.000	2.740	0.525	35.203	0.000	0.000	0.637	8.560	6.749
2044	0.000	2.641	0.483	33.858	0.000	0.000	0.570	8.270	6.555
2045	0.000	2.540	0.000	32.523	0.000	0.000	0.000	7.970	6.139
2046	0.000	2.449	0.000	31.178	0.000	0.000	0.000	7.720	5.873
2047	0.000	2.351	0.000	30.208	0.000	0.000	0.000	7.490	5.645
2048	0.000	2.249	0.000	29.027	0.000	0.000	0.000	7.210	5.394
2049	0.000	0.000	0.000	27.682	0.000	0.000	0.000	7.000	5.176
2050	0.000	0.000	0.000	26.463	0.000	0.000	0.000	6.710	4.960

Table A.1 (Continued). Currently Producing ANS Fields, MBOPD.

Year	Schrader Bluff	Alpine	Fiord	Nanuq Nanuq	Nanuq Kuparuk	Qannik	Oooguruk
2008	13.200	72.000	18.000	0.775	16.200	0.000	2.000
2009	12.200	61.000	20.000	1.705	12.300	0.376	8.000
2010	12.100	52.400	20.000	2.320	9.800	1.864	14.000
2011	13.250	45.501	19.600	2.695	8.000	3.288	16.200
2012	14.600	40.000	17.449	2.680	6.650	4.222	15.000
2013	17.275	36.000	15.551	2.395	5.600	3.944	13.000
2014	18.675	34.301	13.866	2.086	4.800	3.640	11.000
2015	20.740	29.000	12.364	1.835	4.150	3.366	9.600
2016	21.175	26.301	11.036	1.638	3.650	3.112	8.600
2017	21.920	25.000	9.855	1.480	3.230	2.876	7.800
2018	21.980	22.000	8.805	1.355	2.890	2.660	7.150
2019	22.620	20.099	7.868	1.245	2.570	2.460	6.600
2020	22.543	18.501	7.041	1.155	2.300	2.276	6.150
2021	22.540	17.000	6.301	1.070	2.080	2.104	5.700
2022	21.590	16.000	5.644	0.995	1.980	1.948	5.300
2023	21.020	14.800	5.060	0.920	1.700	1.802	4.900
2024	20.900	14.000	4.534	0.848	1.550	1.666	4.550
2025	21.305	12.901	4.071	0.776	1.360	1.540	4.225
2026	21.255	11.899	3.649	0.704	1.160	1.424	3.950
2027	21.305	11.000	3.279	0.520	1.000	1.318	3.750
2028	20.380	10.200	2.945	0.352	0.875	1.220	3.375
2029	19.465	9.501	2.649	0.250	0.760	1.128	3.140
2030	18.350	8.849	2.384	0.176	0.675	1.044	2.900
2031	17.555	8.299	2.151	0.150	0.594	0.966	2.700
2032	16.675	7.800	1.934	0.125	0.523	0.896	2.500
2033	15.855	7.551	1.745	0.100	0.468	0.830	2.325
2034	15.180	7.041	1.570	0.000	0.417	0.766	2.160
2035	14.520	6.800	1.419	0.000	0.373	0.708	2.000
2036	13.850	6.301	1.279	0.000	0.337	0.654	1.875
2037	13.320	5.899	1.156	0.000	0.306	0.608	1.740
2038	12.635	5.551	1.044	0.000	0.278	0.562	1.600
2039	11.995	5.249	0.945	0.000	0.250	0.520	1.500
2040	11.415	4.901	0.855	0.000	0.229	0.478	1.400
2041	10.710	4.699	0.775	0.000	0.203	0.442	1.300
2042	10.165	4.400	0.701	0.000	0.182	0.408	1.200
2043	9.290	4.214	0.636	0.000	0.000	0.378	1.110
2044	8.815	3.932	0.575	0.000	0.000	0.350	1.030
2045	7.995	3.699	0.521	0.000	0.000	0.324	0.970
2046	7.580	3.485	0.474	0.000	0.000	0.000	0.880
2047	6.940	3.321	0.430	0.000	0.000	0.000	0.825
2048	6.562	3.129	0.389	0.000	0.000	0.000	0.770
2049	6.085	2.951	0.359	0.000	0.000	0.000	0.715
2050	5.757	2.781	0.332	0.000	0.000	0.000	0.675

Table A.2. ANS Fields with Announced or Pending Development Plans, MBOPD.

Year	Alpine West CD5	Lookout	Spark	Gwydyr Bay	Liberty	Nikaitchuq
2008	0.000	0.000	0.000	0.000	0.000	0.000
2009	0.000	0.000	0.000	0.000	0.000	0.000
2010	5.500	0.000	0.000	0.000	0.000	0.000
2011	13.000	0.000	0.000	4.000	18.600	0.000
2012	13.000	0.000	0.000	8.000	30.000	8.000
2013	12.500	5.750	5.750	12.000	35.000	14.000
2014	11.250	13.700	13.700	15.000	32.340	20.000
2015	10.125	19.300	19.300	15.000	27.490	22.500
2016	9.110	16.400	16.400	14.000	23.365	25.000
2017	8.200	13.940	13.940	12.000	19.860	25.000
2018	7.380	11.850	11.850	10.200	16.880	25.000
2019	6.640	10.070	10.070	8.670	14.350	22.500
2020	5.980	8.560	8.560	7.370	12.200	20.050
2021	5.380	7.275	7.275	6.260	10.370	18.050
2022	4.840	6.185	6.185	5.320	8.815	16.250
2023	4.360	5.260	5.260	4.530	7.495	14.600
2024	3.920	4.470	4.470	3.850	6.370	13.150
2025	3.530	4.000	4.000	3.270	5.415	11.850
2026	3.175	3.230	3.230	2.780	4.600	10.650
2027	2.860	2.745	2.745	2.360	3.910	9.600
2028	2.575	2.330	2.330	2.000	3.325	8.650
2029	2.315	1.985	1.985	1.710	2.825	7.800
2030	2.085	1.685	1.685	1.450	2.400	7.000
2031	1.875	1.435	1.435	1.230	2.040	6.300
2032	1.690	1.220	1.220	1.050	1.730	5.650
2033	1.520	1.035	1.035	0.890	1.470	5.100
2034	1.365	0.880	0.880	0.760	1.250	4.600
2035	1.230	0.750	0.750	0.650	1.050	4.150
2036	1.110	0.635	0.635	0.550	0.000	3.700
2037	0.995	0.540	0.540	0.470	0.000	3.350
2038	0.895	0.460	0.460	0.400	0.000	3.000
2039	0.810	0.390	0.390	0.340	0.000	2.700
2040	0.725	0.330	0.330	0.290	0.000	2.450
2041	0.655	0.280	0.280	0.000	0.000	2.200
2042	0.590	0.240	0.240	0.000	0.000	2.000
2043	0.530	0.205	0.205	0.000	0.000	1.800
2044	0.475	0.175	0.175	0.000	0.000	1.600
2045	0.430	0.150	0.150	0.000	0.000	1.450
2046	0.000	0.125	0.125	0.000	0.000	1.300
2047	0.000	0.110	0.110	0.000	0.000	1.200
2048	0.000	0.000	0.000	0.000	0.000	1.100
2049	0.000	0.000	0.000	0.000	0.000	1.000
2050	0.000	0.000	0.000	0.000	0.000	0.950

Table A.3. Producing ANS Pools with Projects Under Evaluation, MBOPD.

Year	Borealis	Orion	Polaris	West Sak	Alpine PA	Nanuq CD4
2008	0.000	0.000	0.000	0.000	0.000	0.000
2009	0.000	0.000	0.000	0.000	0.000	0.000
2010	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.926	0.000	0.500	0.000	0.000	0.400
2012	1.247	3.550	1.800	0.000	0.000	0.800
2013	2.584	5.000	2.870	0.000	5.250	1.000
2014	3.014	10.000	3.050	0.000	7.850	1.200
2015	3.493	15.500	2.850	2.000	9.150	1.200
2016	3.411	20.000	2.640	6.850	9.150	1.200
2017	3.205	23.500	2.440	9.910	9.150	1.200
2018	2.822	25.000	2.250	18.460	9.150	1.000
2019	2.438	24.125	2.080	20.120	8.775	0.850
2020	2.137	22.435	1.925	27.200	7.850	0.720
2021	1.973	20.865	1.780	24.160	6.700	0.615
2022	1.808	19.405	1.645	21.000	5.700	0.525
2023	1.699	18.045	1.525	19.340	4.850	0.445
2024	1.589	16.780	1.415	18.200	4.125	0.375
2025	1.493	15.610	1.305	17.070	3.500	0.320
2026	1.411	14.515	1.205	16.380	2.975	0.270
2027	1.329	13.500	1.120	15.500	2.525	0.230
2028	1.260	12.555	1.040	15.040	2.175	0.195
2029	1.192	11.675	0.960	14.950	1.825	0.165
2030	1.110	10.860	0.885	14.010	1.550	0.140
2031	1.055	10.100	0.820	13.520	1.350	0.120
2032	0.986	9.390	0.745	13.150	1.100	0.105
2033	0.945	8.730	0.660	12.690	0.950	0.085
2034	0.890	8.120	0.600	12.300	0.800	0.070
2035	0.863	7.530	0.555	11.870	0.700	0.055
2036	0.822	7.025	0.505	11.450	0.600	0.000
2037	0.795	6.530	0.465	11.080	0.500	0.000
2038	0.767	6.075	0.435	10.720	0.425	0.000
2039	0.740	5.650	0.405	10.330	0.360	0.000
2040	0.715	5.255	0.375	10.010	0.300	0.000
2041	0.696	4.885	0.345	9.660	0.255	0.000
2042	0.674	4.545	0.320	9.320	0.000	0.000
2043	0.658	4.225	0.300	8.970	0.000	0.000
2044	0.638	3.930	0.280	8.630	0.000	0.000
2045	0.619	3.655	0.260	8.300	0.000	0.000
2046	0.597	3.400	0.240	8.020	0.000	0.000
2047	0.578	3.160	0.220	7.740	0.000	0.000
2048	0.559	2.940	0.200	7.470	0.000	0.000
2049	0.537	2.740	0.000	7.260	0.000	0.000
2050	0.521	2.550	0.000	6.980	0.000	0.000

Table A.4. Discovered ANS Fields with Near-term Development Potential, MBOPD.

Year	Sandpiper	Sambuca	Sourdough
2008	0.000	0.000	0.000
2009	0.000	0.000	0.000
2010	0.000	0.000	0.000
2011	0.000	4.250	0.000
2012	0.000	6.000	0.000
2013	0.000	7.000	0.000
2014	0.000	5.950	0.000
2015	5.000	5.050	0.000
2016	15.000	4.300	0.000
2017	30.000	3.655	7.000
2018	35.000	3.110	14.000
2019	40.000	2.640	21.000
2020	37.500	2.245	30.000
2021	32.800	1.910	30.000
2022	28.700	1.620	27.575
2023	25.100	1.380	23.550
2024	22.000	1.170	20.060
2025	19.200	1.000	17.070
2026	16.800	0.845	14.525
2027	14.700	0.725	12.360
2028	12.900	0.610	10.520
2029	11.300	0.520	8.950
2030	9.900	0.440	7.620
2031	8.600	0.375	6.485
2032	7.600	0.320	5.520
2033	6.600	0.270	4.695
2034	5.800	0.230	4.000
2035	5.100	0.200	3.400
2036	4.400	0.170	2.895
2037	3.900	0.140	2.460
2038	3.400	0.120	2.095
2039	3.000	0.105	1.785
2040	2.600	0.090	1.515
2041	2.300	0.000	1.290
2042	2.000	0.000	0.000
2043	0.000	0.000	0.000
2044	0.000	0.000	0.000
2045	0.000	0.000	0.000
2046	0.000	0.000	0.000
2047	0.000	0.000	0.000
2048	0.000	0.000	0.000
2049	0.000	0.000	0.000
2050	0.000	0.000	0.000

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Appendix B

ANS Regions with Undiscovered Potential Oil and Gas Resources

This section contains the annual forecast production through 2098 for the fields and pools described in Section 3.

Table B.1. ANS Regions with Undiscovered Potential Oil Resources, BOPD.

Year	Colville-Canning Short Term	Colville-Canning Long Term	Beaufort Sea Near Term	Beaufort Sea Long Term	NPRA Near Term	NPRA Long Term	Chukchi Sea Long Term	ANWR Long Term
2019	10,274	0	32,877	0	8,219	0	0	0
2020	29,452	0	54,795	0	13,699	0	41,096	0
2021	68,493	0	91,781	0	42,466	0	68,493	0
2022	94,521	0	98,630	0	56,164	0	109,589	0
2023	121,233	0	105,479	0	117,808	0	109,589	0
2024	122,603	0	109,041	0	163,562	0	109,589	0
2025	127,192	20,548	110,959	0	216,438	32,877	98,630	0
2026	119,349	38,356	113,699	0	229,726	54,795	89,041	0
2027	113,938	61,644	109,178	0	223,288	145,205	80,137	0
2028	103,664	65,753	101,849	57,534	206,507	183,562	71,918	0
2029	94,349	65,753	92,466	95,890	185,959	286,301	65,068	0
2030	85,068	60,274	83,562	161,644	167,740	307,671	58,219	0
2031	76,438	54,384	75,068	171,233	150,548	369,863	52,740	4,110
2032	68,938	65,411	67,466	239,726	135,890	363,836	170,548	66,438
2033	61,884	79,589	60,890	266,849	122,055	426,027	247,945	171,918
2034	55,719	134,247	54,521	319,178	109,932	434,384	367,123	272,603
2035	50,068	183,562	49,110	338,767	98,973	476,712	363,014	334,247
2036	44,863	263,699	43,904	409,178	88,699	454,589	359,589	464,658
2037	40,274	302,603	39,452	465,068	79,932	512,123	323,288	564,247
2038	36,027	329,247	35,493	565,548	71,562	521,712	302,055	696,027
2039	32,445	315,479	31,890	595,822	64,274	583,493	287,945	737,774
2040	29,116	293,836	28,630	643,082	57,493	564,041	276,849	838,527
2041	26,205	273,973	25,712	614,863	51,589	600,890	268,630	891,473
2042	23,521	256,781	23,082	596,849	46,397	581,986	336,712	958,390
2043	21,192	244,110	20,836	545,890	41,808	595,411	379,589	955,240
2044	19,027	226,370	18,603	501,575	37,534	557,137	459,932	944,418
2045	17,130	215,575	16,795	452,123	33,822	572,575	512,500	913,425
2046	15,322	205,288	15,068	432,534	30,315	553,301	551,130	865,000
2047	13,822	197,548	13,534	408,397	27,384	566,068	596,199	827,295
2048	12,390	184,699	12,219	403,822	24,479	531,082	576,849	768,630
2049	11,158	169,123	10,918	376,274	21,986	503,849	596,233	716,233
2050	10,048	153,164	9,932	354,329	19,822	456,397	625,616	649,514
2051	9,048	137,370	8,890	320,753	17,767	414,233	706,678	588,801
2052	6,932	123,493	3,959	290,890	15,068	372,288	752,158	529,390
2053	4,685	110,795	3,575	260,589	13,493	334,890	840,993	475,240
2054	1,712	99,726	2,699	234,507	9,726	300,685	849,418	427,562
2055	1,527	89,671	1,945	210,521	8,767	270,356	874,041	383,897
2056	630	80,795	1,753	189,329	2,808	243,205	810,000	345,486
2057	0	72,548	562	170,178	0	218,671	749,418	309,582
2058	0	62,712	0	153,014	0	192,151	674,781	278,288
2059	0	55,767	0	137,753	0	173,041	606,911	250,123
2060	0	50,164	0	123,932	0	148,205	556,233	224,986
2061	0	44,986	0	104,082	0	133,521	516,192	201,760
2062	0	40,397	0	93,740	0	113,836	526,021	181,425

Table B.1 (Continued). ANS Regions with Undiscovered Potential Oil Resources, BOPD.

Year	Colville-Canning Short Term	Colville-Canning Long Term	Beaufort Sea Near Term	Beaufort Sea Long Term	NPRA Near Term	NPRA Long Term	Chukchi Sea Long Term	ANWR Long Term
2063	0	36,356	0	82,959	0	102,534	518,158	163,212
2064	0	32,671	0	74,192	0	89,110	606,075	146,329
2065	0	27,507	0	59,493	0	80,247	624,390	123,993
2066	0	23,685	0	53,603	0	64,932	698,089	103,911
2067	0	16,836	0	47,329	0	58,438	680,438	93,795
2068	0	12,589	0	38,973	0	51,192	655,356	84,219
2069	0	7,288	0	28,151	0	46,041	598,096	59,630
2070	0	6,027	0	23,260	0	32,219	541,473	50,021
2071	0	5,411	0	13,808	0	29,000	486,692	43,781
2072	0	4,890	0	12,452	0	23,123	435,993	35,185
2073	0	4,397	0	8,630	0	20,740	393,726	20,342
2074	0	2,945	0	7,767	0	13,164	352,459	16,308
2075	0	2,137	0	6,493	0	11,767	307,055	11,884
2076	0	1,945	0	5,808	0	9,233	275,993	7,959
2077	0	1,753	0	5,315	0	8,233	245,966	5,616
2078	0	0	0	4,740	0	1,890	213,548	3,082
2079	0	0	0	1,260	0	1,685	191,384	2,247
2080	0	0	0	1,123	0	0	169,144	0
2081	0	0	0	0	0	0	151,473	0
2082	0	0	0	0	0	0	132,322	0
2083	0	0	0	0	0	0	111,651	0
2084	0	0	0	0	0	0	94,274	0
2085	0	0	0	0	0	0	84,575	0
2086	0	0	0	0	0	0	66,089	0
2087	0	0	0	0	0	0	59,212	0
2088	0	0	0	0	0	0	53,514	0
2089	0	0	0	0	0	0	47,753	0
2090	0	0	0	0	0	0	43,048	0
2091	0	0	0	0	0	0	38,671	0
2092	0	0	0	0	0	0	34,740	0
2093	0	0	0	0	0	0	30,171	0
2094	0	0	0	0	0	0	25,979	0
2095	0	0	0	0	0	0	18,342	0
2096	0	0	0	0	0	0	16,432	0
2097	0	0	0	0	0	0	4,452	0
2098	0	0	0	0	0	0	1,966	0

Table B.2. ANS Regions with Undiscovered Potential Gas Resources, BCFPD.

Year	Colville-Canning Near Term	Colville-Canning Long Term	NPRA Long Term	Beaufort Long Term	Chukchi Long Term	ANWR Long Term
2019	0.000	0.000	0.000	0.000	0.000	0.000
2020	0.205	0.000	0.000	0.000	0.000	0.000
2021	0.205	0.000	0.000	0.000	0.000	0.000
2022	0.719	0.000	0.000	0.000	0.000	0.000
2023	0.719	0.000	0.000	0.000	0.000	0.000
2024	0.873	0.000	0.000	0.000	0.000	0.000
2025	0.873	0.000	0.000	0.000	0.000	0.000
2026	0.873	0.000	0.771	0.000	0.000	0.000
2027	0.873	0.334	1.207	0.000	0.000	0.000
2028	0.873	0.334	1.207	0.205	0.000	0.000
2029	0.873	0.488	1.695	0.205	0.976	0.000
2030	1.027	0.488	1.824	0.205	0.976	0.000
2031	1.027	0.642	2.055	0.205	0.976	0.000
2032	1.027	0.899	2.183	0.205	0.976	0.000
2033	1.027	0.899	2.183	0.308	0.976	0.000
2034	1.027	1.053	2.183	0.308	0.976	0.000
2035	1.027	1.053	2.312	0.360	0.976	0.000
2036	1.027	1.207	2.312	0.514	1.798	0.000
2037	1.027	1.618	2.568	0.514	1.798	0.000
2038	1.027	1.618	2.568	1.233	2.620	0.000
2039	1.016	1.695	2.697	1.233	2.620	0.000
2040	1.000	1.695	2.825	1.233	2.620	0.000
2041	0.956	1.772	2.825	1.233	2.620	0.000
2042	0.899	1.849	2.825	1.233	2.928	0.000
2043	0.836	1.849	2.825	1.747	2.928	0.000
2044	0.774	1.926	2.825	1.747	3.442	0.000
2045	0.714	1.926	2.913	1.747	3.442	0.000
2046	0.670	1.986	2.828	2.055	3.442	0.000
2047	0.617	2.113	2.731	2.044	3.442	0.084
2048	0.577	2.078	2.609	2.027	3.801	0.084
2049	0.529	2.039	2.605	2.011	3.723	0.084
2050	0.481	1.996	2.483	1.995	3.645	0.235
2051	0.436	1.945	2.340	1.981	3.566	0.235
2052	0.397	1.879	2.200	1.967	3.501	0.235
2053	0.307	1.815	2.088	1.945	3.462	0.326
2054	0.285	1.747	1.968	1.924	3.397	0.326
2055	0.128	1.682	1.861	1.895	3.304	0.326
2056	0.117	1.596	1.748	1.863	3.197	0.326
2057	0.068	1.499	1.631	1.796	3.048	0.326
2058	0.062	1.406	1.524	1.710	2.880	0.326
2059	0.056	1.318	1.225	1.628	2.728	0.326
2060	0.051	1.153	1.024	1.552	3.264	0.326
2061	0.046	1.085	0.960	1.430	3.117	0.326
2062	0.042	0.971	0.769	1.360	2.749	0.326

Table B.2 (Continued). ANS Regions with Undiscovered Potential Gas Resources, BCFPD.

Year	Colville-Canning Near Term	Colville-Canning Long Term	NPRA Long Term	Beaufort Long Term	Chukchi Long Term	ANWR Long Term
2063	0.000	0.906	0.693	1.259	2.762	0.326
2064	0.000	0.807	0.590	1.170	2.621	0.326
2065	0.000	0.686	0.515	1.072	2.802	0.326
2066	0.000	0.631	0.479	0.950	2.844	0.321
2067	0.000	0.534	0.447	0.871	2.708	0.314
2068	0.000	0.485	0.378	0.772	2.595	0.308
2069	0.000	0.402	0.348	0.658	2.260	0.293
2070	0.000	0.264	0.250	0.608	2.172	0.275
2071	0.000	0.242	0.226	0.370	1.885	0.260
2072	0.000	0.198	0.174	0.335	1.838	0.237
2073	0.000	0.180	0.128	0.305	1.781	0.216
2074	0.000	0.145	0.115	0.275	1.737	0.199
2075	0.000	0.112	0.104	0.253	1.617	0.178
2076	0.000	0.103	0.095	0.102	1.590	0.161
2077	0.000	0.074	0.087	0.091	1.433	0.149
2078	0.000	0.067	0.047	0.085	1.420	0.134
2079	0.000	0.042	0.042	0.000	1.370	0.122
2080	0.000	0.000	0.038	0.000	1.308	0.090
2081	0.000	0.000	0.035	0.000	1.142	0.081
2082	0.000	0.000	0.000	0.000	1.080	0.074
2083	0.000	0.000	0.000	0.000	1.023	0.030
2084	0.000	0.000	0.000	0.000	0.968	0.027
2085	0.000	0.000	0.000	0.000	0.878	0.025
2086	0.000	0.000	0.000	0.000	0.797	0.000
2087	0.000	0.000	0.000	0.000	0.725	0.000
2088	0.000	0.000	0.000	0.000	0.655	0.000
2089	0.000	0.000	0.000	0.000	0.600	0.000
2090	0.000	0.000	0.000	0.000	0.545	0.000
2091	0.000	0.000	0.000	0.000	0.490	0.000
2092	0.000	0.000	0.000	0.000	0.449	0.000
2093	0.000	0.000	0.000	0.000	0.242	0.000
2094	0.000	0.000	0.000	0.000	0.219	0.000
2095	0.000	0.000	0.000	0.000	0.200	0.000
2096	0.000	0.000	0.000	0.000	0.142	0.000
2097	0.000	0.000	0.000	0.000	0.130	0.000
2098	0.000	0.000	0.000	0.000	0.042	0.000

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