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

DOE/NETL-2007/1280

Summary Report

August 2007

Disclaimer

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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 depicted in a light green tint and gas fields with a 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 this Alaska North Slope oil and gas resource assessment. The purpose of the assessment is 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.

An Advisory Committee was formed to review plans and provide input to the assessment. The committee members are listed below.

U.S Department of Energy, NETL, Arctic Energy Office: Brent Sheets
U.S. Department of Interior, Office of the Secretary: Michael Baffrey
U.S. Department of Interior, Bureau of Land Management: Colleen McCarthy & Bob Fisk
U.S. Department of Interior, Minerals Management Service: Rance Wall & Tom Murrell
U.S Department of Interior, U.S. Geological Survey: Ken Bird
Alaska Department of Natural Resources, Division of Oil and Gas: Tim Ryherd & William Nebesky
Alaska Department of Revenue: Michael Williams
Alaska Oil and Gas Conservation Commission: Robert Crandall & Tom Maunder

The Summary Report, DOE/NETL-2007/1280 is intended to be a stand-alone report and summarizes the results of the detailed analysis contained in the Full Report, DOE/NETL-2007/1279. The Full Report consists of four main chapters: Chapter 1–Introduction; Chapter 2–Geological Assessment of the Alaska North Slope; Chapter 3–Engineering and Economic Assessment; and Chapter 4–Environmental and Regulatory Issues.

The Alaska Petroleum Production Tax that passed the Alaska Legislature on August 11, 2006 and was signed into law by the governor of Alaska on August 19, 2006 is not analyzed in the report.

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ALASKA NORTH SLOPE OIL AND GAS
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Abstract

This report presents summary of a detailed assessment and analysis of the oil and gas resources on Alaska's North Slope. The details are available in full report entitled *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline?*, DOE/NETL-2007/1279, May 2007. The assessment covers the geographical region of Arctic Alaska 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 includes: (a) a review of the regional geology relative to oil and gas resources; (b) an engineering and economic 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; (d) estimates of the minimum economic field size for developments in each of the exploration areas; and (e) a discussion of economic value of sharing facilities when developing new resources.

The future projections were viewed from two perspectives, near term (2005 to 2015) and long term (2015 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 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 soon, (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 Alaska North Slope natural gas pipeline is operational by 2015 to 2016, (5) oil and gas prices remain near the current high values, 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.

Key findings are summarized below:

- Oil 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 below 900,000 barrels per day in 2005, but still represents about 17% 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 (The Northstar Unit produces from both state and federal waters in the Beaufort Sea). Through 2004, Alaska North Slope oil fields had produced 15 billion barrels of oil, or about 70% of the estimated economically recoverable oil from the currently developed fields. The remaining economically recoverable oil from these fields is between 6 and 7 billion barrels.

- Discovered 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 is not 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 a drilling density of approximately one exploration well per 22 square miles. Only forty-five 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 2015, 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, 2015 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 continued high oil and gas prices, 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 TAPS 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 6.4 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. A reserve decline in the Prudhoe Bay field is estimated to be about 138 million barrels of oil, resulting in an estimate of about 6.8 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 Trans Alaska Pipeline System's (TAPS) minimum flow rate of about 300,000 barrels of oil per day will be reached in 2025, 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 and extend the life of TAPS for about one year to 2026. A shut down 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 10.4 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 construction of a 4.5 billion cubic feet per day Alaska gas pipeline by 2015 and the ability to sell gas from the Prudhoe Bay and Point Thomson fields will nearly double the revenue to the stakeholders (state of Alaska, federal government, and industry). New oil and gas discoveries catalyzed by the gas pipeline will further increase revenues.

- The minimum economic field size estimates and 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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ALASKA NORTH SLOPE OIL AND GAS:
A Promising Future or an Area in Decline?

S.1 Purpose

The purpose of this report is to provide a detailed assessment and analysis of Alaska North Slope (ANS) oil and gas resources and the interrelated technical, economic, and environmental factors controlling development of those resources. 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 S.1.

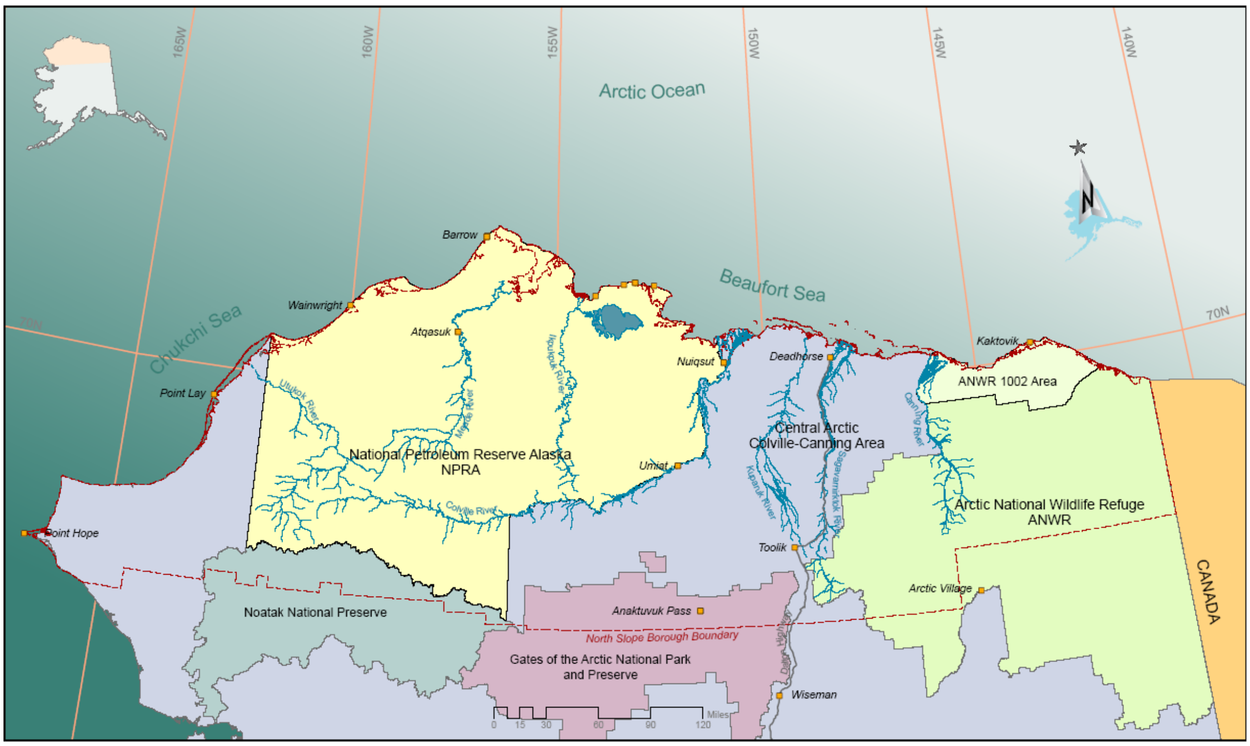

Figure S.1 The North Slope, Alaska and adjacent Chukchi and Beaufort Seas. (Map by Mapmakers Alaska, Palmer, AK)

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 economic potential 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. The effects of infrastructure, access to infrastructure, environmental regulations, advanced technology development, and development of a gas pipeline on the future viability of ANS oil and gas production are described.

S.2 Introduction

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 S.2.[1] Successful exploration has progressed into eastern NPRA and has lead to pending development of three satellites fields near the Colville River Unit.

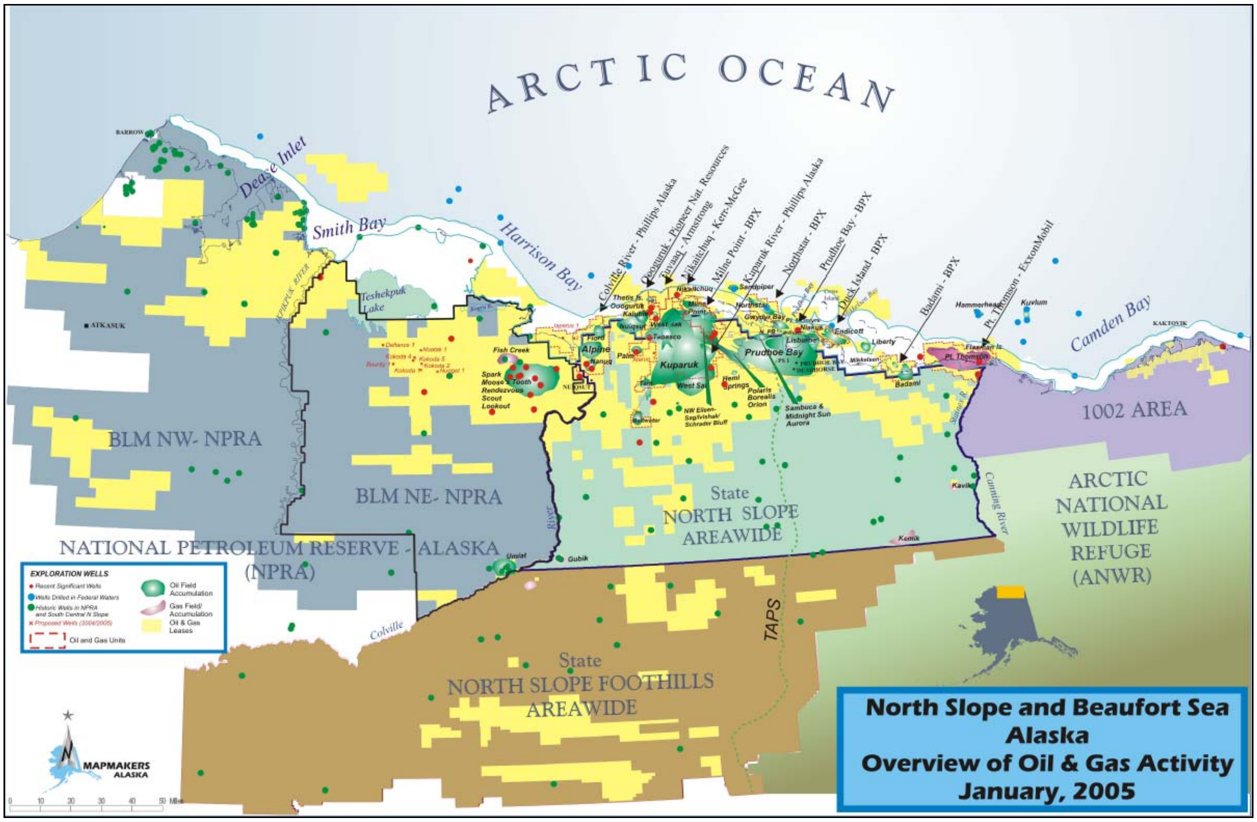

Figure S.2. North Slope Oil and Gas Activity and Discoveries.

S.2.1 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 S.3. Since 1978, ANS fields, driven

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

by the Prudhoe Bay and Kuparuk oil fields, have comprised up to 25% of U.S. domestic crude oil production and currently comprise about 17% of U.S. domestic production. The current production rate is less than 900,000 barrels of oil per day (BOPD) or about 45% of the peak production levels of the late 1980s.

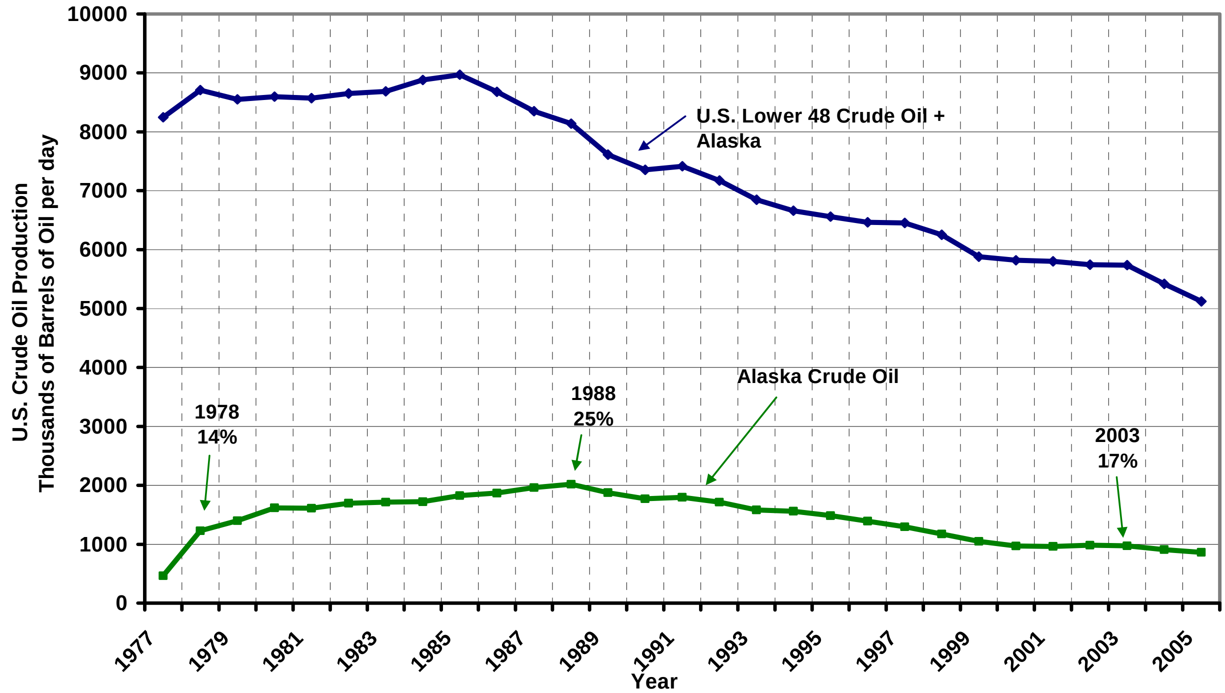

Figure S.3. Lower 48 and Alaska crude oil production (Energy Information Agency, U.S. Crude Oil Supply, www.eia.doe.gov).

The ANS production decline has been dominated by the continuing decline of Prudhoe Bay production as shown in Figure S.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 could reach the estimated minimum Trans Alaska Pipeline System (TAPS) throughput rate of about 300,000 BOPD by 2025 as shown on Figure S.4. This minimum flow rate would be achieved by reducing the number of pumps at the four required TAPS pump stations (PS) to one pump per station at PS 1, 3, 4, and 9. TAPS is currently configured with three pumps at these four stations, sufficient to support a throughput of 1.14 million barrels of oil per day (MMBOPD) (Alyeska, 2004). Throughput could be increased to about 2 MMBOPD by adding addition pump skids and returning additional pump stations to service. At the peak production rates in 1988, 10 pump stations were operating. 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.

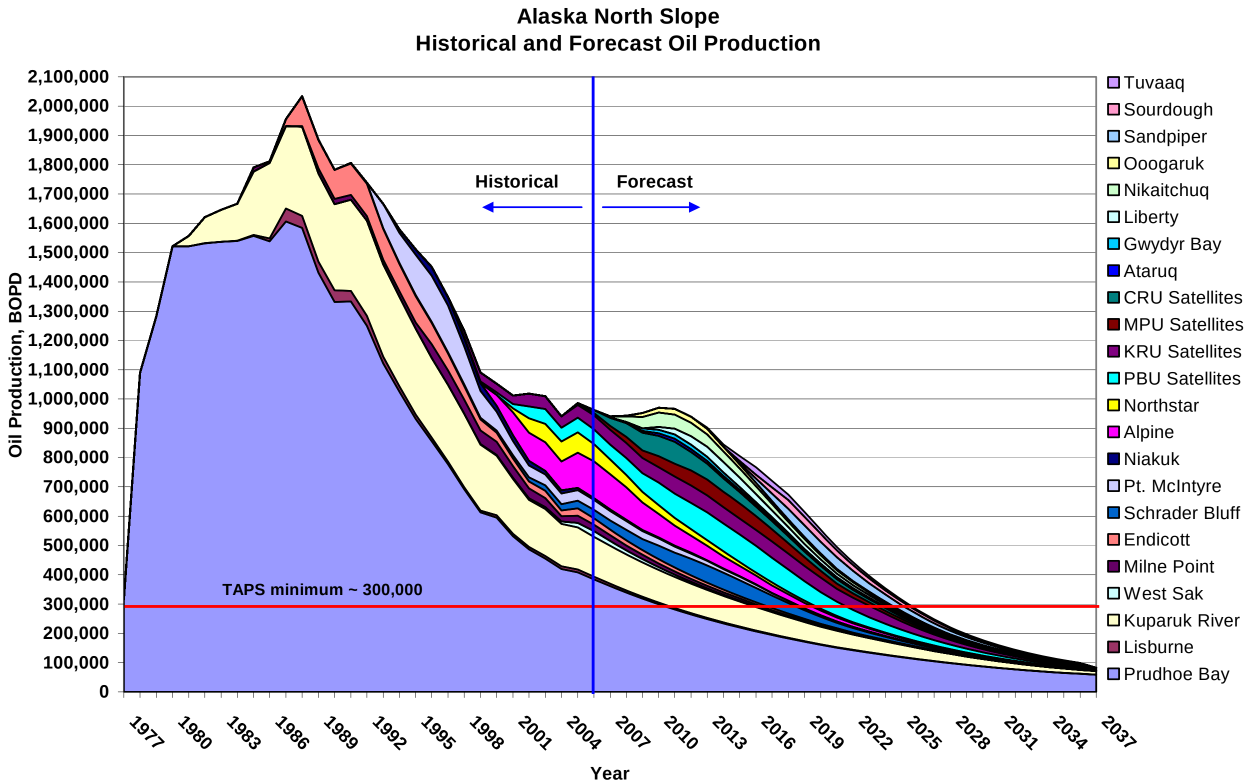

Figure S.4. Alaska North Slope historical and forecast production–without Major Gas Sales. (ADOG, 2004; see full report, Section 3.3, 3.4 & 3.5)

S.2.2 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 report it is assumed that a gas pipeline will be in place by 2015 to 2016 and this will stimulate aggressive exploration for natural gas and oil.

Exportable hydrocarbon natural gas reserves (produced gas less 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 (BCFPD), of which about 7.2 BCFPD is reinjected. Natural gas re-injection has had a positive impact on recovery efficiency in PBU and in other producing fields. In addition, miscible injectant (MI), a combination of natural gas and natural gas liquids (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 deliver ANS gas to market. Carbon dioxide (CO_2) 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 multi-lateral 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 S.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 reserves estimated for NPRA. 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 has been dominated by a few major oil companies (BP, ConocoPhillips, and ExxonMobil), or their predecessors, which 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, recent lease sales in NPRA, and on state lands, suggest independent operators and major operators other than the current big three companies may become important in the future and the decision-making process could change significantly. The increase in the number of companies will potentially increase the amount of investment that can occur on the ANS.

S.3 Scope and Approach

The **Geological Assessment** 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 addresses two time frames **– near term** (2005 to 2015) and **long term** (2015 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 2015 to 2016. 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 economically 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, until recently.

Because the ANS contains large quantities of coal, the potential for CBNG production is significant. A 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 and others, 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. One major project within hydrates research program is aimed at ANS gas hydrate reservoir characterization. According to MMS and USGS estimates (Petroleum News, 2005a; 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 and Economic Evaluation** contains the engineering and economic evaluation of the ANS oil and gas producing region. The economic analysis uses discounted cash flow analysis, together with the geologic and engineering findings and estimates the revenue generated for industry, the state of Alaska, and the federal government from ANS oil and gas production. A summary description of individual pool production history, field and reservoir performance observations, production forecasts, economic analyses for each pool and field, and estimated ultimate recovery (EUR) are presented for a range of oil and natural gas prices. This section is divided into currently producing fields, fields with announced development plans, known fields with potential for development in the near future, and minimum economic oil and gas field sizes (MEFS) for the different regions. A separate analysis is provided for major gas sales starting in 2015 from the Prudhoe Bay and Point Thomson fields.

Environmental and Regulatory Issues, describes: (a) the regulatory, land management, resource agencies, and local governments agencies and their respective functions; (b) the acts, regulations, and permits that control oil and gas development; (c) the lease sale and regulatory permitting process; (d) the environmental issues, impacts, and mitigation measures currently in place; and (e) evaluates the effects of changes in technology and practices on ANS exploration and development. The costs of environmental regulations and compliance are discussed and issues that could present major road blocks to future exploration and development are described.

S.4 Geological Assessment

The ANS regions analyzed include the Central-Arctic (the region between the Colville and Canning Rivers), NPRA, 1002 Area of ANWR, the Beaufort Sea OCS, and the Chukchi Sea OCS. The developed producing area is the northern portion of the Central Arctic and adjacent state waters including the federal portion of the Northstar field.

The history of oil and gas exploration on the ANS is intimately inter-related with its geology. Many of the early geological investigations centered on the oil seeps in areas now known as NPRA and ANWR. The geology underlying the adjacent shelfal waters of the Beaufort and Chukchi Seas is an extension of that seen onshore ANS and these areas are considered to have the same geological history and associated petroleum systems.

S.4.1 Geologic Framework

The geological evolution and petroleum geology of the area are summarized in terms of the major Phanerozoic tectonic events and the resulting stratigraphic megasequences (Lerand, 1973; Hubbard and others, 1987). There are four megasequences (1) Franklinian (pre-Mississippian), (2) Ellesmerian (Early Mississippian to Early Jurassic), (3) Beaufortian (Early Jurassic to late Early Cretaceous), and (4) Brookian (Late Jurassic or Early Cretaceous to Recent). The composite stratigraphic column in Figure S.5 displays the key source rocks, reservoir intervals, and known hydrocarbon accumulations for the North Slope and the adjacent areas of the Beaufort and Chukchi seas.[2]

The Franklinian succession is considered economic basement (does not contain economic resources) over much of the region but has good to excellent reservoir potential in several areas in the Late Proterozoic and Early Paleozoic carbonate units. There is no known source rock potential in the Franklinian sequence.

The Ellesmerian sequence is comprised of texturally and compositionally mature clastics and carbonates. The nonmarine and shallow marine sandstones and conglomerates of the Mississippian and Triassic were derived from a stable cratonic area that existed to the north of the present Beaufort Sea coastline. The most prolific oil field is found in the Triassic Ivishak Sandstone of the Prudhoe Bay field. The Kekiktuk Conglomerate and Lisburne Group are other important Ellesmerian reservoirs. This sequence also contains important oil and gas source rocks. The Triassic Shublik Formation (and its distal equivalent the Otuk Formation) is one of the major oil-prone source rocks of the North Slope, the Lisburne (and its distal equivalent the Kuna Formation) and the Endicott Groups possess the potential to be locally significant oil and/or gas sources.

[2] See the "Regional Geology of the North Slope" at the following web site for additional information. http://www.dog.dnr.state.ak.us/oil/products/maps/northslope/nsrs/NS_RegionalGeology_80x36_052206cjb.pdf.

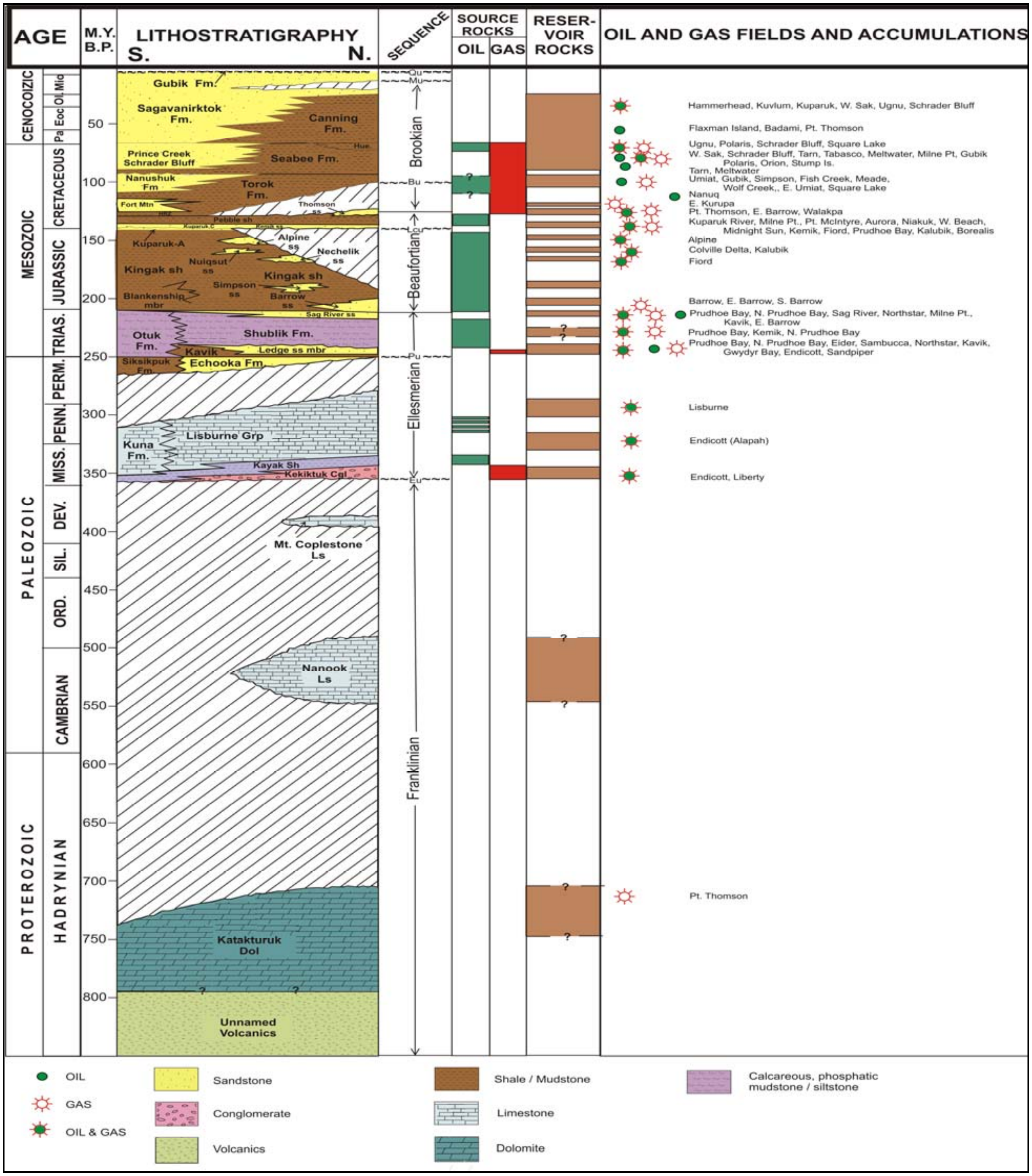

Figure S.5. Generalized North Slope Stratigraphic Column with Source Rocks, Reservoir Horizons, and Oil and Gas Fields/Accumulations Located by Formation. (Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980).

The Beaufortian sequence was derived from the uplifted rift margin associated with the opening of the Canada Basin and the provenance was a combination of Franklinian and recycled Ellesmerian terranes. Consequently the shallow marine Jurassic sandstones of the Kingak Shale and the Early Cretaceous Kuparuk/Kemik/Thomson are compositionally and texturally mature. The Kuparuk River formation is the second most important reservoir interval on the North Slope and the Jurassic sandstones, such as the Alpine and Nechelik, are emerging as important reservoirs in eastern NPRA and the western portion of the Colville-Canning area. Major source rocks include the Kingak Shale (and its distal equivalent the Blankenship Shale) and the Pebble Shale unit.

The Brookian sequence is a product of the Brooks Range orogeny, which resulted from plate convergence along what is now the general trace of the Brooks Range. The Brookian sedimentary rocks are texturally and compositionally immature and represent the entire depositional spectrum from alluvial fans to submarine fans and deep basin systems. These rocks were shed north and east from emerging highlands to the south and southwest into a rapidly subsiding basin, the Colville trough. The Colville trough was progressively filled by northeastward advancing depositional systems that persisted from the Early Cretaceous through the Tertiary. The sandstone and conglomerates of the Brookian sequence tend to possess relatively poor reservoir quality but do serve as reservoirs for large oil accumulations at Ugnu and West Sak. Principal reservoirs include the Nanushuk, Tuluvak, Schrader Bluff, Prince Creek, Sagavanirktok, and Canning formations. Brookian source rocks include the HRZ, Torok Formation, Hue Shale, and Mikkelsen Tongue of the Canning Formation.

S.4.2 Petroleum Geology

The petroleum geology of the North Slope is addressed in terms of source rocks, reservoirs, and traps as related to the regionally recognized sequences, with emphasis on the components of those sequences that are critical to the generation and accumulation of the world-class reserves and potential additional resources of the area. The Ellesmerian, Beaufortian, and Brookian sequences all possess source rocks, reservoir rocks, and economic hydrocarbon accumulations. As depicted in Figure S.5, three of the early discoveries on the North Slope are Ellesmerian accumulations (Prudhoe Bay, Lisburne, and Endicott). The Kuparuk, Point Thomson, and Alpine fields are examples of Beaufortian accumulations. To date the Brookian accumulations have been smaller but include fields such as Tabasco and Tarn, plus the huge but difficult to develop heavy oil accumulations of the West Sak, Schrader Bluff, and Ugnu fields.

The North Slope and adjacent OCS areas of the Beaufort and Chukchi Seas are characterized by a wide array of traps, but the significance and dominance of a specific trap type tends to vary from north to south and to a lesser extent from west to east.

The oil and gas fields located along the Barrow arch are largely structural-stratigraphic accumulations. Bird (1994) summarized the trapping styles present in known accumulations and recognized eleven structural traps, seven (?) stratigraphic traps,[3] and ten combination traps. The structural fields recognized by Bird occur in reservoirs that range in age from Late Triassic to Late Cretaceous and include South Barrow, Kavik, Schrader Bluff and Kuparuk accumulations at Milne Point, Gwydyr Bay, North Prudhoe, Kemik, East Barrow, Northstar, Sandpiper, and Sikulik.

[3] ? – symbol used to signify uncertainty in interpretation.

The stratigraphic traps occur in Jurassic to Tertiary age units and include fields such as South Barrow, West Sak (?), Ugnu (?), Flaxman Island (?), Walakpa, and Simpson, plus Badami. Exploration in the last decade has resulted in the discovery of additional stratigraphic traps in the Colville delta area, including Alpine and most of its Late Jurassic satellite fields. Also, within the western portion of the Colville-Canning area, the Tabasco, Tarn, and Meltwater fields are stratigraphic traps.

The most volumetrically important trap is the combination trap. The recognized combination traps span the Mississippian through late Early Cretaceous and include the two largest fields on the North Slope, the Prudhoe Bay Ivishak accumulation and the Kuparuk River field. In addition, the Lisburne, Point Thomson, Endicott, Niakuk, West Beach, Point McIntyre, Liberty, Sag Delta North, Sambuca, and Midnight Sun are all combination traps.

The ANS is an active and prolific hydrocarbon province with multiple source rocks and reservoirs, diverse trapping mechanisms, and an abundance of large under explored or unexplored acreage. The ANS has an abundance of source rocks and reservoir intervals, and distinct episodes and centers of oil and gas generation and accumulation are recognized. Future exploration and development of the ANS, which includes the adjacent OCS areas, will proceed with these facts and assumptions as one set of primary controls with regard to prioritization of exploration areas and the hydrocarbon phase anticipated. The relative quality of the reservoir intervals; quality, quantity, and thermal history of source rocks; the time of formation and the nature of traps; and timing of trap charge will be driving forces in the quest for reserve additions.

S.4.3 Exploration and Development through December 31, 2004.

ANS exploration commenced with the evaluation of the Cape Simpson oil seeps in 1909. This was followed by a brief interlude of governmental and industry investigations of the area's geology and general hydrocarbon potential. The Naval Petroleum Reserve No. 4 (NPR-4) was established in 1923. In 1943, Public Land Order 42 withdrew all lands north of the drainage divide of the Brooks Range from public entry. The federal government, through the U.S. Navy and the USGS, conducted an initial exploration program in NPR-4 from 1944 to 1953. This program involved geological field investigations and geophysical programs in addition to drilling 36 exploration wells and 45 core-tests (Reed, 1958; Bird, 1981; and Schindler, 1988). This initial round of exploration resulted in the discovery of three sub-economic oil fields, the largest being the Umiat oil field (~70 MMBO), and five small to modest size noncommercial gas accumulations, the largest being the Gubic gas field (~ 600 BCF). The vast majority of the wells were drilled to evaluate the potential of the Cretaceous intervals.

After the naval program was terminated and Public Land Order No. 42 was rescinded, the federal Government initiated a leasing program restricted to those areas external to NPR-4. Between 1958 and 1966, five federal sales were held. The state of Alaska held its first North Slope lease sale in 1964, with two more in 1966 and 1967 (Jamison and others, 1980). Industry began conducting geological field programs in 1958 and acquiring seismic data in 1962. Exploration drilling commenced in 1963. Eleven dry holes were drilled before the Prudhoe Bay discovery in early 1968.

The Prudhoe Bay discovery marked a major turning point in North Slope exploration. Prior to the announcement of the discovery, exploration activity had virtually come to a halt. Thirty-three exploration wells were drilled in 1968 and 1969, resulting in eleven additional discoveries. Ten of the 12 discoveries are still producing oil, with cumulative production of more than 13.5 BBO as of December 31, 2004 and an estimated ultimate recovery of 16.6 BBO.

During the approximately 20-year interval from 1958 through 1979, the only areas available to industry for exploration and development were the state and federal leases onshore between the Colville and Canning rivers, plus some federal leases west of NPRA and the adjacent shallow state-owned waters of the Beaufort Sea. The OCS areas of the Beaufort and Chukchi Seas, NPRA and the area now known as the 1002 Area of ANWR were unavailable. This situation began to change in 1979 when the state and federal governments held a joint lease sale in the Beaufort Sea. Ultimately, the Chukchi Sea OCS; portions of NPRA and the area west of NPRA; and Arctic Slope Regional Corporation (ASRC) acreage within NPRA and the 1002 Area of ANWR would be leased.

Post-Prudhoe Bay, leasing and associated drilling and discovery activity expanded. The federal government sponsored a second exploration program in NPRA (1974 to 1982) during which 28 wells were drilled and two sub-economic gas fields were found (Weimer, 1987 and Schindler, 1988). While no oil accumulations were discovered, good oil shows were noted as far south as the Lisburne well, at approximately 68.5° north and 155.75° west. Most of the exploration activity targeted Prudhoe Bay area reservoirs and plays. Following this second round of exploration in NPRA, the federal government instituted a leasing program and three of four planned lease sales were held during 1982 and 1983. Only one well was eventually drilled on a lease acquired during this short episode of industry activity. It was a dry hole. A second well was drilled within NPRA on ASRC inholdings. It too was unsuccessful and NPRA activity ceased until the late 1990s.

Leasing of state lands was not permitted during the bulk of the 1970s due to issues involving the uncertainty of land status. State leasing resumed in 1979, and between 1979 and 1989 a total of 18 lease sales were held, six offshore and 12 onshore. During this same time interval the MMS held five OCS lease sales, four in the Beaufort Sea, commencing in 1979, and one in the Chukchi Sea, in 1988.

Between 1970 and 1989, 216 exploration wells (an average of 10.8/year) were drilled with the vast majority (185 wells) on state acreage. This episode of exploration drilling resulted in 17 discoveries on state lands, with 10 onshore and seven offshore. Nine of these fields have been developed, with cumulative production through December 31, 2004 of 991 MMBO, and an estimated ultimate recovery of 1.53 BBO. The Beaufort Sea OCS exploration during the late 1970s and 1980s resulted in five discoveries, four of which the MMS and DOG have deemed "significant" discoveries. One well drilled in the Chukchi OCS prior to 1990 did not produce a discovery.

A two-year seismic program in 1984 and1985 evaluated the greater 1002 Area of ANWR for potential leasing and exploration. A single well was drilled on ASRC subsurface mineral holdings within the 1002 Area of ANWR during the 1985 and 1986 drilling season. Test results and all information regarding the stratigraphy, presence or character of shows, and test results have been kept confidential by the operators.

The last fifteen years (1990 to 2004) has been typified by increased diversity in land availability, exploitation of new play types, focus on satellite field development, and new exploration companies/philosophies. Leasing reached new levels, with 37 lease sales, and the size of the average sale was greatly increased by the introduction of area-wide sales. The state of Alaska held 29 lease sales, the MMS conducted five sales (four in the Beaufort OCS and one in the Chukchi OCS), and the BLM held three sales in NPRA. These sales reflect the increased variety of plays and the potential emergence of natural gas as an economic commodity. Much of the leased acreage was in the foothills, a gas-prone area, and large tracts were also leased in NPRA, following a new trend typified by the Alpine oil field.

Exploration drilling remained at relatively high levels from 1990 to 2004, with 131 exploration wells, an average of 8.7 per year. Much of this drilling was focused in and near existing production resulting in the identification and development of small satellite fields. Additional drilling focused on the eastern portions of NPRA, as companies pursued the Beaufortian Kingak sandstones, which provide the reservoir at Alpine and other discoveries, lying to the west of the Kuparuk field. Eastern NPRA drilling activity also targeted Brookian turbidite plays, such as Tarn.

Ninety-eight wells were drilled on state acreage between 1990 and 2004, resulting in 17 discoveries, seven of which have been developed. These fields have a cumulative production of 210 MMBO as of December 31, 2004. The estimated ultimate recovery from these seven fields is 760 MMBO. Eleven exploration wells were drilled in the Beaufort OCS between 1990 and 2004. Two of these wells (Kuvlum No. 1 and Liberty No. 1) discovered hydrocarbons and one (Liberty) will probably be developed within the next three to five years. The Chukchi OCS area had four exploration wells between 1990 and 2004 and three of the wells had good to excellent oil and gas shows with one well, the Burger No. 1, being a gas and condensate discovery. Recent MMS evaluations place the mean gas resources for the Burger discovery for the most likely case at 14.0 TCF and condensate at 724 MMB (Craig and Sherwood, 2005). Eighteen exploration wells have been drilled in NPRA since 2000. Currently, at least three discoveries await development as Alpine satellites (Alpine West, Lookout, and Spark).

The numbers of wells drilled by decade are shown in Figure S.6 and currently held leases by decade of acquisition are shown on Figure S.7. These two figures depict the intensity and direction of exploration activity by decade. The most recent leases also illustrate the areas of current industry interest recognizing that the 1002 Area of ANWR is not available for leasing except for ASRC lands.

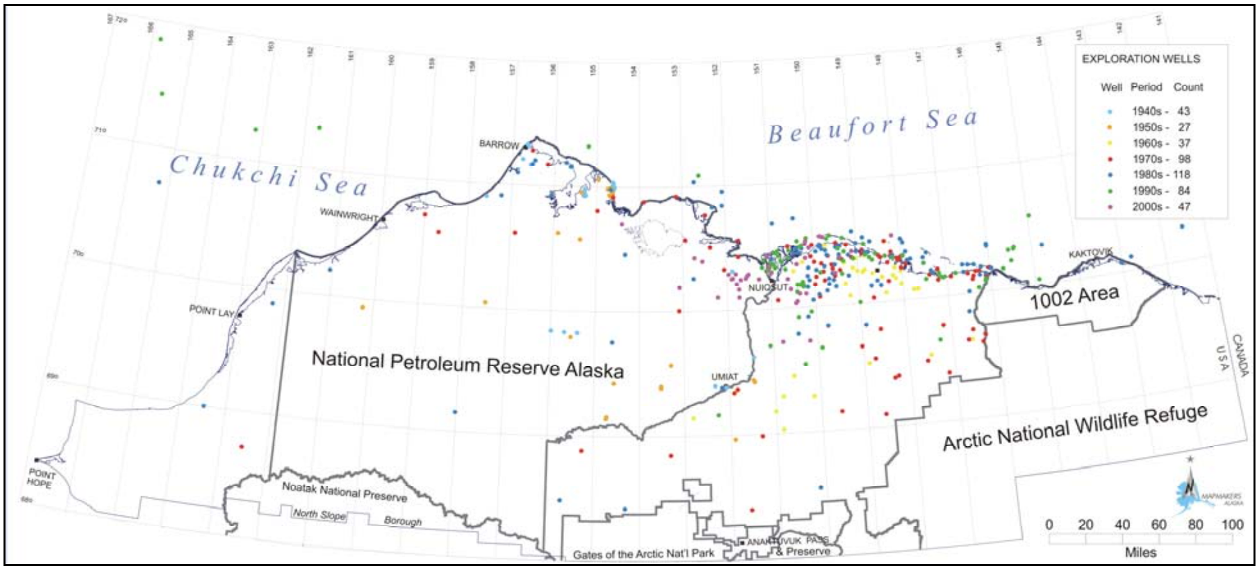

Figure S.6. Exploration wells of the ANS by decade drilled.

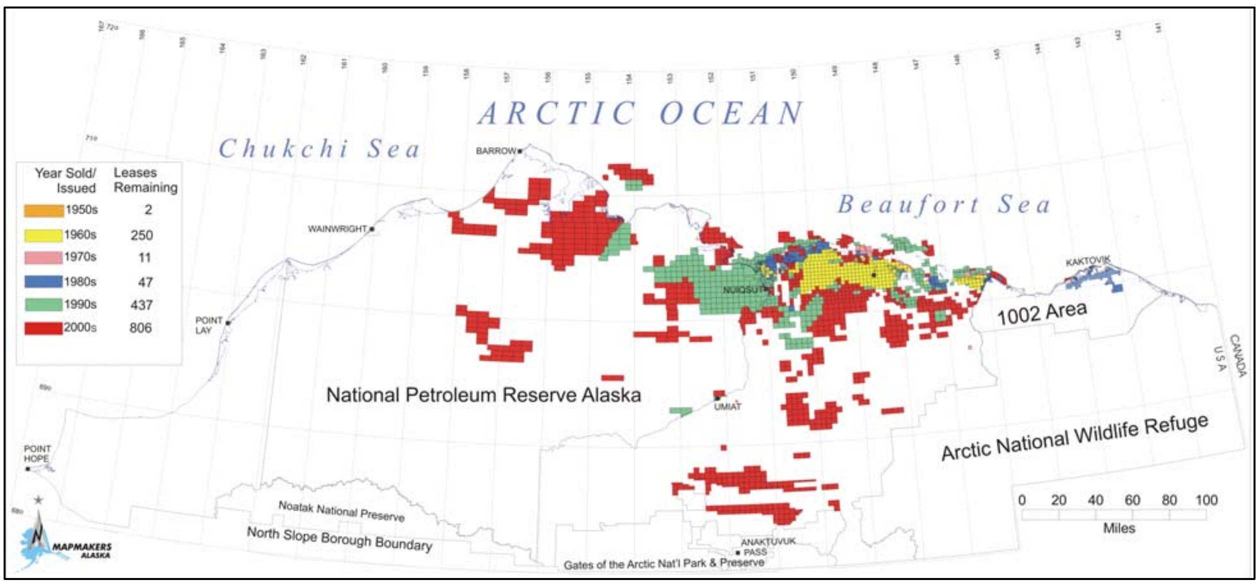

Figure S.7. Number of currently active leases on the ANS by decade leased.

Through December 31, 2004, ANS oil fields have produced 14.989 BBO, or about 70% of the EUR. Gas sales have been limited to sales for local use and field operations (AOGCC, 2004). The estimates for economic remaining reserves are 6.95 to 7.53 BBO and 29.181 TCF. The estimated economic ultimate recovery from the developed fields is 21.94 to 22.52 BBO and 29.225 TCF (Table S.1). The discovered but undeveloped oil and gas fields are estimated to have technically recoverable resources of at least 2.3 BBO and 20.0 TCF (Table S.2).

Table S.1. North Slope oil and gas fields–producing as of December 31, 2004 or soon to start production. (Sources–Thomas, et al., 1991 & 1993; Bird, 1994; ADOG, 2003; ADOG, 2004a).

Field Name	Disc. Date	Reservoirs	Prod. Start Up Date	Cum. Prod. (12/31/2004)	EUR[4]	OOIP or OGIP[5]
South Barrow	1949	Barrow Sandstone	1950	23.0 BCF	26.0 BCF	~37.0[5] BCF
Prudhoe Bay	1968	Ivishak, Shublik, Sag River Fms.	1969 (tests)	-----	26,687 BCF	41,000 BCF
			1977	11,144 MMBO	13,841MMBO	25,000[6]MMBO
Lisburne	1968	Lisburne	1983 (tests)	-----	347 BCF	~900.0 BCF
			1985	154 MMB0	192 MMBO	3,000 MMBO
Orion	1968	Schrader Bluff Fm.	2004	2.3 MMBO	214–446 MMBO	1,200 MMBO
Ugnu	1969	Sagavanirktok, Prince Creek Ss.		0.016MMBO	350–700? MMBO	7,000[7] MMBO
Kuparuk River	1969	Kuparuk Formation A and C Ss.	????	-----	987 BCF	~1,400 BCF
			1981	1,975 MMBO	2,833 MMBO	5,690 MMBO
West Sak	1969	Sagavanirktok, Prince Creek Fms.	1998	15.6 MMBO	530 MMBO	8,000[8] MMBO
Milne Point	1969	Kuparuk Fm.	1985	180 MMBO	418 MMBO	525 MMBO
		Schrader Bluff Fm.	1991	38.1 MMBO	460 MMBO	4,000 MMBO
		Sag River & Ivishak Fms.	1995	1.6 MMBO	1.6 MMBO	62 MMBO
Borealis	1969	Kuparuk Fm.	2001	30.8 MMBO	121 MMBO	195–277 MMBO
Aurora	1969	Kuparuk Fm.	2000	11.4 MMBO	39 MMBO	110–146 MMBO
Polaris	1969	Schrader Bluff Fm.	1999	3.5 MMBO	66 MMBO	350–750? MMBO
North Prudhoe Bay	1970	Ivishak Fm.	1993	2.1 MMBO	2.1 MMBO	12 MMBO
East Barrow	1974	Barrow Ss.	1981	10 BCF	19.2 BCF	~27.0 BCF
West Beach	1976	Kuparuk C Ss.	1993	3.6 MMBO	3.6 MMBO	15–25 MMBO
Endicott	1978	Kekiktuk Conglomerate	????	-----	979 BCF	~1,400 BCF
			1986	448 MMB0	571 MMBO	1,059 MMBO
Walakpa.	1980	Walakpa Ss	1992	11 BCF	180 BCF	~250 BCF
Sag Delta North	1982	Alapah Limestone	1989	7.3 MMBO	7.3 MMBO	3.7 MMBO
Northstar	1984	Ivishak Fm.	2001	67 MMBO	196 MMBO	325 MMBO
Niakuk	1985	Kuparuk C Ss.	1994	81 MMBO	113 MMBO	200 MMBO
Colville Delta	1985	Nuiqsut Ss.	-----	-----	25 MMBO	-----

[4] ADOG (2004) is the source for most of EUR values.
[5] OGIP volumes labeled with a ~ are back-calculated from EUR values using an average recovery of 70%.
[6] OOIP for Prudhoe Bay oil (BP Exploration and ARCO Alaska, 2001).
[7] OOIP values shown for Ugnu reflect only the "sweet spots" where production is centered and not the total OOIP for the entire accumulations. OOIP for the entire Ugnu accumulation is ~ 15-24 BBO (McGuire and others, 2005 and Smith and others, 2005).
[8] OOIP for entire West Sak accumulation ~ 11-21 BBO (McGuire and others, 2005 and Bross, 2004)

Field Name	Disc. Date	Reservoirs	Prod. Start Up Date	Cum. Prod. (12/31/2004)	EUR[4]	OOIP or OGIP[5]
Tabasco	1986	Tabasco Ss. Schrader Bluff Fm.	1998	9.7 MMBO	23.3 MMBO	48–131 MMBO
Point McIntyre	1988	Kuparuk C Ss.	1993	384 MMBO	591 MMBO	950 MMBO
Badami	1990	Badami Ss. Canning Fm.	1998	4.3 MMB0	60.0? MMBO	300? MMBO
Tarn	1991	Seabee Fm.	1998	65 MMBO	127 MMBO	255 MMBO
Kalubik	1992	Kuparuk & Nuiqsut Ss.		-----	OIL(?) MMBO)	-----
Fiord	1992	Kuparuk A & Nechelik Ss.		-----	50 MMBO	150 MMBO
Cascade	1993	Kuparuk Fm.	1996	-----	50 MMBO	-----
Alpine	1994	Alpine Ss.	2000	138 MMBO	555 MMBO	900–1,100 MMBO
Midnight Sun	1997	Kuparuk C Ss.	1998	11.3 MMBO	23 MMBO	40–60 MMBO
Eider	1998	Ivishak Fm.	1999	2.7 MMBO	6.0 MMBO	13.2 MMBO
Meltwater	2000	Bermuda Ss. Seabee Fm.	2001	7.7 MMBO	44 MMBO	132 MMBO
Nanuq	2000	Nanuq Ss. Torok Fm.	2001	-----	40 MMBO	150 MMBO
Spark	2000	Alpine Ss.		-----	50 MMBO	150 MMBO
Palm	2001	Kuparuk River Fm.	2003	????	35 MMBO	70 MMBO
Alpine West	2001	Alpine Ss.		-----	50 MMBO	150MMBO
Lookout	2002	Alpine Ss.		-----	50.0 MMBO	150 MMBO
TOTALS	**N.A.**	**N.A.**	**N.A.**	**14,989 MMBO/ 44.00 BCF**	**21,940-22,520 MMBO/ 29,225 BCF**	**60,200-61,040 MMBO[9]/ 45,000 BCF**

Table S.2. **North Slope, Alaska–Undeveloped oil and gas accumulations as of January 1, 2005 (after Bird, 1991 and Thomas, and others, 1991 and 1993)**

Accumulation or Field	Reservoir Formation(s)	Year of Discovery	Estimated Technically Recoverable Resources
Umiat[10]	Nanushuk Fm.	1946	70 MMBO, 50 BCF
Fish Creek[10]	Nanushuk Fm.	1949	OIL (? MMBO)
Simpson[10]	Nanushuk Fm.	1950	12 MMBO
Meade[10]	Nanushuk Fm.	1950	20 BCF
Wolf Creek[10]	Nanushuk Fm.	1951	GAS (? BCF)
Gubik[10]	Tuluvak & Nanushuk Fms.	1951	600 BCF
Square Lake[10]	Nanushuk Fm.	1952	58 BCF
E. Umiat	Nanushuk Fm.	1964	4 BCF
Kavik	Ivishak Fm.	1969	115 BCF
Gwydyr Bay[11]	Ivishak Fm.	1969	30–60 MMBO
Kemik	Shublik Fm.	1972	100 + BCF

[9] 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 1 and 2 the OOIP range is 67.0 to 88.0 BBO

[10] Navy and other federally-operated wells.

[11] Pioneer Natural Resources has applied to develop several small accumulations in this area, probably by 2006.

Accumulation or Field	Reservoir Formation(s)	Year of Discovery	Estimated Technically Recoverable Resources
Flaxman Island	Canning Fm.	1975	OIL (? MMBO)
East Kurupa	Torok-Fortress Mtn. Fm.	1976	GAS (? BCF)
Point Thomson	Thomson Ss. & Canning Fm.	1977	300 MMBO, 5000 BCF
Mikkelson	Canning Fm.	1978	OIL (? MMBO)
Tern Is. (Liberty)	Kekiktuk Conglomerate	1982	150 MMBO
Hemi Springs	Kuparuk Fm.	1984	OIL (?MMBO)
Hammerhead	Sagavanirktok Fm.	1985	~200 MMBO
Sandpiper	Ivishak Fm.	1986	150 MMBO/GAS (? BCF)
Sikulik	Barrow Ss.	1988	16 BCF
Stinson[12]	????	1990	OIL (? MMBO)
Burger	Kuparuk Equivalent	1990	14,000 BCF, 724 MMBO
Kuvlum[12]	????	1993	400 MMBO
Thetis Island[12]	Nuiqsuit	1993	OIL (? MMBO)
Sourdough[12]	?????	1994	~100 MMBO
Pete's Wicked[12,,13]	Sagavanirktok & Ivishak Fms.	1997	OIL (? MMBO)
Sambucca[12]	Ivishak Fm.	1997	19 MMBO(?)
Oooguruk[12]	Nuiqsut Ss.(?)	2003	70 MMBO(?)
Nikaitchuq[12]	Nuiqsut and Sag River Ss.(?)	2004	70 MMBO(?)
Tuvaaq	Schrader Bluff Fm.	2005	OIL (?MMB0)
Total			**2,300$^+$ MMBO/ 20,000$^+$ BCF**

The exploration success of the Colville-Canning area spurred 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 2004, 72 lease sales have occurred, covering more than 26.5 million acres have been leased. Some acreage has been leased more than once.

As of January 1, 2005, there were 1,553 active leases in the Beaufort Sea, NPRA, and the Colville-Canning areas with the majority, (80%) issued in the last 15 years. These newer leases are concentrated in NPRA and in the Brooks Range foothills (Figure S.7). The 2000 to 2004 leasing activity and the number of exploration wells by year from 2000 to 2004 and proposed for 2005 are shown on Figure S.8. Recent leasing trends emphasize: (1) activity by independents and smaller companies in the Colville Delta-Gwydyr Bay area of the northern Colville-Canning area and adjacent state waters and eastern NPRA, (2) expectations for a gas pipeline and market with the interest in the Central Arctic southern foothills acreage; (3) westward extension of exploration into NPRA based on the discovery and development at Alpine; and (4) continued emphasis by the major producers on close-in satellite development.

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

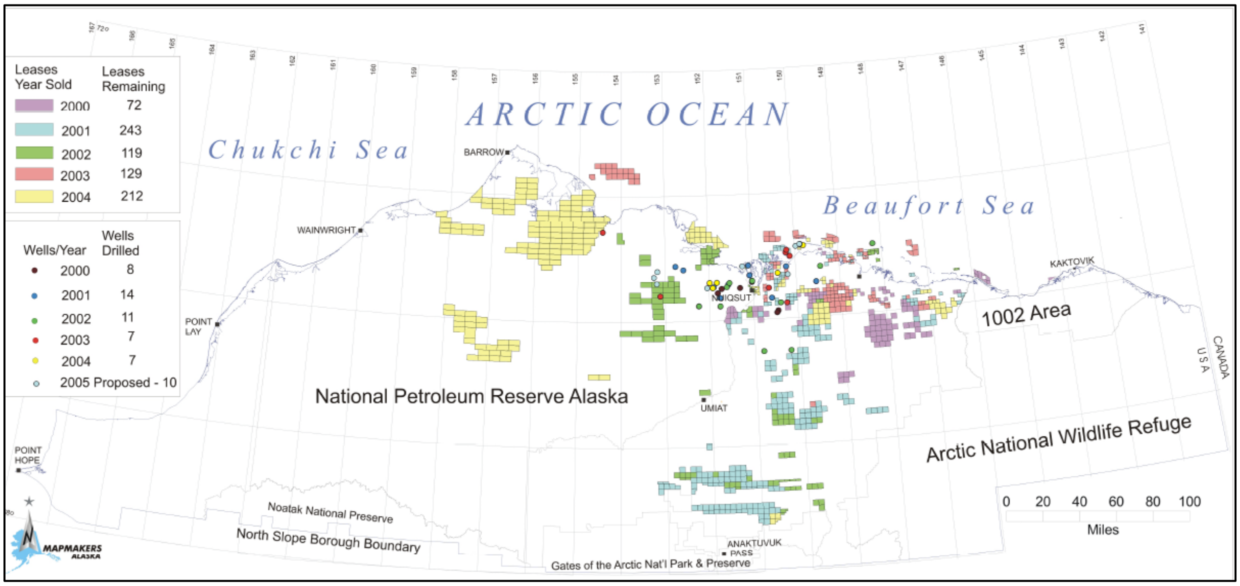

Figure S.8. ANS Leases and Exploration Wells–2000 to 2004.

Nearly 230,000 line-miles of 2D seismic data had been acquired by the end of 2004 consisting of approximately 61,000 miles of land-based and on-ice data and more than 168,000 miles of marine data. Land-based 3D seismic data covers more than 10,700 square miles. The extant of OCS 3D data acquisition is not available, but at least 18 programs have been completed, with 11 on ice and 7 marine acquisitions.

Exploration drilling has been widespread but not intensive. On the North Slope and in the adjacent Beaufort and Chukchi Seas, a total of 454 wells have been classified as exploration wells (Figure S.6). 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 explored areas with approximately 301 exploration wells. The total for state and Native lands is approximately 23,000 square miles (Bird and others, 2005) and yields a well density of one well per 76 square miles. Within NPRA, 118 exploration wells have been drilled. If the 45 core tests are discounted, the federal exploration efforts and industry exploration drilling has totaled 73 exploration wells. For an area of approximately 36,000 square miles, this yields a drilling density of one well per 495 square miles. For the Beaufort Sea OCS shelf, with an area of approximately 19,000 square miles, the 30 exploration wells results in a well density of one well per 630 square miles. The prospective portion of 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 a drilling density of approximately one exploration well per 22 square miles. Only forty-five of the 301 exploration wells have been located south of 70º north latitude (Figure S.6). This area, which constitutes nearly 75% of the state acreage, has a well density of one well per 383 square miles.

Figure S.8 shows both the recent exploration wells and their distribution and also the permitted wells for the 2005 drilling season. This planned activity foreshadows the near-term exploration trends and continues the pattern of activity represented by the last four to five years of exploration drilling. The areas of concentration continue to be in or near currently established production and infrastructure and westward into NPRA. The latter activity continues the evaluation of the productive trend at Alpine and its satellites and the search for Brookian turbidite and additional Kuparuk production.

Large volumes of gas have been discovered in conjunction with past and present oil exploration efforts, and vast areas of high gas potential remain under explored or unexplored. Based on currently published gas estimates 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.

While these volumes (EUR of about 24 BBO and known gas resources of about 50 TCF) are impressive, they are dwarfed when compared to the volumes estimated to have been generated by the area's prolific source rocks. The Ellesmerian Petroleum system is estimated to have generated 8 trillion barrels of oil (Bird, 1994). A 10% trapping efficiency would provide 800 BBO in place. The other petroleum systems do not appear to have possessed the generation potential of the Ellesmerian system, but as a group would probably have at least one-third the generative potential. The potential upside of the area is much greater than the reserves discovered to date.

S.4.4 Future Exploration Potential

Future projections were viewed from two time periods, near term (2005 to 2015) and long term (2015 to 2050). The near term is oil-centered, while the long term is marked by the emergence of gas as a major, if not dominant factor in exploration and development activities. The forecast incorporates a number of basic assumptions and relied on the resource assessments conducted by the USGS for onshore portions of the ANS and the MMS for the OCS.

The USGS and MMS assessments for mean technically recoverable oil for ANS exploration provinces are shown in Table S.1 for oil and Table S.2 for gas (Bird and Houseknecht, 1998; MMS, 2000; Bird and Houseknecht, 2002; Bird and others, 2005).[14] The gas volumes are the totals for gas associated with oil fields (gas caps and solution gas) and gas not associated with oil fields. These tables also include the province areas and the respective barrels of oil or millions of cubic feet (MMCF) of gas per acre and per square mile. The relative ranking of these volumes per unit area emphasize the potential impact of the 1002 Area of ANWR on future exploration activity. If the 1002 Area of ANWR is opened, a huge increase in oil reserves could be achieved from a small area relative to other regions. This translates to less expense for infrastructure and less overall environmental impact for the same yield in oil reserves.

[14] Sherwood, K.W., MMS, Personal communication, 2005.

Table S.3 . Mean technically recoverable oil as estimated by USGS/MMS per acre and square mile of prospective area for the ANS exploration provinces.

Exploration Province	Mean Tech. Rec. Oil (BBO)	Province Area (Million Acres)[a]	Barrels oil/Acre	Barrels Oil/Sq. Mile
ANWR 1002 Area[b]	10.4	1.9	5,475	3,504,000
Beaufort Sea OCS	6.9	12.2	565	361,600
NPRA	10.6	24.2	440	281,600
Colville-Canning Area and Adjacent State waters	4.5	14.7	306	195,840
Chukchi Sea OCS	15.5	41.3	306	195,840

a. Areas for the Beaufort and Chukchi Sea evaluations are those used in the 2000 MMS evaluations and are significantly different from those utilized in earlier assessments because of a 1996 re-allocation of the western one-third of the Beaufort Sea Planning area.
b. These estimates include the Entire Area (federal and Native lands and state of Alaska offshore areas).

Table S.4. Mean technically recoverable gas as estimated by USGS/MMS per acre and square mile of prospective area as evaluated for the ANS exploration provinces.

Exploration Province	Mean Tech. Rec. Gas (TCF)	Province Area (Million Acres)[a]	MMCF Gas/Acre	MMCF Gas/Sq. Mile
ANWR 1002 Area[b]	3.84	1.9	2.021	1,293.44
Beaufort Sea OCS	32.1	12.2	2.631	1,683.94
NPRA	61.4	24.2	2.537	1,623.80
Colville-Canning Area and Adjacent State waters	37.5	14.7	2.551	1,632.65
Chukchi Sea OCS	60.1	41.3	1.455	0.931

a. Areas for the Beaufort and Chukchi Sea evaluations are those used in the 2000 MMS evaluations and are significantly different from those utilized in earlier assessments because of a 1996 re-allocation of the western one-third of the Beaufort Sea Planning area.
b. These estimates include the Entire Area (federal and Native lands and state of Alaska offshore areas).

OOIP and OGIP volumes were derived either directly from USGS and MMS assessments or by back-calculating the in-place volumes using the published recoverable volumes (by play) and the play recovery factor. For the entire study area the sum of the calculated oil-in-place volumes is 196 BBO and the in-place gas volume is 320 TCF.

To develop the forecast for both the near and long term, several additional assumptions were made based on sound exploration and development practices and the assessment area's recoverable resource estimates, on a play-by-play basis. It was assumed that: (1) the exploration process would identify and discover the larger, more proximal fields and then move sequentially away from existing infrastructure; (2) exploration would be time-sensitive with respect to which areas would be explored first, considering both accessibility and the oil versus gas issue; (3) depending on the existing knowledge base, the percentage of economic reserves versus technically recoverable resources would range from 50 to 70%;[15] and (4) maximum field size and size frequency would generally conform to those proposed by the USGS and MMS assessment teams.

The **short-term** (2005 to 2015) exploration efforts are forecast to result in the discovery and development of approximately 2.85 BBO and 12.0 TCF. The oil is expected to be distributed as follows: 1.1 BBO in the Colville-Canning area/state waters, 0.65 BBO in the Beaufort OCS, and 1.1 BBO in NPRA. The gas will be discovered and remain in varying stages of development awaiting opening of the gas pipeline, with 10.0 TCF from the Colville-Canning area, 1.0 TCF from the Beaufort OCS and 1.0 TCF from NPRA. The Beaufort and NPRA discoveries are assumed to be associated gas (Table S.3).

The **long-term** (2015 to 2050) exploration and development efforts involve activities in all five of the sub-provinces and are expected to total 28.0 BBO and 125.3 TCF. The oil reserve additions are widely distributed: 2.05 BBO from Colville-Canning area/state waters, 4.3 BBO from Beaufort OCS, 5.4 BBO from NPRA, 6.75 BBO from 1002 area of ANWR, and 9.5 BBO from Chukchi OCS. The greatest risk is associated with the Chukchi reserves, simply because of the remoteness of the area and the heavy reliance on successes in other areas for the exploration in the Chukchi Sea to be economic. The gas exploration efforts are similarly widespread with expected gas reserve additions of: 2.0+ TCF in the 1002 Area, 20.0 TCF in Beaufort OCS, 23.3 TCF in Colville-Canning area (chiefly the foothills area), 30.0 TCF in NPRA, and 50.0 TCF in the Chukchi OCS. Burger, in the Chukchi Sea, is already estimated to have risked mean resources of 9.48 TCF (Craig and Sherwood, 2005, Table 1). Thus, despite their magnitude, the values for the Chukchi Sea are quite reasonable, even with the remoteness of the area as an economic consideration.

For the complete study interval, 2005 to 2050, forecasted reserve additions total 30.85 BBO and 137.3 TCF. When compared to the estimated OOIP of 196 BBO (adjusted to 125 BBO to account for the approximately 70 BBO of discovered in-place oil) and the OGIP of 320 TCF (adjusted to 275 TCF to account for discovered gas), this is a recovery rate of 25% for oil and 50% for gas. These estimates are summarized by exploration province in Table S.5 and are also shown in Figure S.9.

Table S.5 . Summary of economically recoverable oil and gas additions for ANS exploration provinces.[15]

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	1.0 TCF (assoc. gas)	4.3 BBO	20.0 TCF	4.95 BBO	21.0 TCF

[15] In the Engineering and Economic Assessment section of the report, the estimated economic reserves are determined from discounted cash flow analyses for a range of oil and gas prices using production forecasts developed in this study for each field. In this section published volumes or volumes based on a percentage of technically recoverable resources are used to estimate economically recoverable volumes.

EXPLORATION PROVINCE	Near Term 2005 to 2015		Long Term 2015 to 2050		Total 2005 to 2050	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
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.	6.25 BBO	2.0+ TCF	6.25 BBO	2.0+ TCF
TOTAL ARCTIC ALASKA	**2.85 BBO**	**12.0 TCF**	**27.50 BB0**	**125.3 TCF**	**30.35 BBO**	**137.3 TCF**

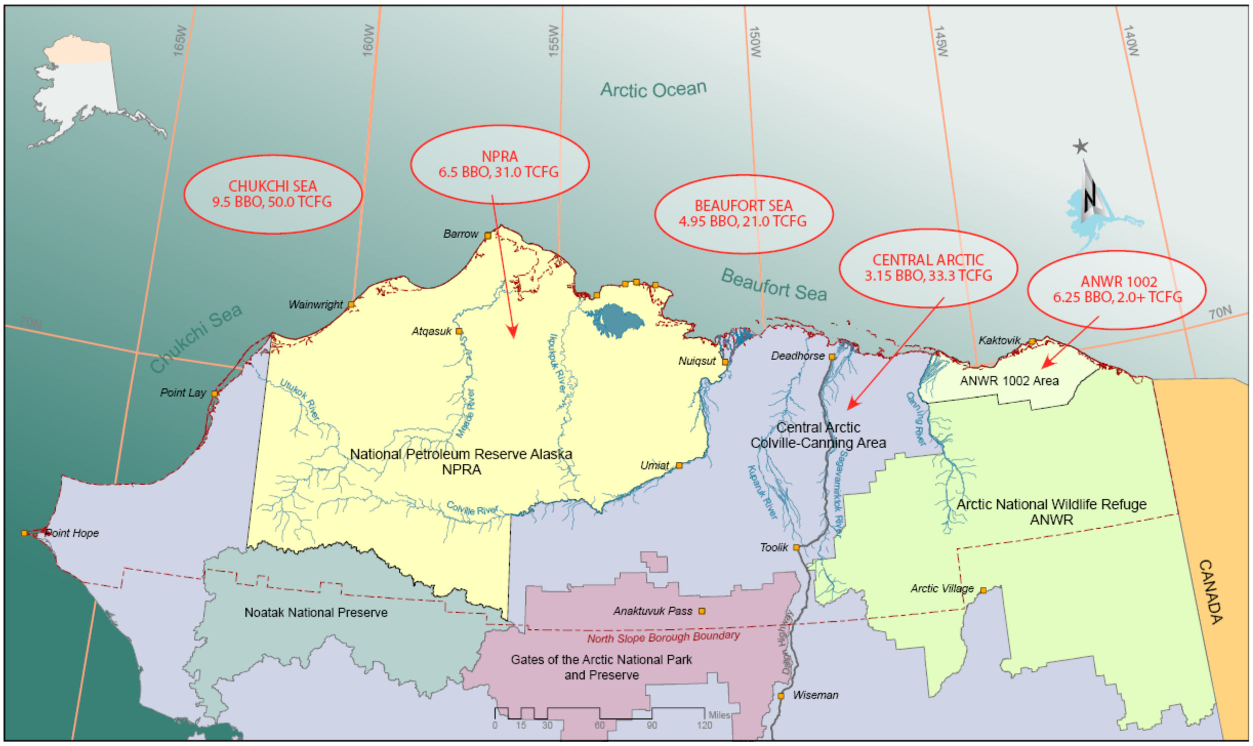

Figure S.9. Estimated additions to Northern Alaska economically recoverable oil and gas resources from exploration during 2005 to 2050 interval. (Current cumulative production, ERR, and reserves growth volumes are not included.)

S.4.5 Reserves Growth in Existing Fields

An additional component of the ultimate ANS reserve base is reserves growth in existing fields. The current EUR is approximately 7.2 BBO higher (59%) than the aggregate sum of the initial EUR's for the existing fields (see Section 2.5.2). The increase in recoverable oil through advances in technology and higher prices is expected to continue for the foreseeable future. This is especially true in the case of the high viscosity, heavy oils of the West Sak, Ugnu, and Schrader Bluff accumulations. New technologies, especially the application of enriched hydrocarbon gas and CO_2 water-alternating-gas (WAG) floods, are expected to greatly increase the recovery factors for viscous oil resources. Additional reserves growth from existing fields is estimated at 5.0 to 6.0 BBO, with 60 to 70% coming from the high viscosity oil fields.

S.4.6 Summary of ANS Future Potential

The forecast volumes for additional economically recoverable oil and gas by ANS area and type are listed in Table S.4. For comparison, cumulative oil production through December 31, 2004 was 14.90 BBO, and current economically remaining reserve estimates are 6.95 to 7.35 BBO and 35.0 TCF of gas, all from areas of current activity (northern portion of Colville-Canning province and adjacent Beaufort Sea waters, and eastern NPRA – see Figure S.2).

Table S.6. ANS Forecast 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 Beaufort Sea Waters, and eastern NPRA – see Figure S.2.

Based on the geological considerations discussed in this report, 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) high oil and gas prices continue, (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 controversial. 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.

S.5 Engineering and Economic Evaluation

This section presents an engineering and economic evaluation of the Alaska North Slope (ANS) petroleum producing complex. The goal is to combine the geologic and engineering findings to evaluate future economical oil and gas production for the ANS and estimate the resulting revenue generated for industry, the state of Alaska, and the federal government. Specific objectives of the analyses are to:

- Estimate future ANS economical oil and gas production from: (1) currently developed fields, (2) pools with announced and pending development plans, and (3) pools with recognized potential for development.
- Determine the minimum economic field sizes (MEFS) for exploration and production (E&P) projects at differing distances from the existing petroleum production infrastructure and exploration areas (Central Arctic including Foothills gas, NPRA, 1002 Area of ANWR, and the Beaufort and Chukchi Sea OCS areas).
- Examine the role of natural gas off-take and sales through an Alaska Gas Pipeline, assumed to be operational in 2015, on the future economic viability of ANS oil and gas development and production.
- Identify future facility constraints for oil, water, and gas handling and analyze impact of facility sharing on the economics of future development.

A brief description of each pool and field is provided and production forecasts of estimated remaining technically and economically recoverable oil and gas reserves 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. The economic analysis provides estimated remaining reserves (ERR), and estimated ultimate reserves (EUR) for four oil and gas price scenarios.[16] Production forecasts are developed for each producing pool. These forecasts are used to generate the TUR estimates used in the economic analysis for each pool to determine EUR's. Generic production forecasts are developed for pools that may be discovered through future exploration based on anticipated formation types and analogous producing field characteristics. Forecasts of this type are used to estimate MEFS for various

[16] 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. The U.S. Security and Exchange Commission (SEC) definition of reserves requires a more rigorous analysis to determine the fraction of technically recoverable hydrocarbons that may be produced economically under current economic and operating conditions; i.e., pricing and operating costs as of the date an estimate is made (SEC, 1975). The SEC recognizes only proved developed and proved undeveloped as reserve categories. The Society of Petroleum Engineers (SPE, 2001) further divides reserves into three general categories with increasing uncertainty: proved, probable, and possible, with additional proved sub-categories for proved developed and proved undeveloped. The SPE methodology provides a formal mechanism for reserve recognition and category upgrades based on continued field development and the implementation of improved hydrocarbon recovery technologies.

locations across the ANS basins described in Section 2.

These results are combined into composite forecasts of future ANS oil and gas production using specific investment, operating costs, and pricing assumptions. The implications of future development scenarios on the long-term viability of ANS oil and gas production are identified and summarized.

S.5.1 Future Production Capacity Issues

A major issue facing Alaska, the Nation, and the industry is whether ANS production can be maintained or increased from current levels, or whether ANS production is in the throes of a persistent decline. The answer hinges on the potential for new discoveries, continued development of small and satellite pools, development of the heavy viscous oil resources, increasing recovery from existing reservoirs by applying technology advancements, and the effect of major gas sales on the economic life of ANS oil and gas production.

A limiting factor in the economic life of ANS oil production absent continued new discoveries is the TAPS lower operating limit. The recently completed TAPS Pipeline Reconfiguration by Alyeska Pipeline Service Company (Alyeska, 2004) reduced the number of pumping stations from 10 to four (PS 1, 3, 4, and 9). All four stations must be on-line to sustain any flow rate because of the mountain ranges and associated elevation changes between PS1 and Valdez. The pipeline reconfiguration replaced natural gas pump drivers with electric motors and modern centrifugal pumps. The three driver packages currently installed at PS 1, 3, 4, and 9 support throughput of up to 1.14 MMBOPD. Placing additional pump skids at these pump stations and at PS 7 and 12 would increase capacity to 1.5 MMBOPD (Alyeska, 2004). A return to 10 stations would increase the capacity back to the historical TAPS peak capacity of about 2.0 MMBOPD. Conversely, reducing the number of pumping units to one unit at each of the four required stations would result an operating range from 300,000 to 450,000 BOPD.[17]

The crude oil mix defined by the current and future crude oil characteristics and temperature profiles from known and undiscovered ANS pools will potentially have an impact on this mechanical lower limit, as well as on the rates attainable for each pumping configuration. Because wellhead oil prices are determined by subtracting transportation costs (tanker and TAPS tariffs) from U.S. West Coast oil prices, an increased tariff results in a lower wellhead price of the oil and reduced revenues to the industry and the state and federal governments. The TAPS lower limit, as illustrated in Figure S.4, could be reached by 2025 unless additional reserves are developed. Additional reserves would be secured through several mechanisms: reserves growth in existing fields; application of advanced technology, particularly in the viscous and heavy oil fields; and new economically developable discoveries

The timing and amount of economically recoverable oil from the ANS that would be lost because of the total ANS production rate reaching the TAPS lower limit is described below.

S.5.2 Development History

The discovery of the Prudhoe Bay field in January 1968 is significant not only for the

[17] Personal communication, Alyeska Pipeline Service Company, June 2006.

size of the discovery, but also because it is the largest oil accumulation in North America. The value of this single discovery supported the grass-roots development of a petroleum infrastructure on the ANS. The ANS accounted for 25% of the U.S. domestic oil production in 1988 and still accounts for 17% almost 30 years after production began in 1977 (see Figure S.2 and Figure S.3). Continued application of advanced technology, coupled with continuous cost reduction efforts, has allowed this major oil production province to sustain a major role in U.S. energy supply. Further, continued application of advanced technologies has enabled technical and economic access to an increasing fraction of the total petroleum endowment, while minimizing physical impact.

The development of the Prudhoe Bay Unit (PBU) required the installation of a complete petroleum infrastructure prior to first delivery of oil to domestic markets, which occurred 10 years after discovery (Thomas et al., 1991). The construction of TAPS and the delivery of production facilities, drilling supplies, and crew quarters represented a huge logistical undertaking and opened the way for additional development in Arctic regions. PBU production increased from 316,000 BOPD in 1977 to more than 1,500,000 BOPD by 1980, a rate sustained though 1989 (Figure S.10). Peak production coincided with higher oil prices through 1985, providing large revenues to the stakeholders (industry and state, local, and federal governments). Industry reinvested a portion of these revenues to support the development of the Kuparuk River Unit (KRU) and adjacent fields. KRU development was started in 1981, increased to more than 300,000 BOPD by 1988, and began declining in 1992. KRU development facilitated full utilization of TAPS capacity consistent with the oil markets and the investment climate.

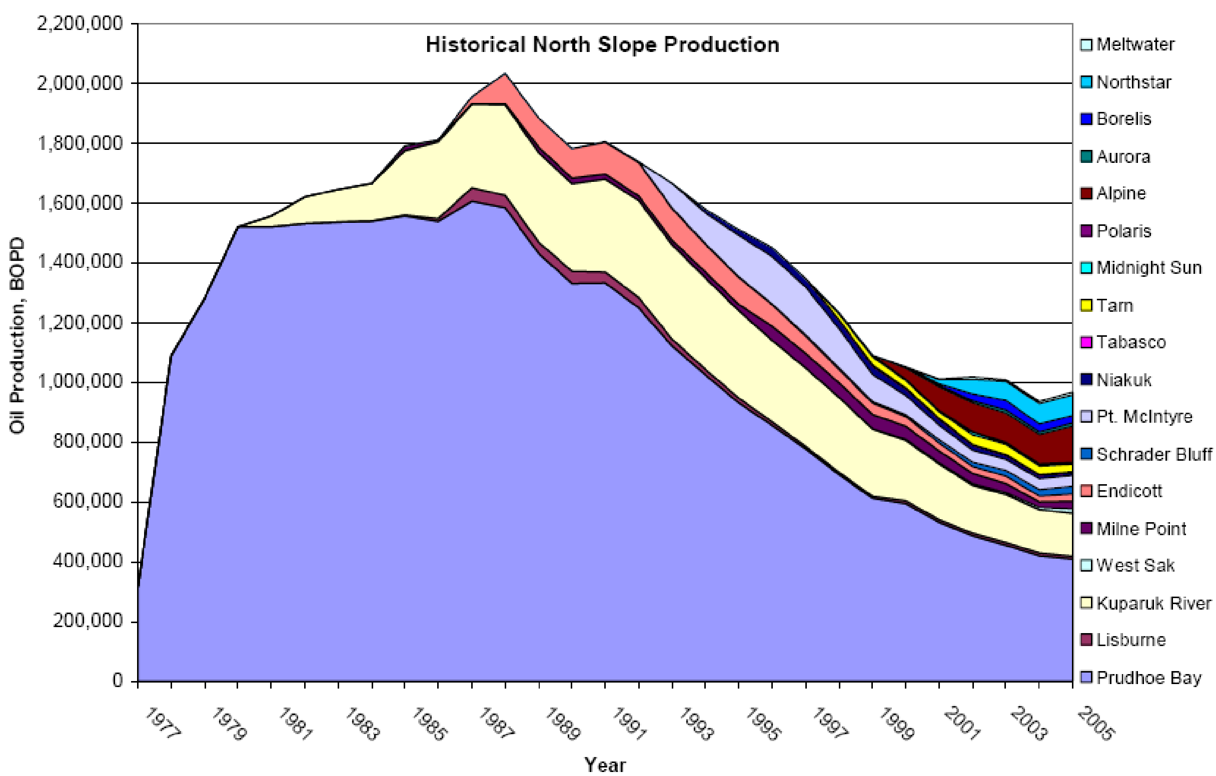

Figure S.10. ANS annual historical oil production. (Data from AOGCC, 2005)

Total ANS oil production peaked at more than 2 MMBOPD in 1988, including production from the Lisburne and Endicott fields. Production steadily declined from 1989 through 2000, stabilized at about 1 MMBOPD between 2000 and 2003, and fell again to about 900,000 BOPD in 2005. In comparison, Lower 48 oil production declined over the entire time period, as shown in Figure S.3.

The discovery of new pools, the development of satellite accumulations, and the application of advanced technology have slowed the ANS production decline in the short term (Figure S.10). To further retard the decline, the inevitable production declines from the major fields such as PBU and KRU must be replaced by production from a large number of smaller fields or from undiscovered giant fields in other ANS areas. This process is graphically illustrated by the increasing number of smaller ‘wedges’ of new pools moderating the overall production decline.

S.5.3 Source Data

The TRR and TUR forecasts rely on publicly available information 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 synthesized for the preparation of production forecasts and development drilling scenarios.

The AOGCC maintains a public database of all production data from all producing pools in Alaska. This database consists of: detailed well information; oil, water, gas production; production days; water injection, gas injection, and water and gas injection days. These data were used to construct derivative production plots (water and gas trends) for analysis.

S.5.4 Reserves Forecasts

The technical remaining recoverable (TRR) oil and gas resources are estimated from technical aspects regarding pool development, operational strategies, and recovery technologies employed without specific consideration of price expectations and development costs. The method relies on 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 instances where historical production data are not available or are not adequate for decline curve analysis, reserves are based on geology, relying on volumetric quantities of petroleum-in-place and expected recovery factors from analogous reservoirs and fields or, if available, from limited production test data. Hypothetical project developments use a standard production build-up period, peak production plateau, and a decline production schedule, with the length and magnitude of the plateau determined by the TRR oil or gas. These forecasts are described for each pool in Section 3 of the report.

Future water and gas production forecasts are needed to estimate variable operating costs and to examine facility constraints. These are estimated for each pool using an empirical dimensionless-variable approach based on water cut (WC) and gas-to-oil ratio (GOR) described in Section 3 of the report. Where sufficient data are not available, such as recently developed pools, data for similar pools are used to develop the forecasts.

The estimates of the economic remaining reserves (ERR) for each pool are based on an after-tax discounted cash flow evaluation relying on the estimates for TRR oil or gas, water and gas forecasts, investments, operating costs, and oil and gas price assumptions.

S.5.5 Economic Evaluation

The rational behind the economic evaluation – the approach, data sources, key assumptions, economic model, and economic parameters – are described in Section 3.2 of the report. Results of the ANS economic evaluation are presented for each pool or field. The TRR and associated production forecasts for oil, gas, and water are used as primary resource inputs to the economic evaluation. The results derived include ERR; gross revenue; investment requirement; operating costs; state, federal, and local government taxes and royalties; net income to the operators, and the last year of economic production.

Two major operational scenarios are considered: (1) oil production from the existing fields and new developments with no major gas sales, and (2) oil production after the start of major gas sales from the ANS. This second scenario is predicated on the construction of the proposed 52-inch Alaska Gas Pipeline (AGP) and transport of 4.5 billion cubic feet per day (BCFPD) of gas from the ANS to markets in Alaska, Canada, and the Lower 48 states. It is assumed the AGP will be operational in the 2015 to 2016 period.

Specific goals of the economic evaluations are to estimate likely economic oil and gas production from: (a) existing fields and satellite developments, (b) from discovered but undeveloped accumulations with pending or announced plans for development, and (c) from other known accumulations that are anticipated to be developed in the near future for a range of oil and gas prices. Additional goals are to estimate the minimum economic field size (MEFS) at various locations on the ANS and to evaluate the economics of facility sharing. The economic focus is on individual resources at the pool level and relies on historical pool performance to forecast oil, water, and gas production. When historical data are not available, analogous pool characteristics are used. The empirical dimensionless variable methodology is used for water and gas rate forecasts and this capability facilitates the comparison of oil, water, and gas production for the various pools and the aggregated oil, water, and gas production for a unit or by production facility.

S.5.5.1 Economic Model

The economic model used is a modification of the models developed for earlier economic studies of Alaska's hydrocarbon resources (Thomas, et al. 1991, 1993, 1996, and 2004). The model uses commercially available software[18] to create a deterministic discounted after tax, cash flow model of oil and gas development under state of Alaska, federal, and local government tax and royalty rules and environmental regulations. The model provides a detailed treatment of Alaska petroleum tax law and has been refined from previous studies.[19] The financial analysis relies on a standard data file describing each project: the oil and gas price tracks, TAPS and ANS field pipeline tariffs, estimated AGP tariffs, marine transport rates, estimated variable and fixed operating costs, resource and production characteristics, and other inputs to evaluate

[18] Interactive Financial Planing System (IFPS), Comshare (U.S.), Inc., Ann Arbor, MI.
[19] The Petroleum Profits Tax (PPT) signed into law by the Governor of Alaska on August 19, 2006 is not analyzed.

project economics. Economic model outputs include a pro forma statement and a detailed report on per barrel metrics or other customized reports.

No attempt is made to model the economic performance of an individual working interest owner; instead, the focus is on the aggregated economic performance of each pool at 100% ownership.

A base discount rate of 10% is used to calculate a cumulative present worth (PW). A cumulative PW of zero at the economic limit indicates that the project will provide a 10% rate of return for the fixed and variable costs and price scenarios. Thus, a positive PW at the economic limit indicates a capital return in excess of the discount rate, unrisked.

The economic analyses presented are un-risked because insufficient geoscience and business data are publicly available for a robust risking exercise. An un-risked approach may not reflect actual project investment hurdles required by ANS operators and investors, and a 10% discount rate may not be sufficient for industry to commit to a project development. Therefore, sensitivities to the discount rate are examined as a proxy for risk at discount rates of 15%, 20%, and 30%.

Geophysical, geologic, and exploration (GG&E) costs are project specific, including lease acquisition and lease bonus, lease rentals, geophysical surveys and interpretation, staff time and resources, the cost to prepare a location and drill an exploration well. While, these costs are difficult to obtain without access to proprietary company financial and lease data, they can be estimated. In this analysis, historical GG&E and lease acquisition costs for currently producing pools are sunk costs and are excluded from economic modeling and amortization. GG&E costs are estimated for the MEFS analysis.

Currently producing pools may have some historical carryover tax effects and these are modeled over the historical development and production time period to quantify the year-end 2004 property tax basis, unamortized intangible drilling costs, and state and federal tangible property book value for depreciation calculations. This provides economic continuity and consistency for depletion, depreciation, and amortization (DD&A). Project capital financing is assumed to be 100% equity with no debt financing or financial leverage.

New project development will have considerable investment activities occurring prior to the start of production. This results in a period of time in which project capital is being invested before a project's income cash flow starts for a period of economic and technical risk. This lead time varies with the project but can run from three to ten years depending on the distance from available infrastructure, production facility access and fluid phase constraints, size of the discovered pool or field and other factors.

The economic model uses a discounted after-tax cash flow analysis to conduct the analysis and reporting including a pro forma statement of the operating and tax structure of the study pools. A project cash flow statement for producing petroleum assets contains many separate line items, comprising three general categories; revenue and operating expenses, state taxes and credits, and federal taxes and credits, as shown:

Gross Revenue = Production Rate * Wellhead Price

Net Revenue = Gross Revenue – Royalty

Net Operating Revenue = Net Revenue – Operating Costs

State Taxable Income = Net Operating Revenue – Allocated Overhead – Interest Expense – Dry Hole Expense – Production Taxes (severance and ad valorem) –State Depreciation – Expensed Intangible Drilling Costs – Amortization

Income after State Taxes = Income before State Taxes – State Income Taxes + Exploration Tax Credits

Federal Taxable Income = Income after State Taxes + State Depreciation – Federal Depreciation

Net Income after taxes (Profit) = Income before Federal Taxes – Federal Income Taxes

Net After-Tax Cash Flow = Net Income after taxes (Profit) – Investment + Non-Cash Deductions (i.e., Depreciation, Expensed Intangible Drilling Costs, Amortization, and Depletion)

Two cash flows are important for financial analysis and optimization: (a) net income after taxes (or profit), which is a direct measure of the return on capital generated from the investment, and (b) net after-tax cash flow, which is a measure of the residual cash flow available to the investor. In this analysis, the determination of ERR and revenues are based on the year when net operating revenue becomes negative.

Two reports are created by the economic model for each pool or field, a pro forma cash flow statement and a statement of the oil, gas, and water production and economic results on a per barrel of oil basis. These reports are used to check values, examine the income and investments, and to generate standard economic metrics on a per barrel basis. Descriptions and examples of pro-forma statements are in Appendix 3-A of the report.

S.5.5.2 Economic Input data

Production forecasts: Historical pool production is from the AOGCC electronic production database. The database contains individual well records for monthly oil, gas and water production from April 1969 through December 2004. This information is used for calculating derivative data such as active well counts, daily production, gas-oil ratio (GOR), and water-cut trends. Production data for producing pools are presented in Section 3.3 of the report.

In instances where historical production data are not available or adequate for decline curve analysis, reserves are based on published estimates when available or on geology (i.e., relying on volumetric estimates of OOIP and OGIP 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 and duration of the plateau determined by the TRR. These forecasts are described in Section 3 of the report

Model Resource Parameters: Primary resource parameters are the OOIP, OGIP, oil gravity, initial GOR, the estimated total recovery factor [primary, secondary, and enhanced oil recovery (EOR)], and other. The recovery factor varies by field depending on the well spacing, previous oil recovery operations, well configuration (vertical, horizontal, multi-lateral), and intrinsic geologic, reservoir, and fluid properties. The individual pool forecast of TRR liquid volumes (crude oil and NGLs) are used in the economic model and are described by pool or field in Section 3.3.

Oil Prices: Uncertainty in forecasting future oil prices is high because of current high oil prices and persistent oil price volatility. An oil price forecast is still necessary to estimate future project cash flows and provide a common basis for comparing the relative economic merit of competing investment opportunities under comparable conditions.

Figure S.11 compares historical ANS West Coast and WTI prices over the time period from January 1988 to December 2004. The differential between the price of benchmark West Texas Intermediate (WTI) and the ANS spot price has averaged $2.32/barrel from 1988 through 2006. From 2004 through 2006 the WTI-ANS differential has averaged $2.68/barrel. Price volatility has clearly been increasing since 1996. Figure S.11 also includes the DOE Energy Information Administration (EIA) Annual Energy Outlook 2006 forecast (reference case) and the Alaska Department of Revenue (ADOR) Fall 2006 forecast.

Four flat price decks (nominal dollars) of $25/barrel, $35/barrel, $50/barrel, and $60/barrel for ANS West Coast prices are expected to bracket the oil price range applicable to North Slope crude as illustrated in Figure S.11. Prices are escalated by the general inflation factor of 2.4% and there is no real oil price appreciation. This range roughly brackets the range of oil prices and the impact on future reserves and on state, federal government, and unit owner’s revenue streams.

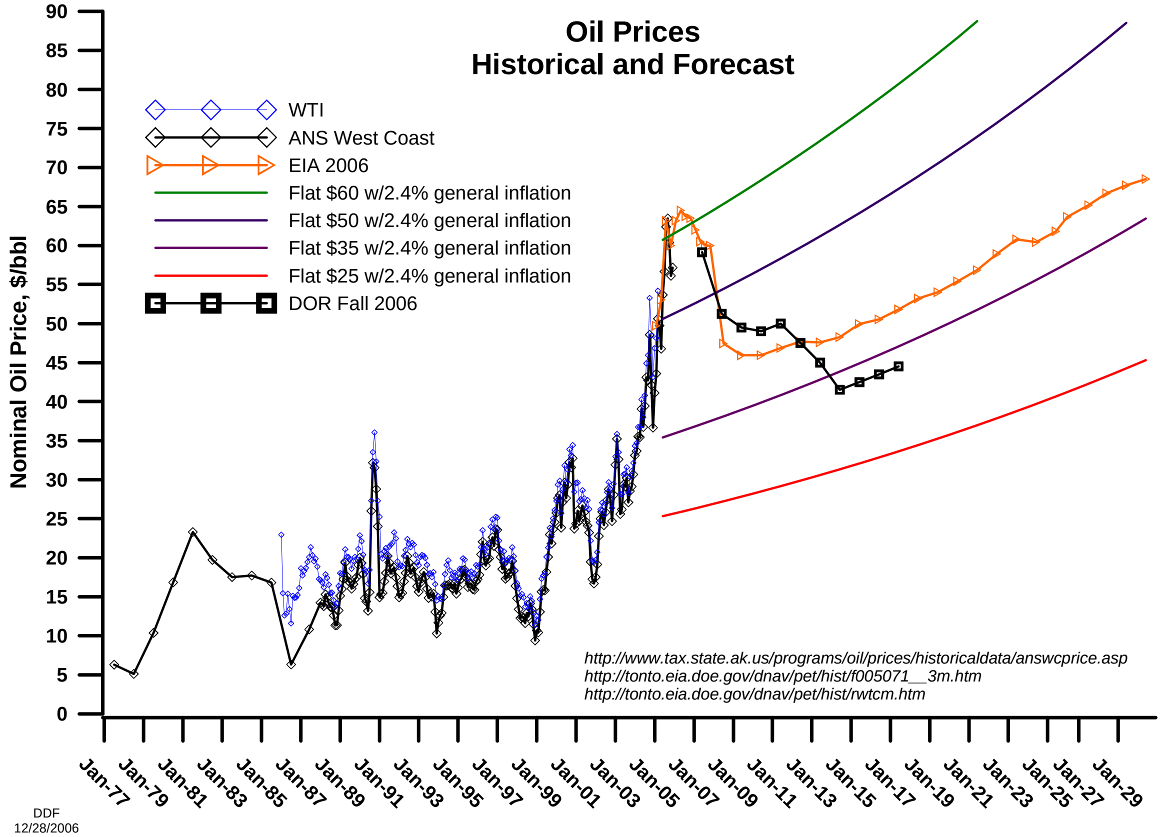

Figure S.11. Comparison of historical oil prices and oil price forecasts (AEO, 2006; ADOR, 2006).

Gas Prices: Historical average U.S. wellhead, Henry Hub spot, Cook Inlet prevailing natural gas prices, and WTI oil spot prices (converted at 8 MCF/bbl or 8,000 MBTU/bbl) are shown in Figure S.12. The recent history indicates that oil and natural gas prices are not at direct BTU parity over the last few years and a review of the last 20 years indicates an 8:1 BTU price relationship. Hence, for this assessment, the four natural gas price forecasts used are the BTU equivalent of the four ANS West Coast oil price forecasts at eight-to-one.

Wellhead prices: ANS wellhead oil prices are the ANS West Coast prices less transportation costs, comprised of marine transportation costs, TAPS tariffs, and field pipeline tariffs. An oil quality factor adjustment is applied (Section 3.2.1.5) to provide a mechanism for the different quality of oil delivered to TAPS. Wellhead gas prices were estimated using a yearly gas pipeline tariff and netback natural gas prices to the wellhead.[20] The tariff is calculated using an economic model for a gas pipeline project to Chicago (see Section 3.2.1.6) (DOE, 2006).

[20] The Alaska Gas Pipeline (AGP) is expected to be a high pressure dense phase line that will transport enriched natural gas containing significant quantities of ethane, propane, butanes, and pentane in addition to methane. An average heating value content of 1,200 to 1,500 BTU/standard cubic foot (scf) (ANGDA, 2005) is expected. At this stage of planning, the quantity and value of the non-methane hydrocarbons are uncertain and are not explicitly included in the economic evaluations.

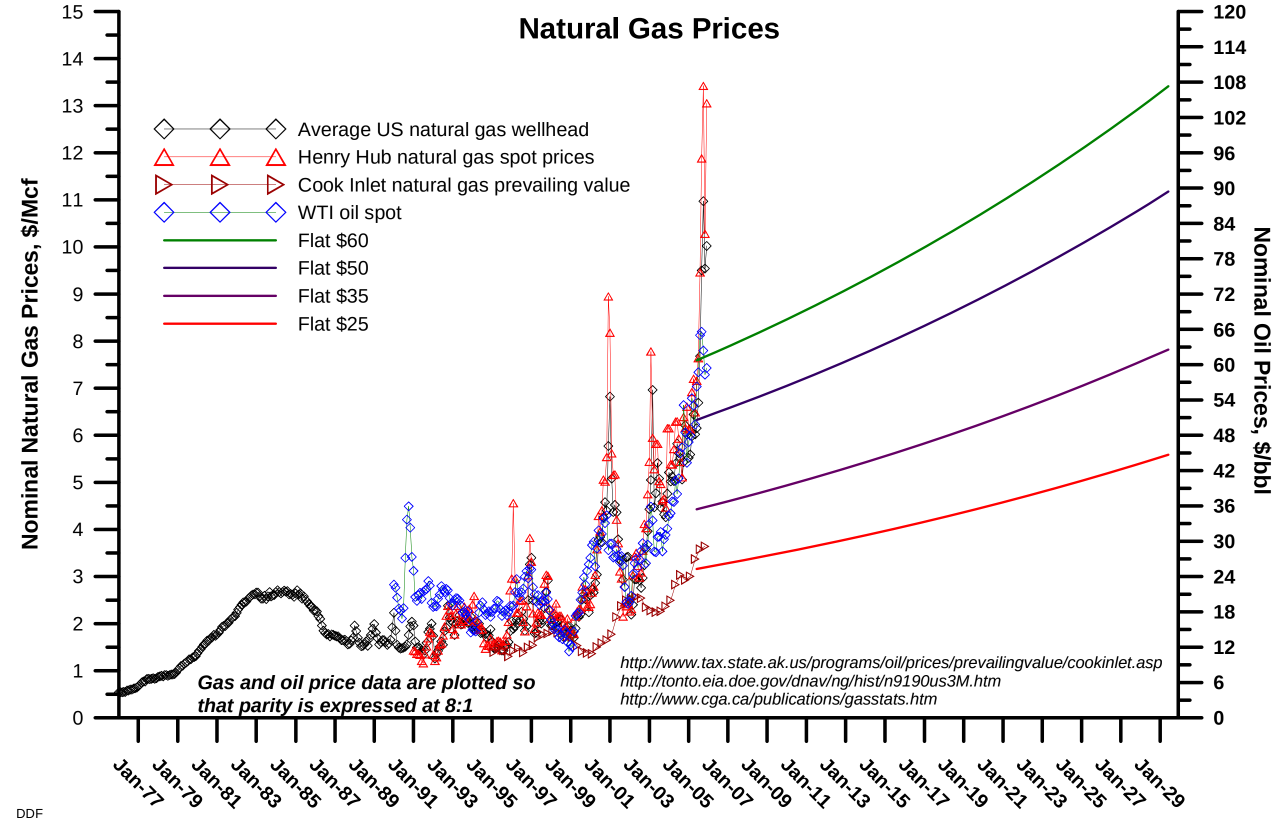

Figure S.12. Comparison of historical natural gas prices and price forecasts.

Oil Transport Costs and Quality Adjustments: The state of Alaska publishes the Alaska Location Differential (formerly called the Marine Transportation Deduction) that netbacks the ANS West Coast oil prevailing value to the Valdez tanker port (shown in Table S.7.) Marine transportation costs are escalated at the general inflation rate for the out years.

Table S.7. Historical and forecast marine transport costs (nominal dollars). (Source: ADOR, 2005)

Year	$/barrel	Year	$/barrel
2000	1.32	2009	1.93
2001	1.29	2010	1.98
2002	1.39	2011	2.03
2003	1.79	2012	2.08
2004	1.66	2013	2.13
2005	1.52	2014	2.18
2006	1.78	2015	2.23
2007	1.83	2016	2.28
2008	1.88		

TAPS is a 48-inch common carrier crude oil pipeline owned and operated by five companies, known as the TAPS Carriers: BP Pipelines (Alaska) Inc.; ExxonMobil Pipeline Company; ConocoPhillips Transportation Alaska, Inc.; Koch Alaska Pipeline Co., LLC; and Unocal (Chevron) Pipeline Company. TAPS tariffs are filed on a calendar year basis, with new tariffs taking effect January 1 each year. The 2005 TAPS tariff is $3.25/barrel (FERC, 2004) and the TAPS tariff forecast used by ADOR (2005) is presented in Table S.8. The TAPS tariff is escalated at the general inflation rate for the out years.

Table S.8. Forecast TAPS tariff. (Source: ADOR, 2005)

Year	TAPS Tariff ($/barrel)	Year	TAPS Tariff ($/barrel)
2006	3.66[21]	2012	3.51
2007	3.75	2013	3.66
2008	3.64	2014	3.83
2009	3.59	2015	3.89
2010	3.56	2016	3.99
2011	3.58		

Field pipeline tariffs are posted by the operators. Oil that traverses several field pipelines is assessed a field tariff for each pipeline segment. Field pipeline tariffs are presented in Table S.9.

Table S.9. Field pipeline tariffs, $/barrel.

Field	Tariff ($/barrel)	Notes
Alpine	0.66	To Kuparuk pipeline
Badami	0.24	To TAPS Pump Station #1, (RCA P-04-2)
Endicott	0.68	To TAPS Pump Station #1
Kuparuk	0.19	To TAPS Pump Station #1
Milne Point	0.24	To intersection with Kuparuk pipeline (RCA P-04-3)
Northstar	1.31	To TAPS Pump Station #1

The oil quality of the different fields varies from heavy to light oil and is reflected in the American Petroleum Institute (API) gravity value. Historically, a quality bank has been used by TAPS to adjust the value of the different oils and compensate for differentials in the value of shippers' oil commingled in the pipeline. Variation from the specified API gravity results in a positive price adjustment for crude oils with a higher API gravity and a negative price adjustment for crude oils with lower API gravity. The quality bank adjustment used is $0.0364 per 0.1°API referenced to a gravity of 28°API (ConocoPhillips Alaska, 2006). This approach is a simplification of the current methodology, which is based on a distillation methodology.[22]

Gas Tariffs: The economic evaluation of major gas sales assumes delivery of ANS gas to Chicago and required an estimate of natural gas tariffs for the 3600-mile route. This tariff calculation uses a full life cycle cost basis that includes the capital cost of; the pipeline, gas

[21] For comparison purposes, Alaska Department of Revenue 2006 Fall Forecast tariffs are $4.06/bbl for 2006, $4.38/bbl for 2007, $4.11/bbl for 2008 with 2009 through 2017 lower by about $1.00/bbl than the tariffs contained in the 2005 Forecast. These forecasts were not available for use in this analysis.

[22] The quality bank methodology has been the topic for litigation and FERC hearings over a number of years. A decision was made by FERC October 20, 2005 affirming an administrative law judge's initial decision compensating shippers according to the quality of the crude oil delivered to TAPS. The valuation method uses a distillation method for valuing the various components of the crude oil and is separated into components such as butane, propane, naphtha and residual. Market values are assigned to each cut and the value of a crude oil stream is determined by the relative weighting of the cuts.

conditioning plant on the North Slope for the removal of CO_2 and other contaminates, compressors, and estimated decommissioning costs after the useful life of the pipeline. The capital structure assumes 50% equity and 50% debt and a weighted average cost of capital of 9.97%. The annual O&M costs are assumed to be 2.5% of the installed capital, dismantlement costs are 2% of the installed capital.

Capital costs for a 52-inch pipeline project were estimated at $21 per diameter-inch foot, $1.6 billion for compressors, and $2.4 billion for a gas conditioning plant at the pipeline inlet (2005$) for a total project cost of $24.8 billion (2005$). The annual cost of service is the sum of the annual operating costs, capital depreciation, the regulatory allowed return on installed capital, decommissioning costs (as a sinking fund), ad valorem taxes at 2%, and state and federal income taxes at 9.4% and 34%, respectively . The annual tariff is the cost of service divided by the annual pipeline volume (DOE, 2006). This tariff calculation is described in greater detail in Appendix 3-B of the report.

Figure S.13 depicts gas tariffs as a function of flow rate for the 52-inch pipeline. The tariffs shown are the 12-yr average from 2015 to 2026 in 2005$.

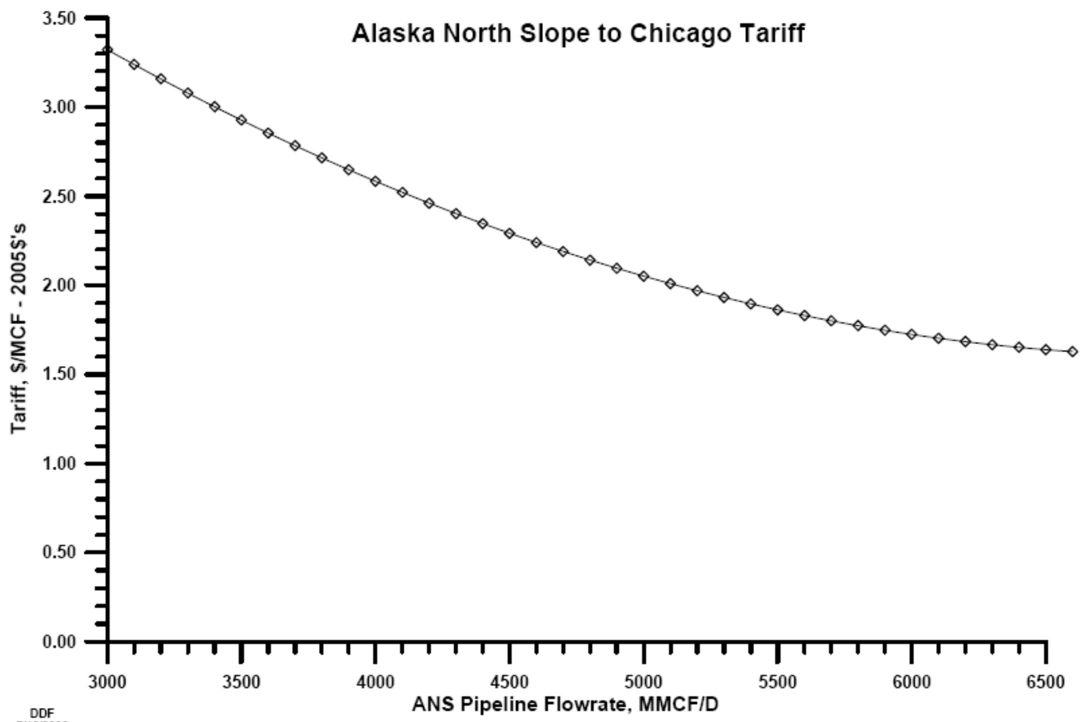

Figure S.13. ANS 52-inch pipeline tariff (2005$).

Yearly tariffs for a 4.5 BCFPD flow rate are shown in Table S.10. For the out-years beyond 2026 the gas tariffs are escalated at the general inflation rate of 2.4% annually. Yearly tariffs vary as a result of depreciation schedules, property taxes, and income taxes and are used to netback natural gas prices to the wellhead.

Table S.10. Alaska Gas Pipeline tariff by year, 2005$.

YEAR	2005$
2015	2.599
2016	2.931
2017	2.784
2018	2.647
2019	2.517
2020	2.394
2021	2.278
2022	2.169
2023	2.065
2024	1.968
2025	1.876
2026	1.788

Royalty is a fraction of the gross wellhead value that is paid by the lessee to the lessor for mineral production from a lease. The customary royalty for ANS production is 12.5% (1/8) while there are some leases having a 16.67% royalty or a net-profits interest royalty. Ninety percent of federal oil and gas royalty payments are returned directly to the state of Alaska.[23]

Gas and water production forecasts are required to estimate the variable operating cost and examine facility fluid phase constraints (oil, water, and gas). One difficulty of forecasting future oil, water, and gas production for ANS fields is the wide variation of reservoir properties, fluid properties, well design, improved oil recovery processes, and other geologic, engineering, and operational considerations. A complete analysis, which would require access to reservoir engineering data (well tests, well completions, recovery technologies, etc.), and use detailed reservoir simulation models for each pool, is not feasible. A method to reduce the complexity of the analysis by transforming the pool-specific production data to dimensionless variables was developed (Appendix 3-C). Pools with similar formations, reservoir fluids, and displacement mechanisms are observed to have similar production responses when reduced to dimensionless variables. When sufficient pool data are not available, forecasts are made using information from analogous reservoirs.

Well Counts: The number of active production and injection wells at year-end 2004 is available from state production records. New wells in the economics model are added to the number of active wells based on the specified fraction of injection and production wells. The average well production rate is calculated by dividing the yearly production by the number of active production wells and is used for the economic limit factor (ELF) in the determination of severance taxes, and variable operating costs. Well attrition is assumed to increase with time from between 2.5 and 5%/year of the active production and injection wells, accounting for well abandonment and mechanical failure and is used to model well abandonment or mechanical failure or both during the life of the field. Thus, in the absence of new drilling, the operating well count will eventually decline, mimicking field operations.

[23] http://www.blm.gov/ak/ak940/fluids/oil-gas2.html.

Operating costs consist of both fixed and variable components. The average North Slope fixed cost is assumed to be $1,000,000 per well per year (2005$). The fixed cost is based on a recent study that estimated Alaska operating costs (fixed plus variable) at $1.761 million per well (2000$s) (NPC, 2003). This costs was escalated to 2005$s at 3.54%/year yielding $2.096 million per well per year total operating costs using the Bureau of Labor statistics Producer Price Indices (PPI), oil and gas services component. As discussed in the section on inflation, the extreme volatility in the PPI oil and gas components makes estimating the total operating cost per well uncertain. There is a dearth of data to refine the total operating cost assumptions. These costs are reduced near the end of a field's economic life as a function of the recovery factor to approximate the actions a prudent operator would undertake to reduce costs as a pool's production declines to extend the economic limit. Variable costs are those component that are a linear function of the production rate, such as lifting costs on a per-barrel-fluid-lifted basis (crude oil and water production) or a facility-sharing fee on produced fluids. The average lifting cost for North Slope production is assumed to be $0.50 per barrel of fluid for conventional oil pools and $0.75 per barrel of fluid for viscous oil pools because associated solids production increases costs.

Economic Limit: There are several ways to estimate the economic limit. This study assumes the economic limit occurs when total operating costs exceed net revenues. The total operating costs include the lifting costs, facility cost-sharing fees, well workover costs, and fixed operating costs.

Capital expenditures: Capital expenditures include a broad range of costs for exploration activities, delineation and development wells, offshore platforms, production facilities, field pipelines, other infrastructure related investments, and required regulatory costs. Capital costs are either tangible or intangible and are treated differently for tax purposes. Project development costs are scheduled on a pool-by-pool basis. A review of the trade literature related to North Slope development was made to identify general cost ranges for development wells, production facilities, and pipelines.

Investment costs are year-end 2004 dollars and are inflated to then-current-year dollars using a general inflation rate of 2.4%. Costs for platforms, production facilities, and pipelines are 100% tangible, development wells costs are 30% tangible, and exploration well costs are 10% tangible, with the balance as intangible costs. Intangible drilling costs are 70% expensed in the year incurred and the remaining 30% are amortized over 60 months.

Facility costs: Production facility costs are estimated for recent developments based on a dollar per BOPD peak production capacity basis. An analysis of the property tax base of the North Slope Borough assessment for 2004 suggests facility costs for grassroots projects are from $7,000 to $10,000/BOPD-peak-production-rate. The $10,000/BOPD factor is used for new development projects. Pipeline costs per foot are estimated to be $20 per diameter-inch-ft for onshore projects and $40 per diameter-inch-ft for offshore. An algorithm is used to size pipelines and estimate the associated capital costs for new developments or satellite accumulations (See Appendix 3-E).

Well Costs: The wide range of development wells used (vertical, horizontal, multilateral, coiled tubing drilling) makes it difficult to estimate the cost for a "standard" development well or even what constitutes a "standard" well. Development information from recent fields suggests the standard well in the future will be either horizontal or multilateral completions with a development well cost of at least $8.5 million. The drilling investment schedule is developed from the number of future development wells provided in Section 3.3, anticipated well productivity, and development well cost. The development drilling costs reflect the differences in the characteristics and location of each pool and the development well design used. ANS well cost estimates by pool used in the economic evaluations are listed in Table S.11.

Table S.11. Well cost estimates for ANS pools.

Pool	Estimated Well Cost, 2005$ thousands	Note
Alpine	8,500	Onshore
Alpine West	11,000	Onshore
Ataruq	5,000	Onshore
Aurora	7,500	Onshore
Borealis	7,500	Onshore
Endicott	2,500	Offshore
Fiord	11,000	Onshore
Gwydyr Bay	8,500	Onshore/Offshore
Kuparuk River	1,600	Onshore
Liberty	10,000	Offshore
Lisburne	2,500	Onshore
Lookout	11,000	Onshore
Meltwater	7,500	Onshore
Midnight Sun	8,500	Onshore
MPU Kuparuk	2,500	Onshore
MPU Schrader Bluff	11,000	Onshore
Nanuq	10,000	Onshore
Niakuk	2,500	Onshore/offshore
Nikiatchuq	7,500	Offshore
Northstar	10,000	Offshore
Oooguruk	10,000	Offshore
Orion	6,000	Onshore
Placer	6,000	Onshore
Point Thomson	15,000	Offshore
Polaris	7,500	Onshore
Prudhoe Bay	2,500	Onshore
Pt. McIntyre	2,500	Onshore
Sambuca	6,000	Onshore
Sandpiper	10,000	Offshore
Sourdough	10,000	Onshore
Spark	11,000	Onshore
Tabasco	6,000	Onshore
Tarn	7,500	Onshore
Tuvaaq	10,000	Offshore
West Sak	8,000	Onshore

Alaska petroleum taxation: Alaska petroleum taxation includes capital asset depreciation, property tax (ad valorem), oil and gas severance tax, income tax, and exploration tax credits. Severance taxes are levied on all oil and gas production from all state onshore property and adjacent state waters. The existing severance tax system using the economic limit factor (ELF) is used although a different tax structure (Petroleum Profits Tax) was passed by the Alaska State Legislature in August 2006. The details for applying the new tax structure are still being developed at this time. See Section 3.2.1.12 for a complete description of the methodology used in this assessment.

Federal petroleum taxation: Federal income tax rate is 34%. The methods used to arrive at federal taxable income are described in Section 3.2.2.13.

Discounted cash flow analysis is an accepted mineral and petroleum industry method and is the economic evaluation tool used in the study. The decision making process typically used by industry is described in Thomas et al. (1993, Section 1.2). The present worth (PW) of a project is the cumulative after tax net cash flow generated from the project's time-sequenced revenues using a company's internally developed price forecast less expenses discounted to current year dollars; i.e., 2005$ in this assessment. For example, a project that produces exactly a 10% return is defined as $PW_{10} = 0$, meaning the investment earns a 10% return, after tax, measured in current-year dollars. Industry decision-making will likely involve other economic and business criteria and different economic metrics with risking based on internal assessment of technical, political, and economic risk.

A 10% discount rate is used for this assessment and is assumed to be representative of the current investment climate and the unrisked, real cost of capital. Sensitivities are run with discount rates at 15, 20, and 30%. The discount factor is calculated using an unrisked annual discrete formulation with mid-year timing and may not reflect actual project investment hurdle metrics used by North Slope operators. Fundamental components in any investment decision analysis are the production forecast, commodity price forecast, fixed and variable operating costs, fiscal and regulatory regime, and the anticipated inflation rates.

Inflation: A forecast inflation rate of 2.4% per annum is used for general costs, transportation costs, and oil prices; a 3.5% per annum is used for drilling and operating costs. The general inflation rate is consistent with the average Gross Domestic Product (GDP) deflator for the last five years. The drilling and operating cost inflation is based on the PPI, "support activities for oil & gas operations" index, which has averaged 3.54% per annum over the last 20 years with extreme volatility. All costs are inflated to then-current (nominal) dollars from a year-end 2004 base using mid-year escalation. The increasing volatility of the two indices over the last five years suggests the 3.5% per annum inflation rate may understate the sector inflation rate, as shown in Figure S.14. This figure presents the six-month moving-average monthly change in the PPI indices. The WTI oil price is presented for comparison with the cost indices.

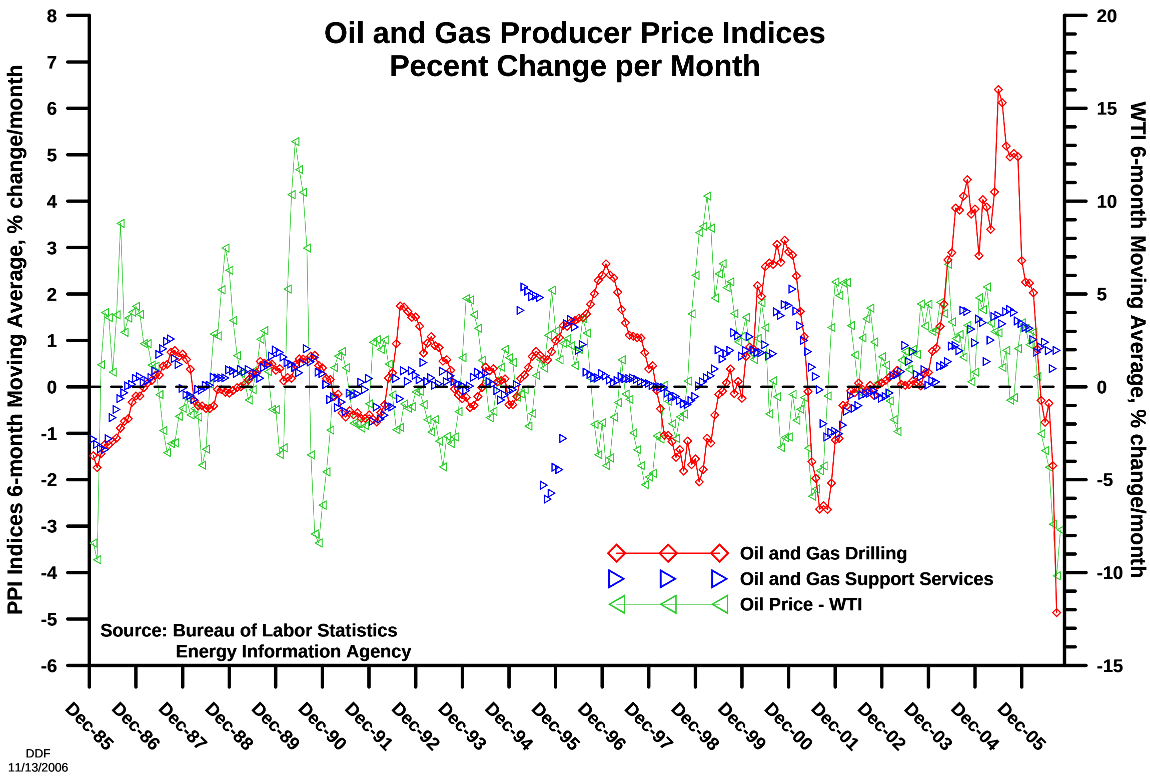

Figure S.14. Monthly change in Oil and Gas Producer Price Indices compared to WTI.

S.5.6 Engineering and Economic Analysis of ANS Fields–Without Major Gas Sales

This report presents engineering and economic evaluations of ANS fields both with and without major gas sales. Sections 3.3, 3.4, and 3.5 of the full report describe the engineering and economic evaluations of three categories of fields in the absence of major gas sales: (1) currently producing fields, (2) fields with pending or announced development plans, and (3) known fields with potential for development in the near future. A brief description of each pool is provided and the forecasts for the petroleum liquids (crude oil, condensate, and NGLs), gas, water, and well counts used in the economics evaluation are presented. An example of pool production history and forecasts is shown in Figure S.15 for the Kuparuk River Unit.

In the full report, in addition to the figures such as these for each pool and field, data tables include total historical production through December 31, 2004, total forecasts of future and ultimate recoveries for the four price cases, and the economic results showing total investment, total operating costs, state royalty and taxes, federal taxes, and industry income at the basic 10% per annum discount rate.

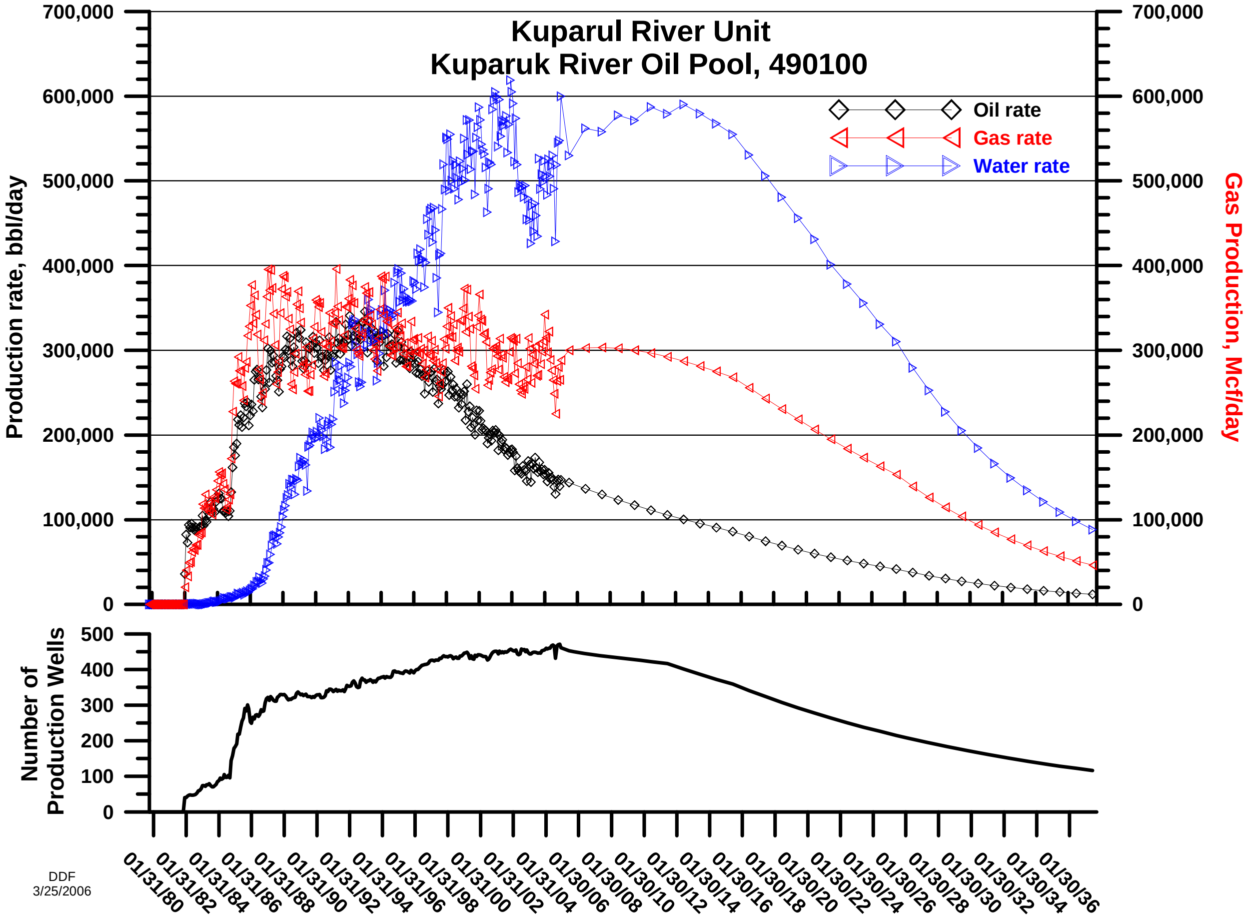

Figure S.15. Kuparuk River Unit–Kuparuk pool production history and forecasts.

Table S.12 shows OOIP, TUR, TRR, and production through December 31, 2004 for each pool by category. The TRR estimates for these fields total 6.413 BBO.

Table S.12. ANS Fields–Currently Producing Fields, Fields with Development Plans, and Fields with Near-Term Development Potential.

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
CURRENTLY PRODUCING FIELDS					
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	25,000,000	13,483,252	11,143,715	2,339,537	0.539
Aurora Participating Area (PA)	100,000	45,810	11,397	34,413	0.458
Borealis PA	263,000	105,189	30,849	74,340	0.400
Midnight Sun PA	60,000	21,048	11,343	9,705	0.351
Orion PA Phase I	92,000	21,735	2,310	19,690	0.236
Polaris PA	303,700	68,440	3,539	64,901	0.225
Lisburne PA	3,000,000	194,619	153,621	40,998	0.065
Niakuk PA	200,000	99,323	81,223	18,100	0.497
North Prudhoe PA	12,000	2,070	2,070	0	0.173

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
West Beach PA	15,000	3,591	3,591	0	0.239
Point McIntyre PA	800,000	506,413	384,103	122,310	0.633
Duck Island Unit (DIU)					
Endicott PA	1,059,000	533,952	447,612	86,340	0.504
Eider PA	13,000	2,687	2,687	0	0.207
Sag Delta North PA	16,000	8,059	8,059	0	0.504
Northstar Unit (NU)					
Northstar PA	284,700	235,500	67,215	168,260	0.591
Badami Unit (BU)	300,000	4,347	4,347	0	0.014
Kuparuk River Unit (KRU)					
Kuparuk River IPA	5,690,000	2,763,120	1,974,540	788,580	0.486
Meltwater PA	132,000	42,100	7,658	34,442	0.319
Tabasco PA	99,500	21,570	9,735	11,835	0.217
Tarn PA	255,000	125,313	64,603	60,710	0.491
West Sak PA	275,000	62,365	15,631	46,734	0.227
Milne Point Unit (MPU)					
Kuparuk River IPA	525,000	264,600	180,286	84,314	0.504
Sag River PA	62,000	1,589	1,589	0	0.026
Schrader Bluff PA	1,333,400	321,326	38,126	283,200	0.241
Colville River Unit (CRU)					
Alpine Oil	900,000	539,900	137,639	402,261	0.600
Total–currently producing fields	**40,790,300**	**19,477,918**	**14,787,488**	**4,690,670**	**0.478**
KNOWN FIELDS WITH PENDING/ANNOUNCED DEVELOPMENT PLANS					
Kuparuk River Unit (KRU)					
Placer PA	110,000	36,620	0	36,620	0.333
West Sak Additional (Pad IE &IJ)	1,225,000	285,000	0	285,000	0.233
Colville River Unit (CRU)					
Fiord PA	150,000	53,940	0	53,940	0.360
Nanuq PA	150,000	43,920	0	43,920	0.293
Alpine West PA	150,000	53,630	0	53,630	0.358
Lookout Satellite	150,000	53,906	0	53,906	0.359
Spark Satellite	150,000	53,906	0	53,906	0.359
Prudhoe Bay Unit (PBU)					
Prudhoe Bay, Orion Phase II & III	978,000	228,970	0	228,970	0.234
Prudhoe Bay, Polaris Phase II & III	446,300	98,500	0	98,500	0.221
Oooguruk Unit (OU)	155,500	71,600	0	71,600	0.460
Nikaitchuq Unit (NU)	485,700	175,200	0	175,200	0.361
Liberty Unit (LU)	271,000	125,000	0	125,000	0.461
Gwydyr Bay Unit (GBU)	150,000	53,870	0	53,870	0.359
Total–Fields with pending/announced development plans	**4,571,500**	**1,334,062**		**1,334,062**	**0.337**

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL					
Sandpiper	430,000	151,502	0	151,502	0.352
Sambuca	57,500	20,700	0	20,700	0.360
Tuvaaq	200,000	74,500	0	74,500	0.373
Ataruq	103,000	37,000	0	37,000	0.359
Sourdough	290,000	104,400	0	104,400	0.360
Point Thomson was not analyzed in the No-Major-Gas Sales case. The estimated technically recoverable oil is 50,000 MBO and 350,000 MB condensate. See Table S.14 for gas volumes.					
Total – Fields with Development potential	**1,074,570**	**388,102**	**0**	**388,102**	**0.361**
Total	**46,442,300**	**21,200,080**	**14,787,488**	**6,412,834**	**0.456**

The forecasts of technically recoverable oil (including crude oil, condensate and NGLs) from the ANS fields listed in Table S.12 are shown in Figure S.16. These production forecasts do not account for any economic constraints such as price or operating costs; those impacts are shown in Table S.13. The horizontal line depicting the TAPS minimum flow rate of 300,000 BOPD illustrates the impact a TAPS shutdown would have on future ANS oil production **without** additional developable discoveries or other reserve additions. If ANS production were shut down by 2025, the loss of technically recoverable oil would be about 1 BBO.

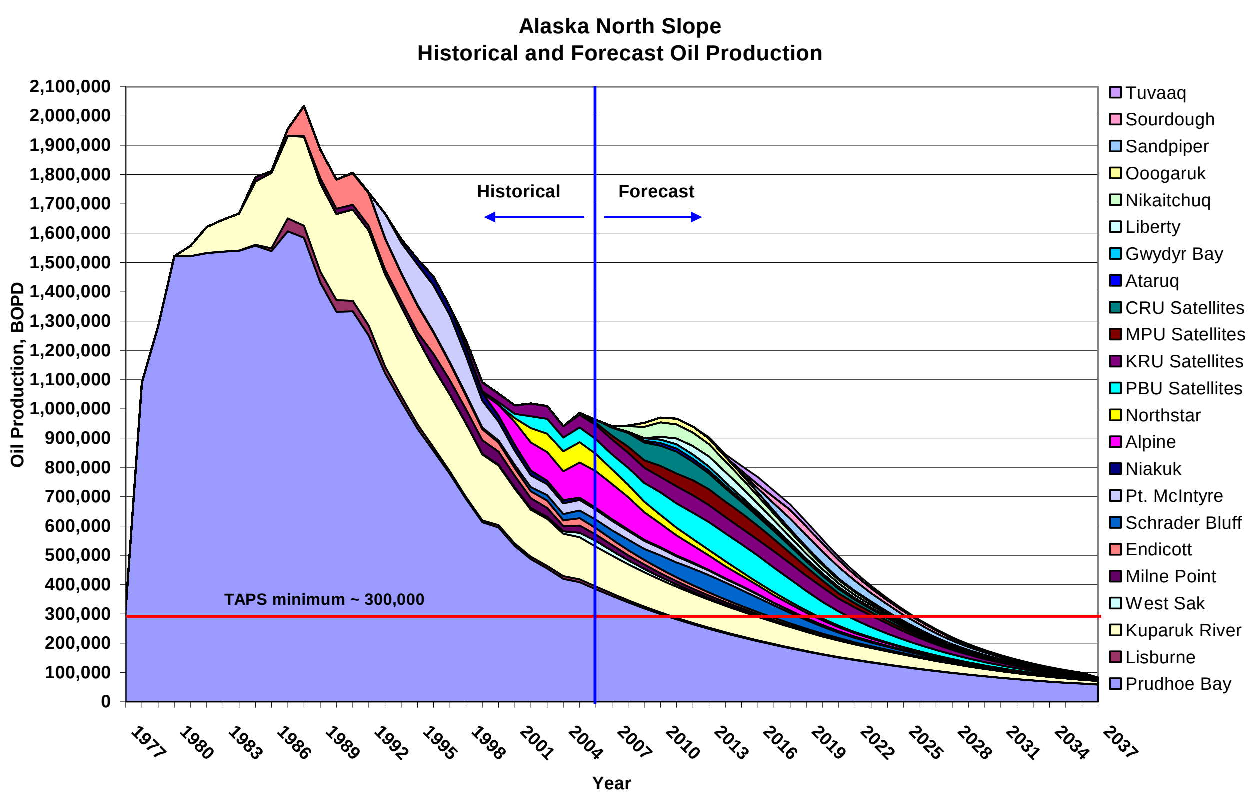

Figure S.16. Forecast of ANS technically recoverable oil without major gas sales.

Table S.13. ANS Fields–Comparison of TRR and ERR at four West Coast oil prices.

POOL/FIELD NAME	TRR (MBO)	ERR $25/bbl (MBO)	ERR $35/bbl (MBO)	ERR $50/bbl (MBO)	ERR $60/bbl (MBO)
CURRENTLY PRODUCING FIELDS					
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	2,339,537	1,985,268	2,213,277	2,213,277	2,213,277
Aurora Participating Area (PA)	34,413	26,870	30,582	31,709	32,051
Borealis PA	74,340	59,185	67,755	71,537	72,375
Midnight Sun PA	9,705	7,879	8,914	9,306	9,424
Orion PA Phase I	19,690	16,388	17,944	18,891	19,004
Polaris PA	64,901	53,633	60,141	62,621	63,373
Lisburne PA	40,998	24,998	34,280	38,110	39,337
Niakuk PA	18,100	10,018	13,102	15,449	16,161
North Prudhoe PA	0	0	0	0	0
West Beach PA	0	0	0	0	0
Point McIntyre PA	122,310	101,593	113,261	118,180	120,350
Duck Island Unit (DIU)					
Endicott PA	86,340	24035	57351	75523	78566
Eider PA	0	0	0	0	0
Sag Delta North PA	0	0	0	0	0
Northstar Unit (NU)					
Northstar PA	168,260	164,506	166,424	167,232	167,588
Badami Unit (BU)	0	0	0	0	0
Kuparuk River Unit (KRU)					
Kuparuk River IPA	788,580	704,852	776,739	776,739	776,739
Meltwater PA	34,442	28,285	31,280	32,840	33,315
Tabasco PA	11,835	11,535	11,688	11,804	11,839
Tarn PA	60,710	52,483	56,413	58,825	59,891
West Sak PA	46,734	23,582	33,857	39,627	40,920
Milne Point Unit (MPU)					
Kuparuk River IPA	84,314	19,350	40,505	61,875	69,485
Sag River PA	0	0	0	0	0
Schrader Bluff PA	283,200	210,910	242,121	260,916	267,233
Colville River Unit (CRU)					
Alpine Oil	402,261	379,845	391,119	397,011	398,796
Total – currently producing fields	**4,690,670**	**3,905,215**	**3,905,215**	**4,461,472**	**4,489,724**
KNOWN FIELDS WITH PENDING/ANNOUNCED DEVELOPMENT PLANS					
Kuparuk River Unit (KRU)					
Placer PA	36,620	32,023	34,692	35,704	36,130
West Sak Additional (Pad IE &IJ)	285,000	239,811	263,731	277,365	280,245
Colville River Unit (CRU)					
Fiord PA	53,940	47,450	50,642	52,311	52,817

POOL/FIELD NAME	TRR (MBO)	ERR $25/bbl (MBO)	ERR $35/bbl (MBO)	ERR $50/bbl (MBO)	ERR $60/bbl (MBO)
Nanuq PA	43,920	36,241	40,614	42,283	42,789
Alpine West PA	53,630	47,446	50,639	52,307	52,813
Lookout Satellite	53,906	47,446	50,638	52,306	52,811
Spark Satellite	53,906	47,592	51,304	52,720	53,148
Prudhoe Bay Unit (PBU)					
Prudhoe Bay, Orion Phase II & III	228,970	181,306	212,825	221,550	224,015
Prudhoe Bay, Polaris Phase II & III	98,500	81,107	92,650	96,998	97,729
Oooguruk Unit (OU)	71,600	54,794	63,061	68,682	69,627
Nikaitchuq Unit (NU)	175,200	124,657	170,004	170,004	170,004
Liberty Unit (LU)	125,000	96,165	110,356	120,010	122,266
Gwydyr Bay Unit (GBU)	53,870	44,694	50,443	52,473	52,923
Total–Fields with pending/ announced development plans	**1,334,062**	**1,080,732**	**1,241,599**	**1,294,713**	**1,307,317**
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL					
Sandpiper	151,502	141,657	149,249	151,502	151,502
Sambuca	20,700	19,026	19,863	20,371	20,483
Tuvaaq	74,500	1,606	70,003	73,675	73,675
Ataruq	37,000	31,279	33,474	35,142	35,646
Sourdough	104,400	83,038	95,101	101,075	101,075
Point Thomson was not analyzed in the no-major-gas sales case. The estimated technically recoverable oil is 50,000 MBO and 350,000 MB condensate. See Table S.14 for gas volumes.					
Total–Fields with Development potential	**388,102**	**276,604**	**367,690**	**381,765**	**382,381**
Total	**6,412,834**	**5,262,551**	**5,514,504**	**6,137,950**	**6,179,422**

Table S.14 shows the total investments, total operating costs and the revenues to all the stakeholders (the state and federal governments and industry) all the ANS pools and fields listed in Table S.12.

Table S.14. Aggregated Economic Results without Major Gas Sales: ANS Currently producing fields plus fields with pending development plans plus fields with development potential (ANS West Coast prices, then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	14,050,924	14,748,936	14,893,750	14,911,643
Total operating costs	64,581,995	85,969,512	93,211,618	95,879,755
State royalty	14,371,505	26,451,105	42,112,067	52,418,264
State taxes – Severance	4,751,757	7,664,591	11,702,950	14,391,161
State taxes – Income	568,146	2,111,428	4,914,352	6,849,529
State taxes – Other	3,528,477	4,054,326	4,284,509	4,336,163
State Total (Royalty and Taxes)	**23,163,009**	**40,203,961**	**62,924,068**	**77,902,472**
Federal taxes	**6,017,249**	**24,063,430**	**55,419,939**	**76,804,266**
Industry net income	**10,945,963**	**47,878,679**	**108,927,427**	**150,567,019**

Figure S.17 illustrates the state, federal, and industry revenue shares at the four price levels (in 2005$) for the aggregated results shown in Table S.14.[24] The industry share of revenues increases from 27% to 47% as the oil prices increases from $25/bbl to $60/bbl. Concurrently, the state share decreases as a percent of total revenue from 59% to 25% and the federal take increases from 15% to 24%. The column on the right shows the state total revenue share breakdown between royalty and taxes.

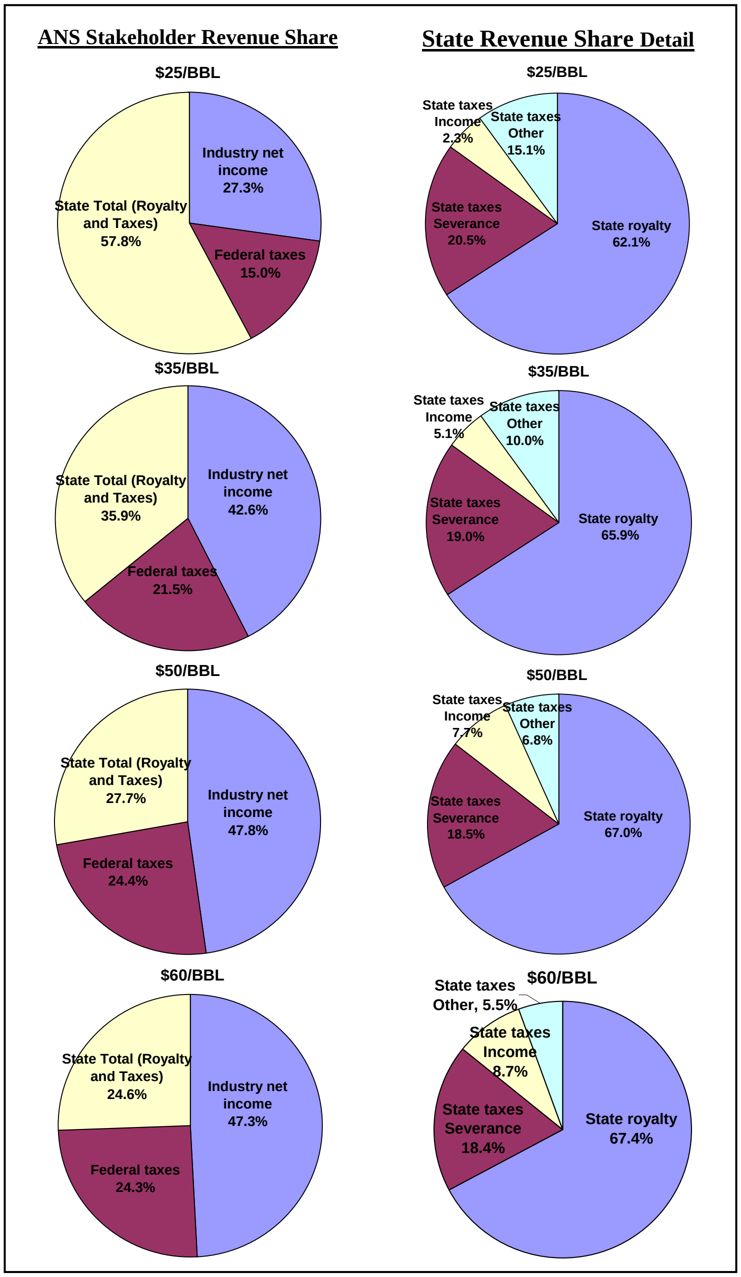

Figure S.17. ANS total economic results for industry, state, and federal stakeholders for No Major Gas Sales case (ANS West Coast prices, 2005$).

[24] These results are based on the Economic Limit Factor (ELF) Alaska petroleum tax law. The Petroleum Profits Tax (PPT) enacted by the state of Alaska in August 2006 will change the relative revenue shares and will increase the state share as oil prices increase.

S.5.7 Engineering and Economic Analysis of ANS Fields with Major Gas Sales

Activities on the ANS could change dramatically if major gas sales are initiated through the construction and operation of a gas pipeline. If the Alaska Gas Pipeline is brought on-line, the Prudhoe Bay field and Point Thomson fields are expected to initially anchor its operations. The gas reserves in PBU are currently producible as a result of the gas injection project and associated facilities constructed in the 1980s. Although no plans have been announced to develop the Point Thomson field, it is expected that production will start by 2015 to 2016. Gas sales from PBU starting in 2015 is estimated to result in the loss of about 138 MMB of oil and condensate, equivalent to about 1% of the TUR (see Section 3.7.1). No other fields should experience TRR declines as a result of major gas sales. It is anticipated that CO_2 from the PBU gas will be used for EOR. Additional gas to support a 35-yr gas pipeline project at 4.5 BCFPD (a total of 57.5 TCF) will be required in the out years. This need for additional gas (25.8 TCF) will be an impetus for exploration along the gas-prone Foothills region.

Table S.15 and Figure S.18 provide the gas disposition forecasts from PBU and PTU. A total gas sales of 31.7 TCF is estimated, 23.7 TCF from PBU and 8.0 TCF from PTU. These forecasts indicate that more than 25 TCF of additional exportable gas reserves must be developed to fully supply the 4.5 BCFPD AGP project for 35 years.

Table S.15 PBU and PTU Gas disposition.

	PBU Gas Sales Disposition		**PTU Gas Sales Disposition**	
OGIP	47.4 TCF		13.2 TCF	
Non-recoverable gas	11.5 TCF	24.3%	4.0 TCF	30.3%
Lease use, local sales, and shrinkage	9.0 TCF	19.0%	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 Net Sales Gas to AGP = 31.7 TCF				
*** PBU 12% CO_2; PTU 4% CO_2**				

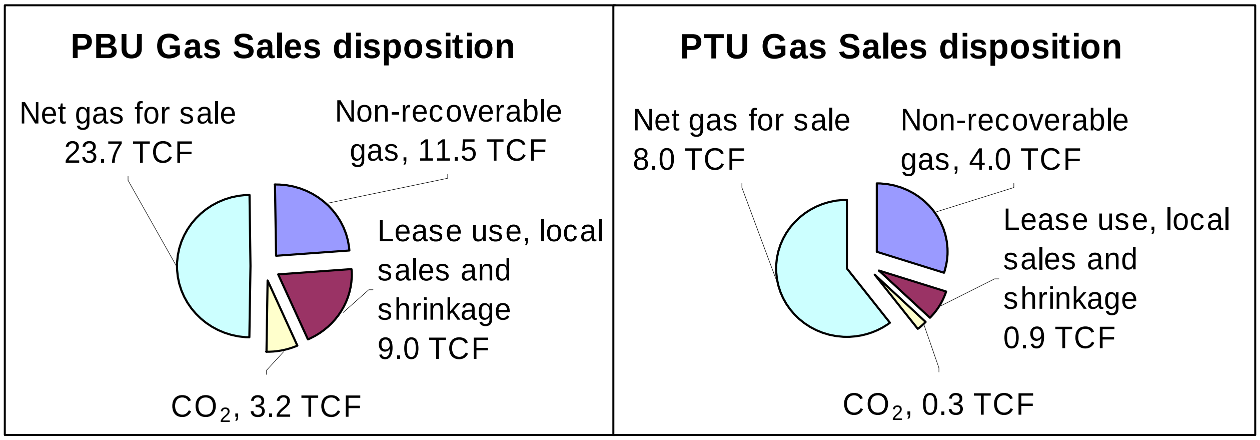

Figure S.18. PBU and PTU gas sales disposition.

Table S.16 provides the oil and gas TRR forecasts for PBU and PTU with and without major gas sales.

Table S.16. PBU and PTU TRR (1/1/2005) Forecast with Major Gas Sales

	TRR Petroleum Liquids w/o Major Gas Sales	TRR Petroleum Liquids w/ Major Gas Sales	TRR Petroleum Liquids Change	TRR Gas
PBU	**2,340 MMB**	**2,202 MMB**	**-138 MMB**	**23.7 TCF**
PTU		**400 MMB**		**8.0 TCF**
PBU + PTU	**2,340 MMB**	**2,602 MMB**	**-138 MMB**	**31.7 TCF**

Figure S.19 provides gas production forecasts from the PBU and PTU as barrels of oil equivalent (BOE), along with the oil production from all the fields listed in Table S.12. The condensate liquids and oil from PTU comprise a large wedge of the new production assumed to come on stream by 2015. The PTU liquids alone could increase the effective life of TAPS by about one year, from 2025 to 2026. The advent of gas sales from PBU and PTU represents a significant increase in the amount of hydrocarbons sent to market.

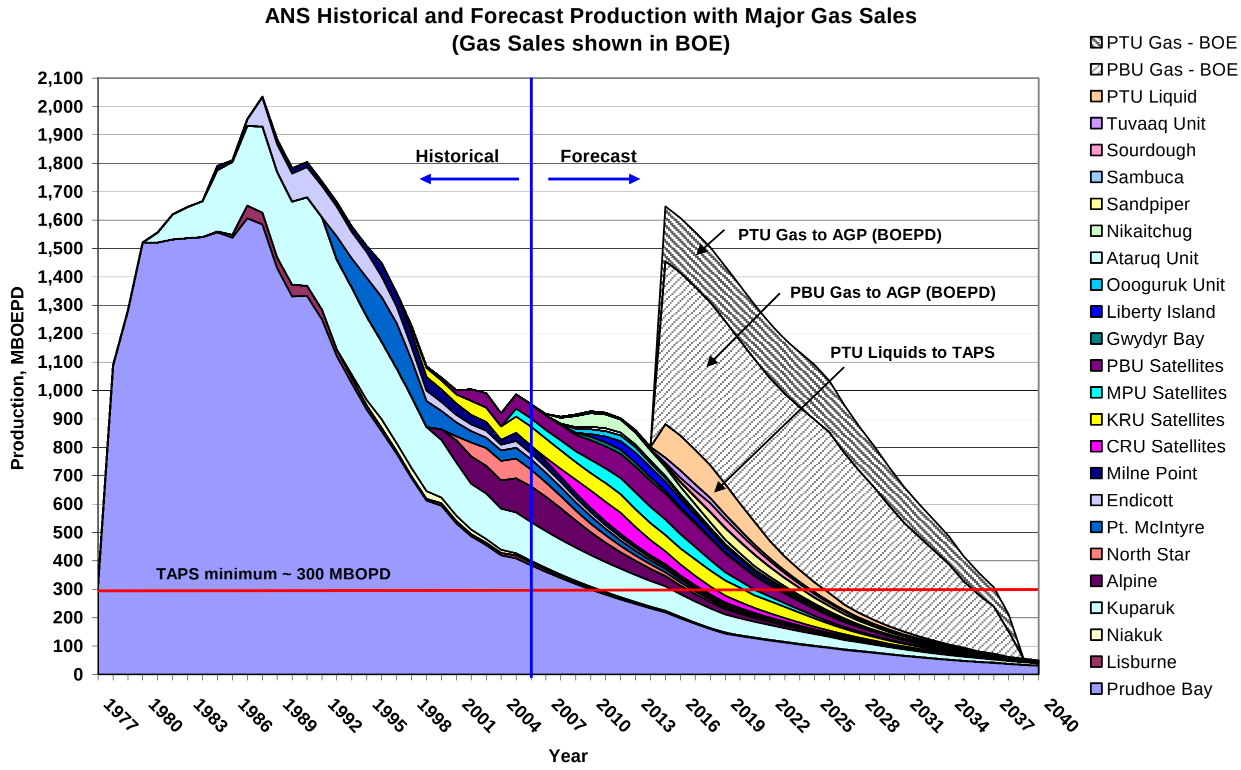

Figure S.19. ANS production with Major Gas Sales; gas in barrels of oil equivalent (BOEPD) at 6 MCF/bbl.

Table S.17 presents aggregated economic results for the pools listed in Table S.12 with gas sales from PBU and PTU, including PTU liquid sales. The costs for a gas conditioning plant at PBU and AGP are included in the analysis by the gas tariff described in Section S.5.5.2. For the PTU analysis, capital costs of gas and oil pipelines to move gas and oil to AGP and TAPS are included in the economic analysis. The AGP tariff is then applied to obtain gas wellhead values.

Table S.17. Aggregated economic results with Major Gas Sales: ANS Currently producing fields plus fields with pending development plans plus fields with development potential (ANS West Coast prices, then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	18,778,110	19,517,771	19,674,958	19,692,851
Total operating costs	73,287,620	86,968,301	95,169,489	97,914,071
State royalty	27,179,261	46,528,667	74,639,692	93,187,851
State taxes – Severance	13,179,122	21,504,474	33,955,104	42,251,502
State taxes – Income	2,232,298	5,140,479	9,912,396	13,170,494
State taxes – Other	3,958,748	4,470,671	4,701,309	4,753,371
State Total (Royalty and Taxes)	**46,549,429**	**77,644,291**	**123,208,501**	**153,363,218**
Federal taxes	**25,279,560**	**58,159,554**	**111,267,464**	**147,222,038**
Industry net income	**48,444,356**	**113,996,164**	**216,987,543**	**286,678,076**

The stakeholder's revenue share as a percent of the total is shown in Figures S.20 for the Major Gas Sales case.

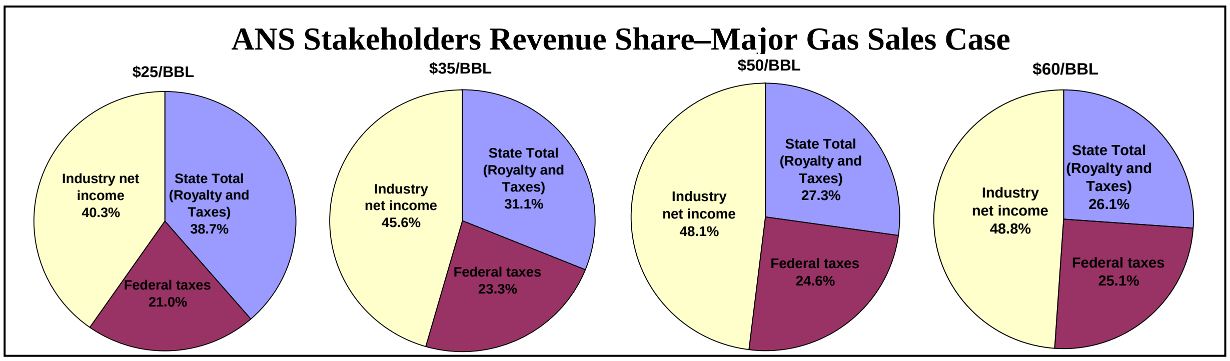

Figure S.20. ANS Stakeholder Revenue Shares–Major Gas Sales Case at ANS West Coast prices, 2005$.

Table S.18 shows the estimated incremental economic impact of major gas sales from PBU and PTU over the no major gas sales case. The sale of gas from PBU and PTU almost doubles the revenue stream received by the stakeholders and represents a significant new operating environment for the ANS.

Table S.18. Forecasts of incremental economic impact of Major Gas Sales: (PBU with gas sales–PBU w/o gas sales) plus PTU for ANS West Coast prices (then current $).

VARIABLE (M$)	**$25/bbl**	**$35/bbl**	**$50/bbl**	**$60/bbl**
State royalty	12,771,020	19,979,979	32,330,911	40,509,296
State taxes – Severance	8,427,365	13,839,883	22,252,154	27,860,341
State taxes – Income	1,703,365	3,076,855	5,040,806	6,355,283
State taxes – Other	443,589	432,816	433,354	433,354
State Total (Royalty and Taxes)	**23,345,339**	**37,329,533**	**60,057,225**	**75,158,274**
Federal taxes	**19,262,850**	**34,037,725**	**55,644,522**	**70,095,017**
Industry net income	**37,498,393**	**66,117,485**	**108,060,116**	**136,111,057**

S.5.8 Discounted Cash Flow Results

The economic analyses include the cumulative PW of the total cash flow (cum PW). A 10% discount rate is used for this assessment and is assumed to be representative of the current investment climate and the unrisked, real cost of capital. However, the 10% discount rate may not be representative of the discount rate that an individual operator or unit owner might use based on internal financial criteria. Therefore, sensitivities were run with discount rates at 15, 20, and 30% to examine project sensitivity to the discount rate. This analysis provides insight into the impact of discount rate to ANS project selection, field operations, development, and capital recovery. This analysis is presented below in Table S.19 for the $25/bbl case; similar results at the other price tracks are presented in the main report.

Table S.19. Pool Sensitivity to Discount Rate, $25/bbl.

Pool	cum PW @10%	cum PW @15%	cum PW 20%	cum PW 30%
Colville River, Alpine Oil	$1,738,979	$1,498,871	$1,316,468	$1,059,972
Endicott, Endicott Oil	($6,966)	($6,473)	($6,019)	($5,212)
Kuparuk River, Kuparuk River Oil	($25,360)	($28,700)	($27,054)	($20,488)
Kuparuk River, West Sak Oil	$4,281	$2,321	$1,071	($126)
Kuparuk River, Meltwater Oil	$113,751	$102,188	$92,638	$77,847
Kuparuk River, Tabasco Oil	$55,689	$49,551	$44,820	$37,937
Kuparuk River, Tarn Oil	$228,616	$208,029	$190,877	$164,009
Milne Point, Kuparuk River Oil	($3,206)	($4,074)	($4,756)	($5,718)
Milne Point, Schrader Bluff Oil	$13,553	$10,512	$8,134	$4,762
Milne Point, Schrader Bluff Oil, E - pad	($224,149)	($193,804)	($166,140)	($121,474)
Milne Point, Schrader Bluff Oil, S - pad	($239,175)	(223,122)	($230,418)	($214,885)
Milne Point, Schrader Bluff Oil, new pad	($246,986)	($188,063)	($144,199)	($86,913)
Northstar, Northstar Oil	$878,350	$761,447	$673,760	$551,407
Prudhoe Bay, Aurora Oil	$87,942	$79,728	$72,914	$62,312
Prudhoe Bay, Borealis Oil	$191,886	$175,697	$161,967	$140,041
Prudhoe Bay, Lisburne Oil	$11,111	$12,581	$13,469	$14,190
Prudhoe Bay, Niakuk Oil	$1,299	$1,683	$2,019	$2,551
Prudhoe Bay, Prudhoe Oil	$3,140,615	$2,602,595	$2,222,969	$1,730,041
Prudhoe Bay, Polaris	$53,743	$25,583	$7,175	($12,946)
Prudhoe Bay, Orion I, Schrader Bluff Oil	$59,837	$54,232	$49,630	$42,565
Prudhoe Bay, Midnight Sun Oil	$25,842	$23,991	$22,450	$20,010
Prudhoe Bay, Pt. McIntyre Oil	$249,032	$222,117	$200,380	$167,659
Kuparuk River, Placer Pool Oil	$73,401	$57,130	$45,409	$30,223
Kuparuk River, West Sak Additional (IE &IJ)	($153,526)	($118,629)	($94,406)	($64,537)
Colville River, Fiord	$103,559	$77,266	$58,562	$34,914
Colville River, Nanuq	$56,274	$40,269	$29,090	$15,379
Colville River, Alpine West	$65,974	$46,930	$33,892	$18,329
Colville River, Lookout	$75,349	$49,488	$33,152	$15,618
Colville River, Spark	$82,969	$54,436	$36,630	$17,666
Prudhoe Bay, Orion Phase II & III	($31,044)	($57,307)	($64,240)	($57,533)
Prudhoe Bay, Polaris Phase II & III	($33,509)	($54,388)	($60,831)	($56,809)
Oooguruk	($43,458)	($52,359)	($54,565)	($50,170)
Nikaitchuq	($558,614)	($496,944)	($441,633)	($350,089)

Pool	cum PW @10%	cum PW @15%	cum PW 20%	cum PW 30%
Liberty	$80,412	$39,201	$16,886	($1,393)
Gwydyr Bay	($138,073)	($122,201)	($107,312)	($82,177)
Sandpiper	$81,390	$27,815	$7,202	($2,669)
Sambuca	$47,500	$33,837	$24,695	$13,965
Tuvaaq	$166,892	$104,096	$66,670	$29,293
Ataruq	$12,331	$2,018	($3,496)	($7,464)
Sourdough	$48,574	$16,751	$4,011	($2,265)
Point Thomson - major gas sales	$1,302,388	$459,637	$146,181	($13,823)
TOTAL	**$7,347,473**	**$5,508,802**	**$4,178,052**	**$3,093,999**

This analysis shows that twelve pools are uneconomic at $25/bbl and a 10% discount rate. Three of the fields, Endicott, Kuparuk River, and MPU Kuparuk, are currently producing and are older producing fields. The remaining nine fields are the three MPU Schrader Bluff projects (new-, E-, and S-pad), Kuparuk River Additional pad, the two Prudhoe Bay projects (Orion Phase II & III, Polaris Phase II & III), Oooguruk, Nikiatchuq, and Gwydyr Bay. Additional fields become uneconomic as the discount rate is increased. At a $35/bbl price track only the MPU Schrader Bluff new pad project is uneconomic at a 10% discount rate. At the $50/bbl and $60/bbl price tracks all projects at 10%, 15%, 20%, and 30% discount rates are economic. Thus, the current oil price environment is sufficient to support additional development on the ANS. Actual project timing will depend on investment capital opportunities available elsewhere for an operator.

The additional analysis results at the higher oil price tracks are presented in the main report.

S.5.9 Minimum Economic Field Sizes (MEFS)

Minimum economic field sizes (MEFS) are estimated for each of the exploration regions described in Section S.4. These regions include the core region of the Central Alaska North Slope, NPRA, 1002 Area of ANWR, Beaufort Sea OCS, and Chukchi Sea OCS. A gas field MEFS is estimated for the gas prone southern portion of the Central Alaska North Slope, the Foothills area. The MEFS analysis considered both continued development of satellite accumulations and frontier exploration. The costs to explore, find, develop, produce and transport oil or gas at varying distances from existing infrastructure are analyzed to illustrate the impact of distance, infrastructure, and location. An additional analysis considers project timing on the MEFS to gauge the impact of project delays and cash flow structure on a project's economic viability. The estimates for MEFS (OOIP, OGIP) were determined at each of the four oil and gas prices tracks. The approach is described below.

S.5.9.1 MEFS Assumptions and Methodology

General assumptions and methodology used in the MEFS analysis are:

1. Two to four exploration wells will be required to find and delineate a discovery prior to investment and field development. Smaller accumulations will require two wells and larger ones will require four wells.

2. Exploration GG&E costs are assumed to include $50 million (2005$) for seismic, processing, geologic interpretation, geoscience activities supporting siting an exploration well, and the construction of ice roads for exploration drilling and project development. These costs are used in the Alaska Exploration Tax Credit calculation.
3. Exploration and development timing will vary across the region due to project availability, distance from infrastructure, land access, and other factors. The scenario chosen as the base case for exploration, development and first production across the ANS is presented in Table S.20. In the Central Arctic and Eastern NPRA, it is assumed for the MEFS comparison that development could occur rapidly after a discovery because of proximity to existing infrastructure. For the other regions, the 1002 Area of ANWR, Beaufort OCS, Chukchi OCS, and the Foothills gas case, first exploration, first development, and first production are timed to begin later as shown and longer times assumed before first production.

Table S.20. Assumed project timing by region.

Region	First Exploration	First Development	First production
Central Arctic–core area	2008	2009	2010
Eastern NPRA	2008	2009	2010
1002 ANWR	2010	2013	2015
Foothills Gas	2011	2014	2015
Beaufort Sea OCS	2010	2014	2015
Chukchi Sea OCS	2010	2014	2015

4. The number of development wells required is a function of field size. It is assumed larger fields will have higher production rate wells and average well recovery will increase with OOIP as shown in Figure S.21. Development drilling is assumed to occur over four years with 20%, 30%, 30%, and 20% of the total required number of development wells drilled each of four years. Half of the development wells are producers and the other half injection wells for oil reservoirs to support pressure maintenance and enhanced oil recovery; gas reservoirs utilize all production wells.

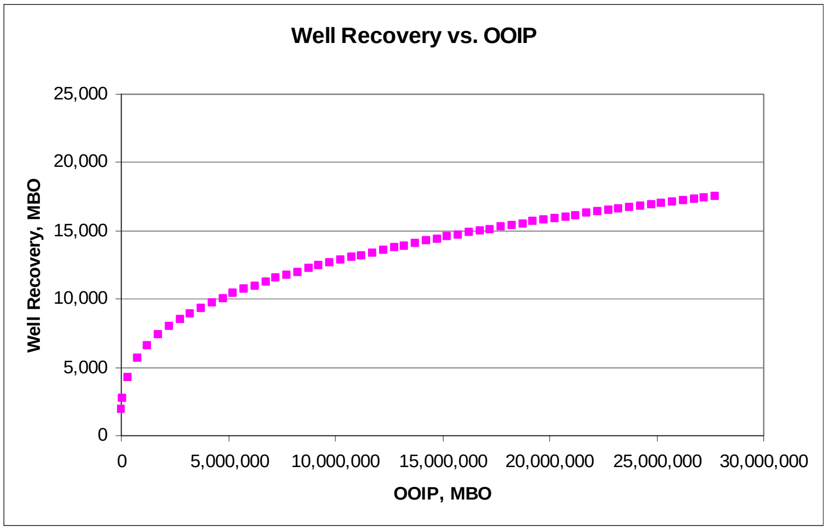

Figure S.21. Average well recovery as a function of OOIP.

5. Recoverable reserves use a 35% recovery factor for oil and 85% for dry gas reservoirs.
6. An algorithm is used to size the pipelines and field production facilities. Based on empirical evidence it is assumed that the peak rate is related to the accumulation size with a peak rate of 1 BOPD per 3,430 bbl of reserves. The production schedule is based on a percentage of the reserves as follows: year 1–3%, year 2–6%, year 3–9%, year 4–10.65%, year 5–10.65% and then follows a 15% nominal exponential decline.
7. The required pipeline size to deliver oil or gas to market is related to the peak flow rate calculated for the accumulation. For the range of flow rates considered, a throughput rate of 884 BOPD per square inch of cross-sectional area is used. This value is consistent across a wide range of pipeline sizes on the ANS. The gas pipeline sizing methodology is described in Appendix 3-E.
8. Pipeline capital costs to transport hydrocarbons to existing infrastructure are $20 per diameter-inch-foot (2005$) except for offshore Chukchi Sea, which uses $50 per diameter-inch-foot for the extreme arctic conditions offshore.
9. Oil operating costs use the cost structure described in Section S.5.5.2.
10. The discounted cash flow economic model is solved for the MEFS required for a cumulative PW = 0 at a 10% discount rate at the end of the project economic life. This analysis was conducted for each of the ANS West Coast price tracks.

Area-specific assumptions are described below.

Central Arctic core area: The MEFS analysis for the core area examined continuing satellite development at distances of five and ten miles from producing fields and support infrastructure. A number of smaller accumulations have been previously identified and processing facilities have unused capacity for new projects. The development assumptions are:

- Two exploration wells at $17 million (2005$) each.
- Development wells are $8.5 million each.
- Produced fluids are transported by feeder pipelines and processed at existing facilities for a facility sharing fee.
- Feeder pipeline costs are included in the investment costs.

NPRA: The MEFS analysis for NPRA examined exploration and development at distances of 50 and 100 miles west from the Alpine field along the Barrow Arch. Assumptions are as follows:

Scenario 1:

- Two exploration wells at $17 million each are required to discover and delineate an accumulation of sufficient size to support the installation of infrastructure remote from the Alpine field.
- Development wells are $8.5 million each.
- A stand-alone development will require a minimum 8-inch pipeline to the Alpine field pipeline and transport to PS-1 through existing pipelines.

Scenario 2:

- A 170-mile trunk pipeline with a minimum diameter of 24-inches from the field location 100 miles west of the Alpine field to PS-1. This analysis is predicated on a stand-alone project to determine the MEFS. The discovery a field of this magnitude can support the expansion of infrastructure into the NPRA along the pipeline corridor.

1002 Area of ANWR: The MEFS analysis for the 1002 Area of ANWR considered exploration and development at distances of 110 and 160 miles east from Pump Station 1. Assumptions are as follows:

- Three exploration wells at $17 million each.
- Development wells are $8.5 million each.
- A stand-alone development will require a minimum 8-inch pipeline for transport to PS1.
- The capital costs for a pipeline at a distance of 160 miles from PS-1 include $133 million for an intermediate pump station.

Alternatives for ANWR development could include a larger pipeline to accommodate the peak field production rate similar to the NPRA Scenario 2 described above or a pipeline to the existing Badami pipeline or to a Point Thomson development. These scenarios are not analyzed.

Beaufort Sea OCS: Offshore development opportunities are located in the relatively shallow portions of the Beaufort Sea shelf between Harrison Bay and the mouth of the Canning River. Discoveries are anticipated to occur within 5 to 25 miles offshore. Exploration will likely be offshore from the currently developed infrastructure, targeting structural plays and/or areas near the undeveloped Hammerhead and Kuvlum discoveries. Assumptions are as follows:

- Offshore field development 20 miles offshore using a gravel island or ice-resistant platform costing $300 million (2005$) and a sub-sea pipeline to shore and a 10-mile feeder line to a regional pipeline for transport through existing field pipelines to PS-1.
- Capital costs for four exploration and delineation wells are $25 million (2005$) each.
- Development wells are $20 million each.

Chukchi Sea OCS: The potentially large oil and gas accumulations in the Chukchi Sea represent especially promising exploration targets and potential development after 2015. Cost estimates for exploration and development wells, an offshore platform, production facilities, and a pipeline to shore are difficult to estimate for this frontier area with significant winter ice and arctic conditions. Assumptions are as follows:

- An offshore platform will be located 50 miles offshore and will cost $750 million (2005$).
- Exploration wells will require a drill ship and are assumed to cost $50 million (2005$) each for four exploration and delineation wells.
- Development wells are assumed to cost $20 million.
- A 50-mile subsea pipeline at a cost of $20 per diameter-inch-foot is used to transport the oil to shore and 50 miles of subsea gathering lines to collect and transport the oil to a central facility located on the platform. The cost for the offshore subsea arctic pipelines is assumed to be $50 per diameter-inch-foot.
- A 300-mi 24-inch diameter onshore pipeline from the western edge of the North Slope to PS-1 at a cost of $20 per diameter-inch-foot for a total cost of $760 million.

Development of infrastructure including roads and pipelines into western NPRA connecting developments the Central Arctic and to PS-1 could potentially reduce the Chukchi

Sea MEFS. This scenario was not analyzed due to the high level of uncertainly in such a scenario.

Central Arctic Foothills: The natural-gas-prone Foothills region could be a key production source for the AGP. The MEFS base case analysis assumed exploration would start in 2011 and require four exploration and delineation wells. Development drilling predicated on a discovery would start in 2014 with first gas production in 2015. Assumptions are as follows:

- Capital costs are estimated at $20 million and $10 million, respectively, for exploration and development wells due the remote area and absence of infrastructure.
- Pipeline costs are estimated at $20 per diameter-inch-foot for a minimum 24-inch pipeline at distances of 50 and 100 miles.
- Facilities costs are estimated at $37.5 per MMCFPD peak rate.
- Gas operating costs are based on a cost algorithm developed for Cook Inlet operations (DOE, 2004) and increased 1.5 times for ANS operations.
- It is assumed each development well will recover 75 BCF.

Table S.21 shows the OOIP or OGIP estimates equivalent to a cumulative PW = 0 at the last year of the project life at the economic limit using the project timing in Table S.20 for the four price tracks and the assumptions listed above.

Table S.21. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	Oil & NGLs (MB)	9,450	5,730	3,600	2,880
Core–10 miles	Oil & NGLs (MB)	11,950	7,241	4,547	3,644
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	402,300	84,160	33,220	23,350
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	894,100	147,700	63,530	44,340
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	1,918,000	610,800	278,100	205,400
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	1,684,000	195,900	82,930	58,830
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	3,335,000	560,600	209,500	151,000
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	1,322,000	1,019,800	249,900	165,500
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	15,562,000	3,393,000	983,500	614,600
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,181,000	458,800	232,700	173,300
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,166,000	837,100	431,200	328,200

The NPRA 100-mi. case with a pipeline to PS-1 and the ANWR 160-mi. case are similar distances from PS-1and have the same assumed cost structure; however, the ANWR case results in a significantly larger MEFS as a result of the five-year delay in project timing reflecting the impact of escalation on capital and operating costs.

The impact of project timing and delays on the MEFS is examined by two special cases: Case 1–All regions are analyzed for first exploration in 2008, first development in 2009, and first production in 2010. Case 2–All regions are analyzed for first exploration in 2010, first development in 2014, and first production in 2015. These results are shown in Table S.22 and Table S.23, respectively. The gray-shaded cells below indicate the base case start year for the projects.

Table S.22. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks, 2010 start of production.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	Oil & NGLs (MB)	9,450	5,730	3,600	2,880
Core–10 miles	Oil & NGLs (MB)	11,950	7,241	4,547	3,644
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	402,300	84,160	33,220	23,350
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	894,100	147,700	63,530	44,340
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	1,918,000	610,800	278,100	205,400
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	708,400	148,500	65,910	49,130
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	1,881,000	383,300	177,900	131,800
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	5,058,000	603,200	192,500	132,200
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	9,497,000	2,346,000	771,500	538,300
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,204,000	423,600	218,300	161,900
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,245,000	785,500	402,800	304,000

Table S.23. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks, 2015 start of production.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	Oil & NGLs (MB)	11,090	6,600	4,110	3,280
Core–10 miles	Oil & NGLs (MB)	13,710	8,144	5,060	4,038
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	1,458,000	140,100	53,270	35,430
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	2,304,000	222,200	87,430	61,980
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	2,983,000	796,500	339,000	242,100
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	1,684,000	195,900	82,930	58,830
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	3,335,000	560,600	209,500	151,000
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	1,322,000	1,019,800	249,900	165,500
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	15,562,000	3,393,000	983,500	614,600
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,181,000	458,800	232,700	173,300
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,166,000	837,100	431,200	328,200

These results demonstrate the significant price and time sensitivity for large frontier projects requiring large capital expenditures and long lead times, illustrating the combined effect of price risk and project delay on the MEFS. The larger frontier projects tend to have greater sensitivity and more pronounced increases in the required MEFS at the lower price tracks.

The above estimates of MEFS OOIP needed to be economic under these assumptions are subject to a large range of uncertainty. Another way to express the results is to use the USGS field class nomenclature (see Section 3.8.3), which has the advantage of expressing the MEFS in a broader range of field sizes and avoids expressing more certainty in the estimates than may be warranted. Additionally, this approach lends itself well to undiscovered resource distribution estimates. Table S.24 recasts the results in this fashion.

Table S.24. MEFS–USGS field class size for ANS West Coast Flat price tracks for the base case project start up.

MEFS Case	USGS Field Class Size			
	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	9	8	7	7
Core–10 miles	9	8	8	7
NPRA–50 mi. west of Alpine	14	12	11	10
NPRA–100 mi. west of Alpine	15	13	11	11
NPRA–100 mi. west of Alpine with pipeline to PS-1	16	15	14	13
ANWR–110 mi. east of PS-1	16	13	12	11
ANWR–160 mi. east of PS-1	17	15	13	13
Beaufort Sea–20 mi. offshore	16	15	13	13
Chukchi Sea–50 mi. offshore	19	17	15	15
Foothills gas–50 mi. to AGP	13	12	11	10
Foothills gas–100 mi. to AGP	14	13	12	11

These results show that the MEFS outside of the core area will require oil fields in Field Class Size of 12 to 17 (64 million to 4 billion) for the $35/bbl case and a Field Class Size of 11 to 15 (32 million to 1 billion) for the $50/bbl price track. Fields of this size are well within the expected range of field sizes. Fields larger than this will require longer lead times and are expected to be located in frontier regions.

S.7 Facility Sharing

Facility sharing is not a new concept on the ANS. Facility sharing has been used for many years, but to date, only within a unit boundary between an initial PA and unit satellites. With the discovery of smaller oil and gas accumulations that cannot support stand-alone facilities and to minimize the need to expand infrastructure where not essential, the possibility of processing their produced fluids in an existing facility is now actively discussed. This is becoming even more important and potentially more complicated by the involvement of independent operators new to the ANS. Issues relating to facility sharing and availability of capacity in pipelines were discussed in detail in a 2004 study (PRA, 2004). That study identifies factors and trade-offs that involved parties must resolve and agree on before a facility-sharing agreement is executed.

An example calculation was performed for the Liberty pool considering the impact with and without facility sharing. The Liberty pool is planned to be developed using the Duck Island Unit facilities to process the produced fluids.

The analysis shows that facility sharing reduces the required investment, with most of the investment occurring early in the life of the project. The avoided investment for the facility-sharing base case varies from $455 million for the low price track to $482 million for the higher prices. Table S.25 presents the cumulative PW of the total cash flow for the two cases and four prices tracks.

Table S.25. Cumulative present worth (discount rate equal 10%) comparison of the impact of facility sharing (thousands 2005$).

Scenario	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Cum PW with facility sharing	**($23,338)**	**$238,943**	**$665,296**	**$958,948**
Cum PW without facility sharing	**($102,672)**	**$165,787**	**$596,970**	**$890,540**
Δ Cum PW (facility sharing – without facility sharing)	$79,334	$73,156	$68,326	$68,408
Loss in reserves due to facility sharing, MBO	(11,456)	(7,410)	(1,622)	(538)

This economic benefit of facility sharing is greatest at the $25/bbl price track, even though either project is not economically viable at a $25/bbl price track. The estimated benefit of facility sharing for this example is an improvement of the Cum PW of $68 to $79 million; i.e., facility sharing results in a higher PW than stand alone facilities. However, facility sharing does result in the loss of reserves due to the additional operating cost from the facility sharing fees. Facility sharing is a trade-off between lower recoveries and avoided facility capital costs but where applicable, results in the conservation of capital and improved capital returns.

S.8 Summary – Engineering and Economic Analysis

The TRR's estimated for the current producing ANS fields total 4.7 BBO and the current estimated average recovery factor is 48%. For the known fields with pending or announced development plans, the TRR's total 1.3 BBO. For the known fields with near term development potential the TRR's total 388 MMBO. The total TRR for the field groups analyzed in the No-Major-Gas-Sales case is 6.4 BBO. For the Major Gas Sales case, condensate and oil from the PTU results in an additional 400 MMBO from PTU and an estimated decrease of 133 MMBO from PBU for a total from all categories of fields including PTU of about 6.7 BBO of remaining reserves. Development of these fields should sustain production rates near 900,000 BOPD until about 2015. Production is then expected to decline to about 300,000 BOPD by 2025 unless new discoveries are made and other known accumulations are developed. Very large discoveries will be required to increase production above 900,000 BOPD.

The total investment required by industry to achieve the forecast production is estimated at more than $14 billion dollars (then current dollars). This investment does not include the cost for construction of the AGP system. Total operating expenses are estimated at more than $59 to $85 billion (then current dollars) depending on the price track.

The TAPS minimum flow rate of about 300,000 BOPD, absent new developments or reserves growth beyond the forecasted TRR's, will be reached in 2025. If the AGP is built and gas sales from PTU and the associated oil and condensate sales would provide another boost to oil production and extend the life of TAPS for about one year to 2026. In either case, a TAPS shutdown would potentially strand up to about 1 BBO of oil reserves. The certainty of a gas pipeline is expected to increase exploration activity across the ANS areas and should result in new discoveries and infrastructure expansion resulting in additional oil and gas discoveries that extend the life of TAPS beyond 2050.

Other significant issues include the possibility of exploration in the 1002 Area of ANWR, which is likely to contain an estimated mean of 10.4 BBO in a 1.9 million acre area (5,475

BO/acre). The opening of the 1002 Area would be expected to significantly increase exploration activity and lead to increased oil and gas reserves.

The construction of an AGP by 2015 and the ability to sell gas from PBU and PTU will almost double the revenue to the stakeholders (state, federal, and industry).

The MEFS estimates and geological evidence for ANS areas indicate that oil and gas fields of sufficient size could be found to support development under anticipated oil and gas prices regimes, provided access to the areas and the fiscal and regulatory environment is supportive of the large investments that will be required. The MEFS analysis demonstrates the impact that project delays can have on the required field size to proceed with development. This problem is especially acute at the $25/bbl price track.

If all the ANS regions are open for development, including 1002 Area of ANWR, the prospects for continued development up to and beyond 2050 are excellent. However, if the assumptions of access to the most prospective areas across the ANS (onshore and offshore) and the possibility that an AGP will not be constructed in a timely manner do not happen, the ANS must be considered an area in decline and production could end by 2025 or soon thereafter.

A field developed with a facility-sharing agreement requires less capital investment than would be required for development as a stand-alone development with its own facilities and results in a similar project net present value. Hence, facility sharing has the potential to be a positive factor in future development.

S.9 Environmental and Regulatory Issues

The objectives of the "Environmental and Regulatory Issues" section are to (1) summarize the role of federal, state, and local government in the development of petroleum resources on the ANS and the associated regulatory basis for these roles; (2) briefly describe the key environmental issues involved with the development of these resources and identify any issues that could potentially prevent development in certain areas; and (3) describe how technology and practices employed on the ANS have changed over time resulting in a reduction in the size of the area impacted by development; i.e., the development footprint.

From the perspective of environmental permitting, development of petroleum resources on the ANS requires input from numerous local, state, and federal government agencies. In many cases, these agencies have regulatory authority over certain aspects of oil and gas exploration and development, while in other cases agencies serve in an advisory capacity. In recent years, petroleum resource development has expanded to lands administered by agencies of the federal government, resulting in the involvement of additional agencies such as the BLM. The legal authority for regulating exploration and development (E&P) of oil and gas resources on the ANS is found under various federal, state, and local laws, regulations, and ordinances.

Continued oil and gas development on the ANS and adjacent offshore areas must consider numerous environmental issues. The associated environmental impacts, however, can largely be ameliorated through the application of mitigative measures stipulated by the permitting process. The state of Alaska and BLM have developed a series of general mitigation measures to minimize impacts to air quality and water quality, and to reduce disturbance, mortality and habitat loss for wildlife species. Additional project-specific and site-specific mitigation measures may also be applied to particular E&P proposals as additional information becomes available. Despite these protective measures, some impacts may occur. A few environmental issues may be controversial enough to delay further development substantially, or to even prevent development of a particular field.

Over the history of active petroleum exploration and production on the ANS, dramatic changes have occurred both in terms of the technologies applied to petroleum development and the practices implemented during E&P. In general, the changes that have occurred in technologies and practices have had two goals: (1) to reduce E&P costs; and (2) to reduce the environmental impacts that may potentially result from E&P activities. In many cases, both of these goals were attained simultaneously, with new technologies or practices, or both resulting in a reduction in the environmental footprint from E&P activities while also decreasing E&P costs.

During the exploration phase of development, most of the important technological advances have focused on enabling industry to locate oil and gas deposits more accurately and to estimate the quantities of these resources more precisely, replacing older, less-efficient and often less environmentally friendly options. Advancements in technology, such as 3-D seismic have helped reduce the number of exploration wells drilled, thereby reducing exploration costs while simultaneously reducing the environmental impacts resulting from exploration. Use of ice for the construction of roads and pads during exploration has significantly reduced the environmental impacts associated with exploration. Increased reliance on remote sensing in the design and location of facilities, roads, and pads has also helped to reduce impacts to both terrestrial and aquatic habitats.

During the production phase, tremendous reductions in the overall footprint of development have also resulted from the use of horizontal and multilateral drilling technologies. These heavily computerized technologies have allowed for a greater number of wells to be drilled per pad, with closer well spacing on the pad, resulting in the need for fewer well pads. Much less habitat is disrupted by the construction of pads as fewer pads are required for a given surface area or volume of oil. This in turn results in reductions in the volume of water needed and in the volume of wastes generated. Other practices and technologies that are now being applied on the ANS include: (1) the use of rolligons to reduce damage to the tundra; (2) the use of less toxic drilling muds; (3) the elimination of reserve pits; (4) implementation of underground injection control programs; and (5) an increased reliance on enhanced oil recovery practices, which results in more oil produced from an individual accumulation without increasing the environmental footprint. The DOE micro-hole technology research program may result in reduction in hole size, which will also reduce the volume of drilling fluids and further reduce the environmental impacts.[25]

In a previous study, (Thomas, et al., 1991) three issues were identified that could conceivably prevent development from occurring in certain areas: (1) the no-net-loss policy for wetlands; (2) construction of solid-fill causeways; and (3) construction of pipelines connecting new fields to the TAPS. The wetlands issue has been resolved largely through a policy of

[25] http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Microhole2006_Mar.pdf

avoidance and minimization. Solid-fill causeways are no longer permitted in Alaska, but development of near-shore resources has continued because of advances in extended-reach drilling capability, which has allowed development of some of the near-shore fields from land, and under-sea pipelines. An under-sea pipeline was used for the first time on the ANS in the Northstar development. Pipeline concerns related to habitat protection have been largely resolved through the application of non-traditional technologies to protect key habitat such as boring under the river for river crossings to Alpine.

A number of potential "showstoppers" have been identified. Each of these issues has the *potential* for preventing development of a given field or set of fields. Some may be solved by further advances in technology, while others may ultimately prevent development in a given location. Key issues are as follows:

- **Land access:** Oil and gas resources cannot be developed if the industry does not have access to the land containing the resources. The primary example of this is the 1002 Area of ANWR, which remains closed to development. Related to this is the issue of critical habitat–the Endangered Species Act (ESA) requires that areas of critical habitat be protected, and some areas such as the Teshekpuk Lake area in the NPRA may remain off limits to development.
- **Dismantlement, Removal, and Restoration (DR&R):** A recent General Accounting Office study examined the current requirements and estimated costs associated with DR&R on the North Slope (GAO, 2002). This report concluded that current requirements for DR&R were very general, with little or no specific requirements regarding what infrastructure must ultimately be removed or to what condition lands used for resource development must be restored. The regulatory authority over DR&R requirements is complex and requirements are not well defined. Therefore, the costs associated with DR&R are unknown. If the policy of the federal or state government regarding DR&R becomes one of restoration to pristine conditions, development will be severely constrained.
- **Marine Mammal Protection:** The North Slope Borough and others have expressed concern over development of offshore resources and their potential impacts on bowhead whales, a species listed under the ESA. Concerns are voiced over other marine mammals from seismic exploration, drilling, and spills. Interpretation of the Marine Mammals Protection Act and other regulations will be required to ensure that exploration and development can be performed while affording protection to these species. Truncated seasonal operating times would likely increase offshore project costs and could make development uneconomic depending on field size and oil and gas prices.
- **Water Availability:** Although sources of fresh water for the construction of ice roads and ice pads are abundant in many areas of the ANS, as development progresses to the south and east of existing development, these sources of water become less frequent. Construction of ice roads and pads requires abundant water sources along the entire route – and these sources may not be available in areas such as the foothills. Established limits on water use may make development too costly in areas where water sources are limited.

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