REASONABLE FORSEEABLE DEVELOPMENT SCENARIO FOR OIL AND NATURAL GAS RESOURCES IN THE KOBUK-SEWARD PENINSULA PLANNING AREA, ALASKA

PREPARED BY

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List of Acronyms

ADNR	- Alaska Department of Natural Resources
AFO	- Anchorage Field Office
ASRC	- Arctic Slope Regional Corporation
Bcf	- Billion Cubic Feet
BLM	- Bureau of Land Management
CBNG	- Coalbed Natural Gas
CFR	- Code of Federal Regulations
DGGS	- Department of Geological and Geophysical Survey
DOE	- Department of Energy
DOT&PF	- Department of Transportation and Public Facilities
EIS	- Environmental Impact Statement
IRP	- Industrial Roads Program
KGRA	- Known Geothermal Resource Area
KSP	- Kobuk - Seward Peninsula
LMP	- Leasable Mineral Potential
Mcfpd	- Thousand cubic feet of gas per day
Mmcfpd	- Million cubic feet of gas per day
Mmb	- Million Barrels
MODPR	- Mineral Occurrence and Development Potential Report
NDO	- Northern District Office
NPRA	- National Petroleum Reserve in Alaska
RFD	- Reasonable Foreseeable Development
RMP	- Resource Management Plan
RTA	- Resource Transportation Analysis
Tcf	- Trillion Cubic Feet

I. SUMMARY

This Reasonably Foreseeable Development (RFD) scenario represents a hypothetical projection of oil and gas exploration, development, production and abandonment activity in the Kobuk-Seward Peninsula planning area (KSPPA). Estimating how much oil and gas activity will occur in the KSPPA during the life of the plan is difficult at best. Timing and location of future commercial-sized discoveries cannot be predicted until exploration of those reserves occurs. This scenario projects development on the assumption that all areas are open to development under standard lease terms and conditions except those areas closed by statute or for discretionary reasons. Separate estimates are given for seismic activity, drilling, and production activities. Coalbed natural gas (CBNG) is considered separately from conventional oil and gas.

The Kobuk-Seward Peninsula planning area encompasses approximately 13 million acres of BLM-administered lands in northwestern Alaska. Three petroleum basins fall entirely or partially within the Kobuk-Seward Peninsula planning area; the Colville Basin, Kotzebue/Hope Basin, and the Selawik Basin. These basins are considered prospectively valuable for oil and gas resources.

Of the eleven oil and gas plays identified by the USGS in the Northern Alaska Province, eight occupy the northern portion of the KSPPA. A play is a set of discovered or undiscovered oil and gas accumulations or prospects that exhibit nearly identical geological characteristics. These play areas serve as the focus for the projection of oil and gas development within the planning area. The U.S. Geological Survey has not conducted a coalbed natural gas play analysis within the planning area to date.

Under this baseline exploration and development scenario, about 6.3 million acres of the KSPPA would be made available for future leasing. Historical leasing patterns in the western Arctic Slope are used in this RFD to support the possible range and scale of activities associated with future lease sales in the planning area. It is assumed that 1.2 to 3.2 million acres would ultimately be leased, mostly in the northern portion of the planning area where plays have been identified. Using the 1.2 million acre figure, about 710,000 acres of BLM-administered lands would be leased in the KSPPA under this scenario.

It is assumed that seismic exploration within the KSPPA would range from 150 to 800 seismic (2-D) line-miles every four years over the life of the plan. This range is based on a four-year, 600 line-mile seismic exploration program that lead to the discovery of the Alpine field, and on historic seismic exploration in the NPR-A over a 28 year span from 1972 and 2000. In preparation for field development, it is assumed that a 130 square mile 3-D seismic survey would also be acquired during the winter months following the discovery. This is based on a similar program conducted after the discovery of the Alpine field.

Using the past 33 years of modern drilling activity in the western Arctic Slope to determine the average rate of wildcat drilling, approximately seven wells are drilled every five years. Given a planning period of 15 years, one would conclude that 21 exploration wells would be drilled in the planning area. Another possible development scenario, reflecting the higher end of projected exploration activity, assumes that the next 15 years would be similar to the most active 15-year period the western Arctic Slope has experienced. Again, using the past 33 years to base the analysis, the most active 15-year period for the planning area was from 1976 to 1991, with 33 wells drilled. Therefore, a reasonable exploratory drilling scenario for the planning area would range from 21 to 33 wells.

Using the 33 well scenario and the wildcat success ratio for frontier areas of 2.5 percent (or 1 in 40 wells), only one well is likely to have a sufficient show of hydrocarbons to be declared a discovery and to warrant the drilling of additional wells within the planning area. However, the success ratio for commercial fields on the North Slope has been about 5 percent (or 1 in 20 tested prospects is likely to be commercially developed). The discovery of commercial oil or gas would require year-round development and production activities. Field life is approximately 20 to 30 years, but larger fields may produce up to 50 years. Under this RFD scenario, the discovery field is estimated to produce for about 25 years. Based on the USGS play analysis of the Colville River Basin, both oil and gas may be found in the planning area. However, it is assumed that this field would be a commercial oil producer, as gas on the North Slope currently lacks a transportation system to market. The discovery of oil would initiate additional exploration efforts within the planning area and result in the drilling of 10 additional exploration wells.

Several delineation (confirmation) wells are likely to be drilled before a commitment is made to project development and another drilling season is utilized. To define the limits of the reservoir after the discovery, it is assumed 15 delineation wells would be drilled. Depending upon the depth of the potential reservoir and the size of the mapped prospect, these confirmation wells can be drilled from the same facility. In this scenario, the discovery is similar in size to the Alpine field, approximately 1 billion barrels of oil with gross recoverable reserves of 500 million barrels. Therefore, delineation wells averaging about 6 acres each would be drilled from additional drill sites.

It is assumed that the discovery field will comprise 40,000 acres and produce from 114 horizontal wells (roughly 57 injector wells and 57 producers) located on two drill sites, three miles apart. Gravel pads will be joined by a 35 foot wide, five foot thick gravel road that will also serve as an airstrip. Three to twelve inch diameter gathering lines will run from the remote pad to the main pad/central processing facility (CPF). One line will transport the crude oil and a parallel set of lines will transport the gas and water from the CPF to the remote pad for fuel, injection, or disposal. These lines will be elevated on steel vertical support members. An industrial-sized, all-weather airstrip would be built and measure150 to 200 feet wide and 5,000 feet long, with potential to cover 20 to 30 acres. It would require approximately 140,000 to 200,000 cubic yards of gravel. The volume of gravel varies significantly, because the amount required depends upon the nature of the substrate. Permafrost and extensive poor drainage would pose problems to any construction on tundra. Consequently, a gravel airstrip would need to be 5 feet thick. Gravel required for construction will most likely be mined during the winter months to reduce impacts and be located as close to the field as feasible using two or three separate deposits, 20 to 50 acres in size, to minimize environmental impacts.

Surface impact (gravel footprint) will comprise about 100 acres and would require about 1,000,000 cubic yards of gravel. The main pad would also serve as a stand-alone production facility and would not be connected by a permanent gravel road to existing infrastructure on the North Slope. Staging areas for field development would be built during the winter months prior to development activities and may require up to 150 acres each. Drilling supplies and major equipment will be transported in winter using ice roads. Food and personnel will be transported by air to an adjoining 5,000 foot gravel airstrip. The permanent production operation would consist of a remote drill pad, connecting gravel road and parallel pipeline, main pad/central processing facility (CPF) and a production pipeline to transport the oil to market.

An oil or gas discovery has to get its product to market. Pipelines are the most efficient means of transportation across remote and undeveloped areas. It is assumed an elevated (7 feet off the ground) 24 inch diameter production pipeline would be sufficient to carry the estimated 80,000 to 100,000 barrels of oil per day (BOPD) from the field. It is designed to transport more oil with the addition of pumps.

It is assumed that four additional discoveries would be made, over the life of the plan and that these would result in the development of satellite fields, each 10 acres in area. These developments would be located within 25 miles of the main pad/CPF with construction occurring one at a time, but within the life of the plan. The discovery of each satellite field is assumed to require three exploration wells and two delineation wells, and contain 10 production wells and 7 injection wells. Each field would have a production life of 10 years. No permanent camp facilities would be required for development of the satellite fields. The main pad/CPF would be upgraded to accommodate the increase in workers necessary to operate the additional satellites. However, temporary camps would be used during construction.

Coalbed natural gas (CBNG) exploration in the KSPPA would likely occur through an ongoing joint State/Federal program to assess the coal bed natural gas resource potential of Alaska. The program will also determine the feasibility of developing this resource for the benefit of rural communities in the state.

A small coalbed gas field in a remote area, sub-commercial by industry standards, could represent a viable, long-term energy resource for a small village or major mine site such as the Red Dog zinc mine. The costs of exploration, development and production of coalbed gas must compare favorably to the existing cost of supporting the current diesel fuel-based system. Proximity of the gas to rural customers is also a critical component.

It is assumed under this scenario that a discovery is made in the Kukpowruk coal basin near the village of Point Lay (pop 250) in the northwest section of the KSPPA. The economic viability, however, of the Kukpowruk coal basin's CBNG resources is highly uncertain because sufficient data on gas and water productivity does not yet exist. Under this RFD scenario for coalbed natural gas production through 2020, recoverable reserves are assumed to be 0.5 billion cubic feet (Bcf) and accessible from multiple coal seams. This would supply a population of about 250 with sufficient gas for 30 years. This development scenario would require a total of 12 wells; 10 producing wells, 1 monitoring well and 1 water reinjection well.

Typical CBNG wells require a network of access roads, drilling sites, pipelines, power lines, compressor stations, and containment ponds. Roads and utility corridors would be positioned to use existing disturbances as much as possible. Existing roads would be used as often as possible, and the gas field would be designed so that as many wells as possible can be serviced from each road. Roads to wells and compressor sites would be limited to single lane width with turnouts. Exploration wells would not have permanent gravel access roads. The operator would co-locate electric power, gas and water lines with proposed roads when feasible to minimize overall disturbance. Power lines would be aboveground or buried per operator's plans. Under this scenario, it is assumed that the field is located close to an existing fuel distribution point near the village and much of the disturbance associated with a commercial venture would no be realized.

Wells would be drilled with truck mounted water well type rigs capable of setting up on uneven terrain. Air is used to drill and remove the cuttings, instead of fluid, to reduce the volume of wastes to be buried on the well pad or hauled off site. A 100' square area would be bladed to accommodate the rig and a small reserve pit (6' x 15' x 15'). Each pad would require about 1.75 acres; 1 acre for the pad (190' by 240') and 0.75 acres for the access road. Part of the well pad area would be reclaimed for production operations and the entire area would be reclaimed when the well is plugged and abandoned.

Once all wells have been drilled, produced water would be gathered and transported to the injection well for disposal. Wells determined to be productive would be shut-in until a production facility is constructed. If the well is determined not to be productive, it will be properly abandoned.

The average well discharge rate for a typical coalbed natural gas well is about 400 to 500 barrels of water per day. It is assumed the amount of water produced would not be the same for every well, and that water production would drop off rapidly over time, as the pressure within the coal seam falls and gas begins to flow freely. The early phases of high water production and low gas recovery would last for a period of six months to three years. The produced water would be collected in a buried two-inch polyethylene flowline for transport to the water disposal well (200' x 200' each). The pipeline trenches for well gathering lines are expected to disturb portions of 20 to 30-foot wide corridors temporarily and to be reclaimed as soon as practical after construction is completed. Trenches would be constructed along the access roads where possible. Separate gathering lines would be buried in the trenches and would transport methane gas to a production facility and produced water to disposal well.

The water disposal well pad would consist of one 100 bbl water tank, a pump house, piping, and a well house. Those areas where elevation differences require supplemental pumping to transfer the produced water, transfer pumping stations (120’ by 120’ pads), consisting of a 100 bbl water tank with associated pump and piping, may also be needed. Water in the tank would be separated from the gas and injected into subsurface aquifers geologically isolated from potential underground sources of drinking water. Disposal rates would be dependant on formation characteristics of the injection zones and in this scenario it is assumed that one injection well would service the 12 CBNG wells.

Unlike conventional natural gas, CBNG has not generally required special treatment before sale - the gas is merely put through a dehydrator to remove remaining water and then injected into a pipeline. However, any impurities would be removed before the gas is sent the production facility.

Produced natural gas (methane) under wellhead pressure would move through the low pressure gas gathering system to a field compressor station (0.5 acres). Under this RFD scenario the gas gathering system would consist of 1 pod station designed to raise the pressure from about 30 psi to 150 psi. A one mile gathering line (approximately 25 feet wide), consisting of polyethylene flowlines (one per well) would be buried from each pad to the field compressor. These lines would be laid in the travel routes to the wells and would follow the road to the field compressor. The gas from each well is metered in the pod station and commingled prior to being piped a distribution point near the village.

II. INTRODUCTION

A “Reasonably Foreseeable Development Scenario” (RFD) represents the most likely projection (scenario) of oil and gas exploration, development, production, and abandonment activity. The RFD covers oil and gas activity in a defined area for a specified period of time. This RFD projects a hypothetical baseline scenario of activity assuming all potentially productive areas can be open under standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation or executive order. The baseline RFD scenario provides the mechanism to analyze the effects that discretionary management decisions have on oil and gas activity. The RFD also provides basic information that is analyzed in the National Environmental Policy Act (NEPA) document under various alternatives (USDOI-BLM IM No. 2004-089).

Impacts caused by the extraction of resources for energy purposes cannot be assessed without estimating future activity. Estimates of these future activities will address current crude oil and natural gas prices, anticipated crude oil and natural gas prices, oil and gas occurrence potential, new oil and gas plays, as well as renewed interest in existing plays, leasing, seismic survey results, drilling, and production. It should be noted that the accuracy of the estimate will likely decrease in regard to time.

III. DESCRIPTION OF GEOLOGY

The Kobuk-Seward Peninsula planning area encompasses approximately 13 million acres of BLM-administered lands in northwestern Alaska. The planning area extends roughly from Norton Sound in the south to Icy Cape in the north and from the Seward Peninsula in the west to the Nulato Hills and Gates of Arctic NWR in the east .

Three petroleum basins fall entirely or partially within the Kobuk-Seward Peninsula planning area; the Colville Basin, Kotzebue/Hope Basin, and the Selawik Basin (Ehm, 1983). These basins are considered prospectively valuable for oil and gas resources. The analysis of hydrocarbon-resource occurrence and development potential within the KSPPA is focused in and around these basin boundaries. A more complete description of geology for the entire KSPPA can be found in the Mineral Occurrence Potential Report (Appendix 1).

A. COLVILLE BASIN

The Colville Basin is one of two basins in Alaska where hydrocarbons are currently being produced. Hydrocarbon generation in the Colville Basin commonly correlates with deposition of the Cretaceous-Tertiary Brookian sequence. It was driven eastward by progradation of the Brookian shelf margin along the basin axis. Accordingly, a hydrocarbon generation “front” was initiated in the southwest of the NPRA (within the KSPPA) during the Albian, migrated across the NPRA during the Albian and Cenomanian, and progressed through the state lands from the Cenomanian to the Eocene (Burns and others, 2003).

1. Oil and Gas Play Overview

Within the planning area, four confirmed plays and four hypothetical plays have been identified in the Colville Basin by the USGS. A play is a set of discovered or undiscovered oil and gas accumulations or prospects that exhibit nearly identical geological characteristics. The confirmed plays are Topset, Turbidite, Ellesmerian-Beaufortian Clastics, and the Fold Belt. The hypothetical plays include; Lisburne, Lisburne Unconformity, Endicott, and Western Thrust Belt (Magoon and others, 1996). These plays are further subdivided into more specific detail in NPRA where extensive studies have taken place. For the purposes of this report, the eight plays described by the USGS in their 1995 assessment will be used.

Topset Play (excerpt from Magoon and others, 1996)

This conventional oil and gas play consists of stratigraphic and structural (fault) traps in sedimentary reservoirs of Cretaceous and Tertiary age. It includes those rocks represented on seismic records in the topset position of a clinoform sequence. The rocks consist of marine and nonmarine deltaic sandstone, siltstone, shale, conglomerate, and coal assigned to the Lower, Middle and Upper Brookian sequences encompassing the Nanushuk Group and Sagavanirktok Formations and the uppermost parts of the Torok and Canning Formations. The play is limited to the area of relatively flat-lying strata north of the fold and thrust belt that generally corresponds to the Coastal Plain Physiographic Province.

Potential reservoir rocks consist of sandstone and conglomerate. Stacked shoreline sandstones may be present in areas where basin subsidence equaled sedimentation for prolonged periods of time. Fair to good reservoir continuity is expected parallel to depositional strike (northwesterly). Porosity is approximately 10 to 20 percent in the western part of the play.

Within the play interval, deltaic shales and mudstones are thermally immature and probably gas-prone. Directly beneath the play interval, marine foreset and bottomset shales (Torok and Canning Formations) are poor to fair oil source rocks that are immature to marginally mature in the play area. Deeper in the section, rich oil source rocks of the Hue Shale, an underlying informally designated pebble-shale unit, the Kingak Shale, and the Shublik Formation are mature beneath most of the play area. Source rocks reached maturity in the Late Cretaceous in the western part of the play. Maturity occurred as a result of burial by rocks of this play. Migration pathways have been noted along faults and along clinoform bedding.

Assumed traps are mostly stratigraphic and are related to facies changes or by cut and fill features; structural traps are formed by small-displacement normal faults. The faults and interbedded shales are expected to provide only fair to poor seals, therefore hydrocarbon accumulations will probably consist of oil rather than gas. A total of 250 exploratory wells have penetrated this play, however, all are located east of the planning area. Oil accumulations have been discovered at Fish Creek, Cape Simpson, Milne Point, and West Sak. The potential for undiscovered oil and gas resources greater than the minimum size used in this assessment is considered good. Potential increases from west to east.

Turbidite Play (excerpt from Magoon and others, 1996)

This play consists of stratigraphically trapped deep-marine sandstone reservoirs of Cretaceous and Tertiary age and includes those rocks represented by the foreset and bottomset seismic reflectors in the clinoform sequence north of the fold and thrust belt. The play includes Lower, Middle, and Upper Brookian turbidites assigned to the Torok and Canning Formations. Rock types in this play are predominantly marine shale and siltstone with minor amounts of sandstone.

Reservoir rocks may occur anywhere within the play interval, but they are most frequently encountered in the lower half of the play interval as toe-of-slope or basin-plain turbidites. Individual sandstone bodies are expected to be thin and laterally discontinuous; aggregate reservoir thickness may occasionally reach 100 feet or more. Reservoir porosity varies from 5 to 30 percent.

Source rocks include the marine shale of the Torok and Canning Formations, which are expected to be relatively gas-prone. The Hue Shale is the richest oil-prone source rock known in the play interval and lies directly beneath the turbidites. Other oil-prone source rocks beneath this play include the pebble shale unit, the Kingak Shale, and the Shublik Formation.

The turbidite reservoir sandstones in this play are the deep-water equivalents of the deltaic deposits of the overlying Topset play. Thus thermal maturation of the source rocks was the result of burial by rocks of this and the overlying play. The timing relative to stratigraphic-trap formation is judged to be ideal, and migration distances relatively short because some turbidites rest directly on the Hue Shale.

Assumed traps are stratigraphic and are related to facies changes, or they are traps formed against small-displacement normal faults. Faults and the surrounding thick marine shales are expected to provide fair to good seals.

More than 200 exploratory wells and 2,000 development wells have penetrated this play; but relatively few have been targeted for deposits within the play. Four oil accumulations have been discovered (Flaxman Island, Badami, Stump Island pool of Point McIntyre field, and Colville Delta). Sizes of these accumulations have not been reported. Oil has been recovered from turbidite reservoirs in numerous exploratory wells in the play. Prospects for additional discoveries are speculated to be excellent.

Ellesmerian-Beaufortian Clastics Play (excerpt from Magoon and others, 1996)

This confirmed conventional oil and gas play consists of combined stratigraphic and structural traps of sandstone reservoirs in the gently south-dipping Permian to Early Cretaceous section, above the Lisburne Group. The play interval consists mostly of siltstone and shale with as much as 10-percent sandstone. The northern boundary of the play is the southern boundary of the Barrow Arch Ellesmerian and Barrow Arch Beaufortian plays, where the play interval may be as thin as 400 feet. The southern play boundary lies beneath the Foothills Physiographic Province, where the play interval rocks become involved in Brooks Range compressional structures.

Potential reservoirs include sandstone in the Echooka and Ivishak Formations, the Sag River Sandstone, several unnamed sandstone units in the Kingak Shale, Kuparuk Formation, and stratigraphic equivalents of the Kemik Sandstone. These sandstones were deposited primarily in shallow-marine environments. Porosities may reach 25 percent in the northern parts of the play area, but are anticipated to decrease to less than 10 percent in the southern parts. Most reservoirs, particularly those with the best porosity, are expected to occur beneath the Coastal Plain Physiographic Province.

The play interval contains many of the richest source rocks on the North Slope, including the Kavik Shale, the Shublik Formation, the Kingak Shale, the pebble shale unit, and the Hue Shale. These shales range from marginally thermally mature in the northernmost parts of the play to overmature in the southern parts. Basin reconstructions and burial-history calculations show that source rocks reached maturity as a result of burial by Cretaceous and Tertiary foreland basin fill. Maturity was achieved in the Late Cretaceous in the western part of the play and the early to middle Tertiary in the easternmost part. The migration direction would have been generally northward. Oil and gas accumulations are expected to be trapped in stratigraphic or a combination of fault and stratigraphic traps. Shales within the play interval are expected to provide adequate seals.

Exploration status: The Walakpa gas field was discovered in 1977 during the NPRA program. Although the size of the field is undetermined, an estimate of 60 Bcf is probable and an upper size limit of 1 - 4 Tcf of gas is possible if the reservoir is widely distributed. Oil and gas shows are reported in several wells in this play; good gas shows have been encountered in the South Simpson and Tunalik wells. A few dozen exploratory wells have penetrated this play, a few of which were drilled for prospects in the play interval.

The potential for undiscovered oil and gas resources greater than the minimum size used in this assessment is considered good.

Lisburne Play (excerpt from Magoon and others, 1996)

This hypothetical play consists of structurally and stratigraphically trapped carbonate or clastic reservoirs in the gently south-dipping Lisburne Group. The northern play boundary is the Lisburne onlap limit west of long 154° W. The Lisburne Play extends southward to the area beneath the northern Brooks Range at depths greater than 26,000 feet. Only autochthonous (originating where found) Lisburne rocks are included in this play. The play-interval thickness may vary from zero at the onlap edge to as much as 4,000 feet in areas such as the Ikpikpuk-Umiat Basin. Total area of the play is about 57,000 sq mi.

Potential reservoir rocks include dolomite, limestone, and sandstone. Dolomite, the most important reservoir with porosity occasionally as high as 25 percent, is expected to occur most abundantly in the late Mississippian part of the Lisburne Group. Dolomite of this age is not expected in the northernmost or western part of the NPRA because Lisburne rocks of this age are missing by onlap. Limestone porosity in the Lisburne is expected to average less than 5 percent. Sandstone, which may be common along the northern onlap edge in the NPRA, may be partially to completely cemented with calcite and, thus, may serve as a marginal reservoir. Depth to the top of the Lisburne in the play ranges from 10,000 feet along the northern play boundary to greater than 26,000 feet in the south.

Potential source rocks include marine shale in the overlying Sadlerochit Group, marine shale and limestone within the Lisburne, and marine to lacustrine shale and coal in the underlying Endicott Group. Where truncated by the regional Lower Cretaceous unconformity at the easternmost part of the play, the pebble shale unit and the Hue Shale overlying the unconformity may be important source rocks. Limited geochemical data suggest that all except the pebble shale unit and Hue Shale are fair to poor, gas-prone source rocks that are thermally mature in the northern part of the play and supermature in the southern part. Oil residue is often encountered in porous dolomite in the Lisburne Group, and hydrogen sulfide gas was encountered in interbedded limestone and shale near the Lisburne-Endicott

Group boundary at a depth of about 17,500 feet in the Inigok-1 well. In western Alaska, burial-history analysis indicates that hydrocarbons may have been generated in Early Cretaceous burial by the Colville Basin fill. Because the reservoir traps formed relatively early, the postulated timing of thermal maturity and migration for this play are regarded as favorable. In general, maturation would have occurred earlier in the southern and western parts of the play and the migration direction would have been from south to north.

Stratigraphic traps related to the Lisburne Group onlap edge and facies changes are expected in the northern part of the play area. Numerous low-relief (<200 feet) structural traps, noses, and faults are seismically mapped in the NPRA, apparently the result of folding and faulting during Mississippian, Pennsylvanian, and Permian(?) time. In the northwestern part of the NPRA, numerous seismic anomalies have been mapped; these may be carbonate buildups (reefs) and may constitute yet another potential trap type. Sealing rocks are expected to be interbedded shale and impermeable limestone.

Less than a dozen exploratory wells have been drilled for prospects in this play; no hydrocarbon accumulations are known. Available data suggests limited resource potential, probably all natural gas. Because of the relatively few wells and large area covered by this play, there are many geologic uncertainties. Chief among these are distribution, continuity, and thickness of reservoirs, size and integrity of traps (adequacy of seals), and the richness of source rocks.

Lisburne Unconformity Play (excerpt from Magoon and others, 1996)

The Lisburne Unconformity Play consists of stratigraphic traps developed as a result of differential erosion on the regional Permian or Lower Cretaceous unconformities that lie at the top of the Lisburne Group. The play is hypothetical because the amount of differential erosion on the unconformities is largely unknown and the coincidence of relief with porous carbonate rocks is also unknown. The play encompasses the entire area of Lisburne Group beneath the Permian and Lower Cretaceous Unconformities, including that area overlying the Barrow Arch. The southern limit of the play coincides with the southern limit of the Lisburne Play. Total area of the play is about 60,3500 sq mi.

Reservoir rocks are expected to be porous dolomite and limestone, similar to that in the Lisburne Play. Depth to the Permian unconformity in the play area ranges from about 8,000 feet to greater than 26,000 feet.

Potential source rocks are mostly gas-prone marine and nonmarine shale. Oil-prone source rocks younger than the Lisburne Group may be in fault contact with Lisburne rocks along the Barrow Arch. Timing and migration are considered good because the traps would have formed early. Postulated traps are envisioned to consist of erosional scarps and remnants of porous Lisburne Group carbonates sealed by the overlying Sadlerochit Group. These traps are analogous to those that trap most Mississippian oil and gas accumulations beneath the plains of Alberta.

As many as 50 exploratory wells may have penetrated this play, but few, if any, were drilled for prospects. Because of the small probability for traps and favorable reservoir, the chance for hydrocarbon accumulations greater than the minimum size used in this assessment is considered remote.

Endicott Play (excerpt from Magoon and others, 1996)

This hypothetical play consists of combined structural and stratigraphic traps in sandstone reservoirs in the Mississippian Kekiktuk Conglomerate, and sandstone or dolomite reservoirs in the overlying Kayak Shale, both formations belong to the Endicott Group). The northern boundary of the play west of long 155° W. is the onlap edge of the Endicott Group; east of this longitude, it is the southern boundary of the Barrow Arch Ellesmerian Play. The Endicott Play extends southward to the area beneath the northern Brooks Range at depths greater than 24,000 feet. Only autochthonous rocks, those not involved in Brooks Range deformation, are included in this play. Thickness of the Endicott Group is generally 100 - 1,000 feet but locally may be as much as 10,000 feet. Total area of the play is about 57,500 square miles.

Potential reservoir rocks consist primarily of fluvial to shallow-marine(?) quartzose sandstone and conglomerate within the Kekiktuk Conglomerate. Minor amounts of shallow-marine dolomite and sandstone are present in the overlying Kayak Shale. Porosity is expected to be less than 10 percent because of extreme burial depths; about 90-percent of the play lies at depths greater than 12,000 feet. and half of the play at depths greater than 24,000 feet.

Potential source rocks include coal and lacustrine shale in the Kekiktuk and marine shale in the Kayak. Limited geochemical data suggest that all are poor to fair, gas-prone source rocks that are thermally mature in the northern part of the play and supermature in the southern part. R_o values of 2.0 percent generally coincide with the -12,000 ft structure contour. Hydrogen sulfide gas was encountered in interbedded limestone and shale near the Lisburne-Endicott Group boundary at a depth of about 17,500 feet in the Inigok-1 well.

Burial-history analysis indicates that hydrocarbons may have been generated as early as Permian time in the Ikpikpuk-Umiat basin; elsewhere, generation did not occur until Early Cretaceous burial by Colville basin fill. Because the reservoir traps formed relatively early, the proposed timing of thermal maturity and migration for this play is regarded as favorable. In general, maturation would have occurred earlier in the southern and western parts of the play and the migration direction would have been from south to north.

Traps are expected to be structural folds and faults that were developed during the formation of Endicott Group basins in Mississippian, Pennsylvanian, and Permian(?) time. Numerous low-relief (<200 feet) structural traps, noses, and faults are seismically mapped in the NPRA at the Lisburne Group level, apparently the result of folding and faulting during Mississippian, Pennsylvanian, and Permian(?).

Interbedded Kekiktuk Conglomerate shale and the overlying Kayak Shale are probable seal rocks.
Exploration status: Less than a dozen exploratory wells have been drilled for prospects in this play; no hydrocarbon accumulations are known.

Available data suggests limited resource potential, probably all natural gas. Because of the relatively few wells and large area covered by this play, there are many geologic uncertainties. Chief among these are: 1) distribution, continuity, and thickness of reservoirs,, 2) size and integrity of traps (adequacy of seals), and 3) richness of source rocks.

Fold Belt Play (excerpt from Magoon and others, 1996)

This confirmed conventional oil and gas play consists primarily of anticlinal traps in Cretaceous and Tertiary sandstone reservoirs in the northern part of the Brooks Range fold and thrust belt. The Fold Belt Play is situated north of the Western Thrust Belt Play and south of the Topset Play; its western border is the offshore national 3-mile territorial limit in the Chukchi Sea, and its eastern border the same offshore limit in the Beaufort Sea. The Fold Belt play encompasses the Nanushuk Group; the Torok, Sagavanirktok, and Canning Formations; the Hue Shale, the pebble shale unit, and the Kemik-equivalent sandstones. Even older strata may be included in the play along its southern border.

Potential reservoirs are sandstones representing deltaic, shallow-marine, and turbidite environments. Porosity is expected to range from 5 to 30 percent and to improve eastward across the play. Drilling depths range from the near-surface to greater than 20,000 feet. Potential source rocks include generally gas-prone shales of the Nanushuk Group and the Sagavanirktok, Torok and Canning Formations and the underlying more oil-prone shales of the Hue Shale, pebble shale unit, Kingak Shale, and Shublik Formation. Gas-prone source rocks within this play range from thermally immature to mature, whereas most oil-prone source rocks range from mature to overmature. The eastern part of the play is considered more oil prospective than the western part because of greater thicknesses of the oil-prone Hue Shale in the east. Oil seeps and oil-stained sandstones are numerous.

Hydrocarbon migration would initially have been controlled by depositional geometries (such as clinoforms and onlap relations). Migration directions along clinoforms would have been generally southwestward. Hydrocarbons that were trapped during this time may have re-migrated into anticlinal traps following deformation. The time lag between maturation and structural deformation is not known. Traps are faulted anticlines related to Brooks Range deformation. In addition, all of the stratigraphic trapping possibilities in the Topset, Turbidite, and Ellesmerian-Beaufortian Clastics Plays should also exist within this play. Shales within the play are expected to provide fair to good seals, although their effectiveness may be reduced by faulting and related fracturing.

Both oil and gas seeps are known in the play and six non-economic accumulations have been discovered: Umiat oil field, Gubik gas field, East Umiat gas field, Wolf

Creek gas field, Square Lake gas field, and Meade gas field. Approximately 50 exploratory and delineation wells have tested 30 structures in this play. The number of untested structures may be more than 100. The potential for undiscovered oil and gas resources greater than the minimum size used in this assessment is considered good.

Western Thrust Belt Play (excerpt from Magoon and others, 1996)

This hypothetical conventional oil and gas play consists primarily of structural traps in Mississippian and Pennsylvanian carbonate reservoirs in the Brooks Range fold-and thrust belt. The northern boundary of the play, guided by seismic reflection data within the NPRA, is drawn far enough north to encompass all of the estimated occurrences of thrust sheets of Lisburne Group carbonates. The southern boundary is arbitrarily placed about 30 mi into the Brooks Range; the area farther south is expected to have negligible petroleum potential based on the observed southward increase in the level of thermal maturity. The western play boundary is the offshore national 3-mile territorial limit in the Chukchi Sea. Greatest potential for petroleum in the Western Thrust Belt Play is expected to be along the immediate range front and foothills to the north. The thickness of rocks in the play may exceed 35,000 feet. The total area of the play is about 16,000 square miles.

Lisburne Group carbonate rocks are the primary reservoir rock in the play. Other potential reservoir rocks include graywacke sandstone of Jurassic and Cretaceous age and fractured chert and siliceous shale of Mississippian to Jurassic age. The structural style of potential prospects and physical nature of potential reservoir rocks is exemplified by the Lisburne #1 well, which encountered five, 1,200 foot thrust repetitions of the Lisburne Group. Drilling depths range from near-surface to greater than 35,000 feet. Potential source rocks include marine shale of Mississippian to Cretaceous age. Oil shales of Mississippian, Triassic, and Jurassic ages are known to occur within this play, but they are considered representative of local occurrences and not characteristic of the entire play. Preliminary data from the Lisburne-1 well indicate that Jurassic-Triassic rocks are fair to good oil source rocks. Most source rocks are expected to be thermally mature to overmature, although the data are sparse and the geologic relationships complex. The western part of the play displays higher maturity than the eastern part. Bitumen in pores and fractures was encountered in the Lisburne-1 well along with minor indications of gas. Veins of bitumen are known from outcrop localities.

Analysis of paleothermal indicators in the Lisburne #1 well and in the western Brooks Range suggests that thermal maturity results from tectonic burial. A favorable aspect of this situation is that hydrocarbon migration would have been directly into early-formed structural traps. An unfavorable aspect is the duration of deformation, which lasted from Early Cretaceous to early Tertiary time and may have been episodic or quasi-continuous, thus compromising trap integrity.

Traps in the play are large anticlinal structures composed of multiple thrust sheets of carbonate rocks. Shales within the play are expected to provide fair to good seals, although their effectiveness may be reduced by faulting and related fracturing. Only four exploratory wells have been drilled in this play. Large, untested structures remaining in the play may number in the dozens. The potential for undiscovered oil and gas resources greater than the minimum size used in this assessment is considered fair.

B. KOTZEBUE/HOPE BASIN

The Kotzebue/Hope Basin is primarily an offshore Tertiary basin (Elswick, 2003). It extends approximately 430 miles from the Kobuk River delta, west along the coast of the Seward Peninsula to Ikpek Lagoon, then northwest across the Bering Strait to northeastern Russia. The origin of the basin has been attributed to transtensional deformation associated with the left-lateral Kobuk fault (Tolson, 1987) with a series of NW-SE and E-W trending faults that primarily dip to the southwest (Elswick, 2003).

1. Oil and Gas Play Overview

The Minerals Management Service (MMS) has defined four conceptual plays associated with the Kotzebue/Hope Basin; 1) Late Sequence Play, 2) Early Sequence Play, 3) Shallow Basal Sand Play, and 4) Seep Basal Sand Play. The Deep Basal Sand Play is located offshore and is not discussed in detail for this report. Two hydrocarbon test wells were drilled in the Kotzebue/Hope Basin near Cape Espenberg and Nimiuk Point. Both were drilled in the mid-70s by the Standard Oil Company of California (SOCAL). Cape Espenberg #1 was drilled in 1975 to a total depth of 8,373 feet. The drill hole did not have oil or gas shows, but indications of methane associated with coal seams were present during mudlogging. Four formation tests recovered salt and no hydrocarbons (Troutman and Stanley, 2002).

The following excerpt covers the three plays defined by MMS which may be present onshore in the KSPPA (Zerwick, 1995).

Late Sequence Play

This play includes all Oligocene and younger sediments. Reservoir rocks are most likely formed from shallow shelf or fluvio-deltaic sandstones. Results from the two exploratory wells drilled by SOCAL indicate that these rocks are highly porous. Results indicated the organic material in the wells were cellulosic, with hydrogen indices generally below 200 mgHC/g Total organic carbon (TOC). MMS concluded that any hydrocarbons produced from this play would probably be gas. Total organic carbon values average over 1.0%, but are associated with coals and confined to the upper, thermally immature part of the sequence (Mobil E&P, 1981). Only very small volumes of this sequence reach thermal maturity in the deepest parts of the basin, which are located offshore. Hydrocarbons would have to migrate into Late Sequence reservoirs from underlying, thermally mature sources in older sequences.

Traps within the Late Sequence play were formed during the second, or Miocene, stage of faulting, well before the deepest sediments reached thermal maturity, possibly in the Pliocene or Pleistocene time (Zerwick, 1995).

Early Sequence Play

This play consists of mostly of Eocene rocks. The Kotzebue basin wells penetrated rocks of Eocene age that are highly volcaniclastic and therefore subject to diagenetic processes of porosity destruction. Coupled with greater burial depth, this causes the reservoir potential of the Early Sequence play to be considerably lower than that of the Late Sequence play. It is speculated that the potential reservoirs consist of fluvio-deltaic sands and conglomerates deposited along the edge of the rift grabens. Organic material consists of cellulosic, hydrogen indices generally below 200mgHC/g TOC. Data from the two SOCAL wells indicated the TOC values averaged less than 0.5%, making the source potential very poor. Most of the Early Sequence sediments reached thermal maturity late in the deposition (primarily offshore) of the overlying Late Sequence (Oligocene and later). By that time faulting would already have formed abundant traps for migrating petroleum (Zerwick, 1995).

Shallow Basal Sand Play

The Shallow and Deep Basal Sand Plays were defined to acknowledge the possible existence of sands (inferred by resemblance to Norton basin) creating potential trap volumes at the base of basin fill. Potential source rocks would include the limited gas-prone organic material sampled in Early Sequence rocks in the two SOCAL wells. The Shallow Basal Sand Play, by definition is shallower than 10,000 feet, lies laterally apart from the zone of thermally mature strata. Lateral migration, unlikely because of the abundant faulting and apparent lack of a regional seal, would therefore be required to charge prospects in this play (Zerwick, 1995).

C. SELAWIK BASIN

The Selawik Basin lies to the east of the Kotzebue Basin and is considered an onshore extension to the Kotzebue Basin. There have been no exploration wells drilled to date. Much of basin includes the Selawik National Wildlife Refuge which is currently closed to oil and gas leasing. Two areas within the refuge boundary are classified as having moderate gas potential, and low oil potential. These areas are located in the northern and central portions of the refuge and occupy roughly 60% of the refuge.

The smaller of the two areas having moderate gas potential lies along the Kobuk River Valley and the Waring Mountains (approximately 800,000 acres). The moderate ranking corresponds to the Cretaceous sediments of the Kobuk trough. The low level of organic carbon content and the high thermal maturation of the sediments indicate it is unlikely significant amounts of hydrocarbons are present.

Any oil generated has likely been broken down into gas or driven off during one of the many periods of rock deformation (Teseneer and others, 1988).

The larger of the two areas lies along the Selawik River valley and includes the Kobuk River delta (approximately 1,100,000 acres). The moderate potential corresponds to the presence of Tertiary and Quaternary sediments. These sediments may be attributed to a source and reservoir for the accumulation of hydrocarbons, the presence of gas on the Baldwin Peninsula, and gas prone kerogens (Teseneer and others, 1988).

The remainder of the refuge (approximately 1,300,000 acres) has a low hydrocarbon occurrence potential. The low classification is derived from intrusive and extrusive igneous rocks that dominate the area. No oil and gas plays in the Selawik Basin are known at this time (Teseneer and others, 1988).

IV. PAST AND PRESENT OIL AND GAS EXPLORATION ACTIVITY

A. COLVILLE BASIN

The Colville Basin underlies the North Slope of Alaska and contains approximately 25 percent of U.S. oil reserves (Mull and Harris, 1998). Most exploration efforts and/or production associated with the basin have occurred in the NPRA and on State lands east of the reserve.

In 1945, the U.S. Navy began an 8-year exploration program of NPRA (known as Naval Petroleum Reserve No. 4 until 1976). Between 1945 and 1952, 45 shallow core tests and 36 test wells were drilled in and adjacent to NPRA (Gryc, 1985). This effort identified three noncommercial oil fields at Umiat, Cape Simpson and Fish Creek, and five noncommercial gas fields at Umiat, Barrow and Gubik. The Barrow gas deposits were developed and conveyed to the Barrow community in 1964.

In 1963, commercial drilling operations began in the basin and in 1968, the super giant Prudhoe Bay oil field was discovered.

Another 8-year federal exploration effort began in western Alaska in 1974, shortly after the Arab oil embargo, and was designed to augment domestic supplies of crude oil. A total of 28 test wells were drilled. None were commercial.

To date, the BLM has held NPRA lease sales in 1999, 2002 and 2004 resulting the drilling of 20 exploratory wells and the discovery of 3 fields. As of the end of 2004, the total number of exploratory wells (including core holes) drilled is about 470, an average of about one well per 400 sq mi in the province as a whole.

Oil and gas exploration has been relatively limited in the KSPPA to date. Exploration wells drilled in both the Colville Basin primarily tested large structures. Gas shows were encountered in the three Colville Basin wells

Exploration in the eastern Colville Basin (outside the planning area) has revealed large hydrocarbon accumulations that appear to decrease to the west. However, the presence or extent of oil and gas fields in the western Colville Basin is largely unknown. Exploration activities within the KSPPA have been limited to cartographic/geologic field work and three wells drilled, of which all encountered gas.

Tungak Creek #1, located on land owned by the Arctic Slope Regional Corporation (ASRC), was drilled by Unocal in December 1981. It reached a total depth of 8,212 feet. The purpose of the well was to test an anticlinal structure as it falls within the same Lower Brookian Sequence Foreland Basin Foldbelt (part of the USGS defined Thrust-Belt Play) as five other similarly structured gas pools (Wolf Creek, Gubik, Meade, Square Lake, and East Umiat) (Sherwood and others, 1995). Table 1 gives rough estimations of the five gas fields (Kumar and others, 2002), of which could serve as a guide to the amount of gas present at Tungak Creek. Potential reservoir sandstones are charged by traps that receive hydrocarbons from underlying, thermally mature, gas-prone shales of the Torok and Pebble Shale formations (Sherwood and others, 1995).

Table 1: Five gas fields in NPRA that fall within the same Lower Brookian Sequence as Tungak Creek

Gas Field	Estimated Reserve	Area (acres)	Test Rate
East Umiat	4 bcf	5,000	3-5 mmcfpd
Gubik	600 bcf	20,000	50 mcfpd
Meade	20 bcf	5,000	301-1132 mcfpd
Square Lake	58 bcf	5,000	0.1 mmcfpd
Wolf Creek	Local use only	8,000	116-881 mcfpd

Source: Kumar and others, 2002, Reed, 1958.

Eagle Creek #1 was drilled by Chevron in February 1978 and completed the following December. It reached a total depth of 12,049 feet in the Lower Cretaceous. The purpose of the test hole was to test structures in allochthonous rocks of the Brooks Range foothills (Moore and Potter, 2003). Eagle Creek #1 was drilled in the Thrust-Belt Play. Gas was recovered in drill stem tests from sandstones within the Nanushuk or Torok Formations (Sherwood and others, 1995). The well was plugged and abandoned.

Akulik #1, drilled by Chevron in April 1981, reached a total depth of 17,038 feet. Gas was recovered in drill stem tests from sandstones within the Nanushuk or Torok Formations. The well was plugged and abandoned.

Coalbed Natural Gas

Demand for natural gas has led to a sharp increase in coalbed natural gas (CBNG) drilling and production since 1996. High natural gas prices are making CBNG economically viable where it previously may not have been. Unlike conventional natural gas wells, CBNG wells produce at low gas rates (typically maxing out around 300 thousand cubic feet per day (Mcf/d) and can have large initial costs.

The coalbed natural gas resource beneath the Colville Basin is only partially realized. Conventional trapping, both stratigraphic and structural, are presumed to be the mechanism in place. The Colville Basin is generally characterized by folding and faulting along east-northeast and east trending axis generally parallel to the Brooks Range (Tyler and others, 2000).

The DGGS has chosen to focus on the western portion of the basin near Wainwright, Atqusuk (both outside of the planning area), and Point Lay (within the planning area) because of better coal exposures. Approximately 150 coal beds ranging from 5-28, with a few over 40 feet, have been documented. The majority of these beds display dominant face cleating. Spacing of the primary cleat in outcrops ranges between 0.25 - 0.75 inches. The surface fractures are an indication that the subsurface coal may have similar characteristics. The fractures would allow water and gas to flow into the wellbore. The high-volatile A bituminous coals are found at depths ranging between 300 - 6,000 feet (Tyler and others, 2000). These depths are suitable for exploration, in a relatively relaxed tectonic stress regime. Permeability could be enhanced by the underlying gently folded strata of the Meade and Wainwright Arches. Producibility of the coal could be enhanced by the coal lying within or near the base of the permafrost zone, which tends to increase gas concentrations (Smith, 1995). Well logs studied for the wellsites within the NPRA tend to show strong mud-log gas kicks below the permafrost zone and no mud-log gas kicks within the permafrost zone (Tailleur and Bowsher, 1979).

Coals associated with the Lisburne Field are Mississippian in age and primarily occur within the Kapaloak Formation. They crop out along the Lisburne Peninsula over a 45-mile north-south trending belt. Approximately 13 semi-anthracite coal beds have been identified along 2,200 feet of coastline. However, it is extensively faulted and folded. Because of this complex structure and distance to villages, these coals are not considered targets for coalbed natural gas development in the near future (Smith, 1995).

Additional exploration that could provide some useful data is that of two well sites found in western NPRA near the eastern KSP planning boundary. The NPRA wells have been analyzed to a greater extent with information more readily available than the three wells drilled inside the planning boundary.

The Tunalik wellsite (west of Wainwright) penetrated over 3,600 feet of coal-bearing section with coal beds estimated over 300 feet. The 1980 Husky Oil NPR Operations for U.S. Geological Survey report for Tunalik described several gas shows within the Nanushuk Group (5,000 - 6,000 foot depth) that were probably associated with coalbed natural gas. Further investigation by Tailleur and Bowsher in 1979, confirmed that the upper kilometer of the Tunalik Test Well reflected coal gas locked in clathrates to depths exceeding 350 meters. Coal encountered downhole below 500m showed no sign of methane, which would indicate methane-hydrate stability above that level.

Kaolak Test Well No.1 drilled through 4,500 feet of the Nanushuk Group with 255 feet of coal (Sable and Stricker, 1987). Two 10 foot beds and 2 thinner beds are within 1,000 feet of the surface and 32 beds ranging from 4 to 26 feet in thickness were recorded between 1,000 and 3,000 feet (Barnes, 1967). Between 1,183-1,203 feet lies a 17 foot coal bed with black, shiny coal with blocky fracture. Coalbed natural gas was discovered while drilling this section according to the drilling report published by the United States Geological Survey (USGS) (Collins and Bergquist, 1958).

B. KOTZEBUE/HOPE BASIN

The Kotzebue/Hope Basin had two oil and gas wells drilled by SOCAL in the mid-1970s; Cape Espenberg and Nimiuk Point. Cape Espenberg #1 was drilled in 1975 to a total depth of 8,373 feet. The drill hole did not encounter oil or gas, but indications of methane associated with coalbed gas were present during mud logging. Four formation tests were conducted but recovered only salt and no hydrocarbons (Troutman and Stanley, 2002).

Nimiuk Point #1 was drilled five miles west of the Selawik NWR boundary. The well was bored in the same locality as the conceptual Early Sequence Play. It reached a total depth of 6,311 feet. The well proved largely unsuccessful. A formation test was run between 3,537 and 3,755 feet in which a short blow was observed, but no gas was observed at the surface, making the test inconclusive. Gas zones identified in the by well logs were present from 1,130 feet to 1,132 feet, and from 1,158 feet to 1,160 feet, but were determined to be too thin to hold economic quantities of gas, if they in fact do contain gas. The well was abandoned as a dry hole (Troutman and Stanley, 2002).

Other exploration events included a well drilled in 1950 near Kotzebue to test for fresh water discovered high pressure gas a 238 feet and flowed for over 24 hours. In 1973, SOCAL discovered gas at a depth of 90 feet in a seismic shot hole on the Kobuk River Delta, 33 miles southeast of Kotzebue. Samples were taken and results indicated the gas to be 66% methane, 26% nitrogen, 6% oxygen, 2% carbon dioxide, and trace amounts of ethane and higher alkanes. A similar gas show was discovered 5 miles east in the delta at a depth of 65 feet and with similar lab results (Troutman and Stanley, 2002).

Coalbed Natural Gas

Coalbed natural gas potential in the Kobuk fields has not been estimated. Few reports and limited information leave much to speculate when it comes to the full extent of the coal resource. Published information indicates smaller coal seams are in the majority. Additionally, surface vitrinite-reflectance value of the Cretaceous coal-bearing rocks to both the north and south of the Kobuk Basin are very high (1.3 - 5%), suggesting coals may have already passed through the hydrocarbon-generating window. The ideal thermal maturity has a vitrinite-reflectance value of 0.8 - 1.0%. There is still potential for gas as it is largely unknown if the coals are permeable and have developed cleats. The Cretaceous sedimentary rocks in the area are characterized by low permeability. Further potential exists if the coal beds are laterally continuous, which could give rise to biogenic gas generation and accumulation. However, the amount of accumulation would depend on the localized coal bed geometry and the presence of permeability barriers for trapping the coal gases (Tyler and others, 2000).

C. SELAWIK BASIN

Oil and gas activity within the basin has been minimal. The area has been geologically mapped by the USGS during the late 1950s and early 1960s, with some additional recent mapping within select areas. There have been no oil or gas wells drilled in the basin.

Coalbed Natural Gas

Exploration for CBNG has been negligible within the Selawik Basin. Coal reserves are known to exist within the East and West Kobuk Fields as indicated by bituminous coal outcrops along the Singauruk River, Hunt River, lower Ambler River, lower Kogoluktuk River, and in the Lockwood Hills (Barnes, 1967). However, coal seams are not known to be of any substantial thickness, reported in the 2 - 3 foot range (Merritt, 1985), that would support the accumulation of hydrocarbons. The quantity of coal is unknown below the surface as no subsurface exploration was conducted within the Selawik Basin.

V. PAST AND PRESENT OIL AND GAS DEVELOPMENT ACTIVITY

Northern Alaska is a rich petroleum province, with an estimated in-place endowment of oil and gas equivalent to 77 billion barrels (Bbbl) and proven original oil reserves exceeding 20.5 Bbbl (ADNR, 2002), of which over 13 Bbbl have been produced to date. Exploration efforts in northern Alaska have located at least 38 oil and gas fields. Most reserves, however, are in a few, very large oil fields including Prudhoe Bay.

In 1968, Atlantic Richfield announced the discovery of the first commercial oil deposits at Prudhoe Bay, the largest producing oil field in the United States. Exploration and development grew dramatically and production began in 1977 with the completion of the 800-mile Trans-Alaska pipeline between Prudhoe Bay and the ice-free port of Valdez in Prince William Sound. The North Slope produced nearly thirteen billion barrels of oil and natural gas liquids by 1999, eighty percent of it from Prudhoe Bay, and thirteen percent of it from Kuparuk. Production of oil, condensate and natural gas liquids from North Slope fields peaked at 2.2 million barrels per day in 1988 and declined to 1.1 million barrels per day by 1999. Production is forecast to fall to about 408,000 barrels per day in 2021.

There are other areas in Northern Alaska with oil producing potential. Since 1968, the federal government has held several lease sales in the National Petroleum Reserve-Alaska, located to the west of Prudhoe Bay. Exploration and leasing is underway in that reserve, but no wells are in production. Significant national debate is occurring regarding possible oil development within the Arctic National Wildlife Refuge, to the east of Prudhoe Bay. Offshore of the north coast, the Northstar oilfield is under development in state waters, although approximately 20% of the oil reservoir is within the federal Outer Continental Shelf.

North Slope oil fields contain significant amounts of natural gas. Natural gas production on the North Slope was 3.2 trillion cubic feet in 1999, or about 8.7 billion cubic feet per day, ninety-three percent of which was injected into wells for enhanced oil recovery. This gas can be retrieved again once a gas transportation system is in place. The remaining gas is used as fuel for oil field equipment and pipeline operations, including the first four pump stations on the Trans-Alaska Pipeline. As an indication of the scale of the North Slope operation, the 219 billion cubic feet of gas consumed by North Slope operations nearly equals the total annual production of gas from all Cook Inlet fields. The East Barrow and Walakpa fields were developed in 1980 to provide natural gas for the community of Barrow. Construction of a natural gas pipeline from the North Slope to North American markets is currently under active consideration. Natural gas prices rose sufficiently in 2000 to improve the economics of constructing a gas pipeline to bring Prudhoe gas to market. Gas prices in the $3 to $3.50 per thousand cubic feet range are thought to be necessary for construction of a gas pipeline to be economic. Many factors will affect the economics of constructing a gas pipeline including route selection, price sustainability and volatility, increasing gas production elsewhere in the United States and the possible construction or expansion of liquefied-natural-gas terminals to handle expanded imports.

Following Atlantic-Richfield's discovery in 1968, exploration and development activity boomed on the North Slope. Thirty-three exploration wells were completed in 1969 in anticipation the state's lease sales of that year. The state offered over 450,000 acres along the Arctic coast between the Canning and Colville Rivers and earned $900,000,000 in bonus bids on 164 tracts. Since 1969, the state has conducted thirty-three additional lease sales on the North Slope and Beaufort Sea, resulting in thirty-six discoveries, many in the vicinity of Prudhoe Bay. Most of these post-Prudhoe discoveries are currently producing oil, taking advantage of the Prudhoe Bay infrastructure and proximity to the Trans-Alaska Pipeline. Five of these fields –Lisburne, Kuparuk, Milne Point, Endicott and Point McIntyre- are major fields. Fields more recently brought into production include the Badami (facing closure in 2003), Tarn, Alpine and West Sak. Production forecasts for each of these fields are available in the annual report of the Alaska State Division of Oil and Gas. Oil companies continue to increase total recovery from older, established Alaskan fields. Throughout the 1990s, an increasing number of development wells were recycled by re-drilling to new bottom hole locations. Due to rapid advances in directional drilling technology, the percentage of re-drilled wells increased from 8 percent in 1990 to 61 percent in 1999. This trend is especially evident in the Prudhoe Bay Field. During 1999, every reservoir penetration drilled within the field was a re-drill through an existing well bore.

The Northstar field represents one of the latest North Slope developments. During the late summer of 2001, three oil field modules were towed from the Port of Anchorage to the Beaufort Sea and installed at Seal Island (about six miles from Prudhoe Bay). The Northstar field contains an estimated 176 million barrels of recoverable oil, with production expected to peak at about 65,000 barrels per day, over a field life of some fifteen years.

Many factors will contribute to continuing production from North Slope oil fields including the state leasing program, additional fields coming on-line, improved oil recovery technology, improved drilling technology and higher oil prices.

No CBNG or conventional oil and gas development or production has taken place within the planning area to date. However, hydrocarbons are being developed and produced from the Colville Basin east of the Colville River, about 150 miles from the planning area. This includes the 500 million barrel Alpine field, the 2.5 billion barrel Kuparuk Field and Prudhoe Bay, the largest oil field in North America. Gas discoveries south of Barrow are produced for local consumption.

VI. OIL AND GAS OCCURRENCE POTENTIAL

A projection of future oil and gas activity must first consider where oil and gas resources might occur. Several geologic elements are necessary for oil and gas to accumulate in sufficient quantities. These elements include an organic-rich source rock to generate oil or gas, the combined effects of heat and time, a porous and permeable reservoir rock to store the petroleum in, and some sort of trap to prevent the oil and gas from migrating to the surface. Traps generally exist in predictable places - such as at the tops of anticlines, next to faults, in the updip pinchouts of sandstone beds, or beneath unconformities. Map 1 was drawn to show the occurrence potential for oil and gas throughout the KSPPA. It does not imply these resources can be developed economically.

The mineral occurrence potential assignment conforms to the rating system outlined in the BLM Handbook H-1624-1, Planning for Fluid Mineral Resources. This system is designed to remain dynamic. As new data is received it can be used to change the rating. The ratings used have four levels: high, medium, low and no known. The following definitions are used to classify the oil and gas occurrence potential:

HIGH---Inclusion in an oil and gas play as defined by the 1995 USGS National Assessment. In the absence of a play designated by the USGS, a high potential classification was assigned based on the demonstrated existence of: 1) source rock, 2) thermal maturation, 3) reservoir strata possessing permeability and/or porosity, and 4) traps.

MEDIUM---Geophysical or geological indications that the following may be present: 1) source rock, 2) thermal maturation, 3) reservoir strata possessing permeability and/or porosity, and 4) traps. Geological indication is defined by geological inference based on indirect evidence.

LOW---Specific indications that one or more of the following may not be present: (1) source rock, 2) thermal maturation, 3) reservoir strata possessing permeability and/or porosity, and 4) traps.

NO KNOWN---There is a demonstrated absence of a petroleum source, reservoir quality strata, or trapping mechanisms. Demonstrated absence is defined by physical evidence or documentation in the geological literature.

The rationale for determining occurrence potential within the KSPPA is based primarily on three sources; 1) geology, 2) oil and gas basins map of Alaska, and 3) conventional oil and gas play areas described by the USGS as a result of their 1995 National Oil and Gas Assessment. The play descriptions include discussions on reservoir rocks, source rocks, exploration status and resource potential.

Beikman, (1980), constructed a generalized geology map of Alaska. This information was used to identify areas within the KSPPA consisting primarily of igneous and metamorphic rocks. These areas were eliminated from further consideration as prospective oil and gas resources and assigned NO KNOWN potential. Ehm (1983) delineated three petroleum basins that fall either partially or entirely within the KSP. These basins are generally considered prospective for oil and gas resources and serve as the focus for further analysis using available exploration and drilling data and U.S. Geological Survey play descriptions.

The U. S. Geological Survey has identified eight conventional oil and gas plays in the KSPPA. A play is defined by the geological properties (such as trapping style, type of reservoir, and nature of the seal) that are responsible for the accumulations or prospects. Prospects are untested traps that could contain oil or gas or a combination of both. Typically, most prospects within a play are "dry" (lacking recoverable hydrocarbons). The fraction of all of the prospects within a play that may contain hydrocarbons (rather than water) can be viewed as a success rate for the play. This assessment methodology yields results that include probabilistic expressions of uncertainty. To stress the importance of this uncertainty, results reported here include 95% and 5% probabilities, in addition to mean values. The 95% probability level means that there is a 19 in 20 chance that the amount present will be at least as large as the amount shown; the 5% probability level means that there is a 1 in 20 chance that the amount present will be at least as large as the amount shown. Volumes of petroleum associated with the 95% and 5% probabilities are considered reasonable estimates of minimum and maximum volumes that may be present, and the mean is the average or expected value

Two principal categories of conventional plays were assessed by the USGS for their 1995 National Assessment; confirmed plays and hypothetical plays. A play was considered confirmed if one or more accumulations of the minimum size (1 million barrels of oil (MMBO) or 6 billion cubic feet of gas (BCFG)) had been discovered in the play. Hypothetical plays were identified and defined based on geologic information but for which no accumulations of the minimum size had, as yet, been discovered.

Using these definitions, four plays in the Colville Basin are confirmed and the remaining four plays are hypothetical. As such, hypothetical plays characteristically carry a much broader degree of uncertainty than do confirmed plays.

A. COLVILLE BASIN

Of the eleven oil and gas plays identified by the USGS in the Northern Alaska Province, eight occupy the northern portion of the KSPPA. The four confirmed conventional oil and gas plays; Topset, Turbidite, Ellesmerian-Beaufortian Clastics, and the Fold Belt Play have not been thoroughly explored in the planning area to date. There are no known oil or gas fields associated with these plays in the planning area.

Conventional Plays:

The Topset Play covers an area of roughly 16,906,528 acres, of which 138,748 acres (0.82 percent) are within the KSPPA. The play is of the Middle to Upper Brookian Sequence and contains the youngest petroleum-prospective rocks in the province. The occurrence of oil has been estimated by the USGS to contain 8 - 60 fields of 1 million barrels or greater in size. Likewise, gas occurrences could result in 2-90 gas accumulations with a calculated mean of 127.6 bcf. Potential reservoir rocks consist of sandstone and conglomerate where cumulative thickness could exceed half of the plays total thickness (9,000 feet). However, individual beds would rarely exceed 50 feet in thickness. Porosity within the western play area would be approximately 10 - 20 percent. Potential source rocks include the Hue Shale, the Kingak Shale, and the Shublik Formation. Proven oil sources for the play include the high-sulfur Barrow-Prudhoe-type oil and the low-sulfur Simpson-Umiat-type oil, both located east of the planning area (Magoon and others, 1996).

The Turbidite Play is approximately 19,502,459 acres, of which 298,169 acres (1.53 percent) are within the KSPPA. The play is from the Lower to Middle Brookian Sequence and includes turbidites of the Torok and Canning Formations. Resource potential of undiscovered oil (1 million barrels or more) is estimated to range between 10 - 110 accumulations. Between 5 - 80 undiscovered gas accumulations are estimated to occur with a calculated mean of 108.9 bcf. Reservoir rocks are primarily toe-of-slope or basin-plain turbidites. Sandstone bodies are thin and laterally discontinuous with potential reservoir thicknesses reaching 100 feet or more. Porosity varies from 5 to 30 percent, with porosity values higher in the east. Source rocks include marine shales of the Torok and Canning Formations, which are likely to be gas-prone. The Hue Shale is the richest oil-prone source rock known in the play interval and lies stratigraphically below the turbidites. Other oil-prone source rocks below this play include the Pebble shale unit, the Kingak Shale, and the Shublik Formation. Throughout most of the play, the top of the thermal zone of oil generation lies within or just below the lower part of the play interval. Oil has been discovered from turbidite reservoirs in numerous exploratory wells in the play east of the planning area (Magoon and others, 1996).

The Ellesmerian-Beaufortian Clastics Play is about 22,542,010 acres, of which 234,050 acres (1.04 percent) are within the KSPPA. The play consists of stratigraphic and structural traps of Permian to Early Cretaceous age. The interval consists primarily of siltstone and shale with minor sandstone. The play may be up to 6,000 feet thick at depths of 26,000 feet within the planning area. The size and number of undiscovered oil accumulations were not assessed by the USGS. However there may be 10 -1 40 gas fields ranging between 30 bcf and 4 tcf. Reservoir rocks include sandstones of the Echooka, Ivishak and Kuparuk Formations, Sag River Sandstone, Kemik Sandstone, and unnamed sandstone units in the Kingak Shale. All were deposited in shallow marine environments of the Early Cretaceous to Permian. Porosities may range from a high of 25 percent in the north to less than 10 percent in the southern play area. Source rocks include the Kavik Shale, Shublik Formation, Kingak Shale, the Pebble shale unit, and the Hue Shale. These shales, considered some of the richest source rocks on the North

Slope, range from marginally thermally mature in the north to overmature in the south. Exploration to date has revealed good oil and gas shows within the play. Good gas shows were encountered in the South Simpson and Tunalik wells (Magoon and others, 1996).

The Fold Belt Play covers an area of roughly 23,249,744 acres, of which 3,374,677 acres (14.51 percent) are within the KSPPA. The play primarily contains anticlinal traps in sandstone reservoirs within the Brooks Range fold and thrust belt. Play depths range from near surface to 20,000 feet. Resource potential of undiscovered oil (1 million barrels or more) is estimated to range between 1 and 20 accumulations. Undiscovered gas occurrences could result in 10-150 accumulations with a calculated mean of 212.7 bcf. Potential reservoirs include deltaic, shallow-marine, and turbidite sandstones. Porosity ranges from 5 to 30 percent with the lower porosity more representative of the western play area, including the KSPPA. Source rocks include several gas-prone shales of the Nanushuk Group, as well as the Canning, Sagavanirktok, and Torok Formations. They also include the oil-prone shales of the Hue Shale, pebble shale unit, Kingak Shale, and Shublik Formation. Within the planning area, the oil-prone rocks range from mature to overmature. Additionally, oil is less prospective in this play due to the thinning of the Hue Shale to the west. Several eastern province gas fields (see Table 2) are associated with this play including the; Gubik, East Umiat, Wolf Creek, Square Lake, and Meade gas fields (Magoon and others, 1996).

Hypothetical Plays:

The Lisburne Play covers an area of about 36,307,545 acres, of which 4,180,072 acres (11.51 percent) are within the KSPPA. It consists of structural and stratigraphic trapped carbonate or clastic reservoirs in the Lisburne Group. The play probably exists at depths between 10,000 (northern boundary) and 26,000 feet (southern boundary). Undiscovered oil potential was not assessed by the USGS, however, between 1 and 100 gas accumulations could be present with a calculated average of 287.6 bcf. The play is thought to have limited resource potential, all in the form of natural gas. Potential reservoir rocks include dolomite, limestone and sandstone, with the dolomite the most important of the three due to relatively high porosity values (occasionally as high as 25 percent). Limestone porosity is estimated at less than 5 percent and the sandstone is considered marginal in that it may be cemented partially or completely with calcite. Source rocks within the planning area could include a marine shale in the overlying Sadlerochit Group, marine shale and limestone in the Lisburne Group, and marine to lacustrine shale and coal in the underlying Endicott Group. Only a few wells have tested this large play area and many geologic uncertainties still exist.

The Lisburne Unconformity Play covers approximately 38,571,254 acres, of which 4,180,072 acres (10.84 percent) are within the KSPPA. Trapping is primarily stratigraphic, developed as a result of differential erosion on the Permian and Lower Cretaceous unconformities that lie at the top of the Lisburne Group. Oil and gas potential has not been assessed by the USGS. Reservoir rocks are primarily limestone and porous dolomite with depths ranging from 8,000 – 26,000 feet.

Potential source rocks in the planning area are gas-prone marine and non-marine shale. Approximately 50 wells may have penetrated this play but few were drilled with specific prospects as a target (Magoon and others, 1996).

The Endicott Play encompasses an area of roughly 36,758,155 acres, of which 4,180,072 acres (11.37 percent) are within the KSPPA. The play consists of combined structural and stratigraphic traps in sandstone reservoirs within the Kekiktuk Conglomerate of Mississippian age and sandstone or dolomite reservoirs of the overlying Kayak Shale. Play probability is estimated at 0.10. Oil and gas accumulations for the play were not assessed by the USGS. The Endicott Play extends southward to the northern Brooks Range at depths greater than 24,000 feet. Pay depths range between 12,000 and 24,000 feet. Due to extreme burial depths, porosity is estimated to be less than 10 percent. Potential source rocks include coal and lacustrine shale within the Kekiktuk Conglomerate and marine shale in the Kayak Shale. The northern part of the play may have poor to fair, gas-prone source rocks based on limited geochemical data. The source rock within the planning area is deemed to be thermally supermature (Magoon and others, 1996).

The Western Thrust Belt Play covers approximately 10,350,043 acres, of which 2,472,913 (23.90 percent) are within the KSPPA. The play consists primarily of structural traps in Carboniferous carbonate reservoirs within the Brooks Range fold and thrust belt. Play probability is estimated at 0.22. Undiscovered oil potential projects between 1 - 45 accumulations of 1 million barrels or more. Undiscovered gas occurrences could result in 10 - 150 accumulations with a calculated mean of 278.1 bcf. The primary reservoir rock is the carbonate rocks of the Lisburne Group. Drilling depths of the reservoir rock range form near surface to 35,000 feet. Potential source rocks consist of marine shale of Mississippian to Cretaceous age. Mississippian, Triassic, and Jurassic oil shales are local occurrences and not considered to be a characteristic of the entire play. Within the planning area, the play displays a higher level of maturity than it does to the east. Exploration has been limited with only four exploratory wells drilled to date. To further restrict analysis, data for three of wells remains proprietary.

Coalbed Natural Gas

High-rank coal is abundant throughout the Northern Alaska Coal Province in thick accumulations and at depths that hold potential for large quantities of coalbed natural gas. The planning area lies within the Arctic Foothills Subprovince and contains three known coal fields of bituminous rank; Lisburne Field, Cape Beaufort Field and the Kukpowwruk Field.

Table 2: Size of undiscovered accumulations. A Truncated Shifted Pareto (TSP) model describes a "J shaped" field-size distribution. For a detailed description of TSP Factor see Houghton and others, 1993.

Confirmed Play	Oil Accumulations Median	Gas Accumulations Median	F5 of Largest Accumulation Oil	F5 of Largest Accumulation Gas	TSP Factor Oil	TSP Factor Gas	Mean Accumulation Oil	Mean Accumulation Gas
Topset	20 mmb	75 bcf	500 mmb	1 tcf	6	4	57.9 mmb	127.6 bcf
Turbidite	8 mmb	30 bcf	400 mmb	2 tcf	6	7	22.0 mmb	108.9 bcf
Ellesmerian-Beaufortian Clastics	---	30 bcf	---	4 tcf	---	7	---	108.9 bcf
Fold Belt	25 mmb	75 bcf	1,150 mmb	2.5 tcf	6	6	72.9 mmb	212.7 bcf
Hypothetical Play								
Lisburne	---	100 bcf	---	4.6 tcf	---	6	---	287.6 bcf
Lisburne Unconformity	Not Quantitatively Assessed							
Endicott	Not Quantitatively Assessed							
Western Thrust Belt	30 mmb	135 bcf	500 mmb	2 tcf	5	--	62.2 mmb	278.1 bcf

Table 3: Number of Undiscovered Accumulations

Confirmed Play	Oil Minimum	Gas Minimum	Oil Median	Gas Median	Oil Maximum	Gas Maximum	Oil Mean (Calculated)	Gas Mean (Calculated)
Topset	8	1	22	2	60	5	27.0	2.4
Turbidite	10	5	55	40	110	80	57.1	41.0
Ellesmerian-Beaufortian Clastics	0	10	0	35	0	140	0.0	51.7
Fold Belt	1	10	7	50	20	150	8.5	62.5
Hypothetical Play								
Lisburne	0	1	0	10	0	100	0.0	13.7
Lisburne Unconformity	Not Quantitatively Assessed							
Endicott	Not Quantitatively Assessed							
Western Thrust Belt	1	2	12	20	45	90	3.6	6.8

Table 4: API Gravity and Accumulation Depth

Confirmed Play	Minimum API Gravity	Mean API Gravity	Maximum API Gravity	Minimum Oil Depth	Minimum Gas Depth	Median Oil Depth	Median Gas Depth	Maximum Oil Depth	Maximum Gas Depth
Topset	10°	17°	25°	100 ft	2,000 ft	4,000 ft	4,000 ft	9,000 ft	9,000 ft
Turbidite	19°	22°	44°	500 ft	500 ft	8,000 ft	8,000 ft	18,000 ft	18,000 ft
Ellesmerian-Beaufortian Clastics	---	---	---	---	2,000 ft	---	10,000 ft	---	26,000 ft
Fold Belt	19°	30°	54°	100 ft	100 ft	4,000 ft	4,000 ft	15,000 ft	25,000 ft
Hypothetical Play									
Lisburne	---	---	---	---	9,000 ft	---	25,000 ft	---	30,000 ft
Lisburne Unconformity	Not Quantitatively Assessed								
Endicott	Not Quantitatively Assessed								
Western Thrust Belt	19°	30°	54°	1,000 ft	1,000 ft	6,000 ft	10,000 ft	12,000 ft	35,000 ft

Significant hydrocarbon research in the planning area has occurred near Eagle Creek. Eagle Creek is located approximately 40 miles north of Red Dog on land managed by the Arctic Slope Regional Corporation. Mapping and analysis from the DGGS, USGS and the University of Alaska Fairbanks, revealed an area of anomalously low thermal maturity in which the rocks had not been heat as much from burial and mountain building activities as in adjacent areas. These cooler areas were termed “oil windows,” while the overcooked areas would only have dry gas potential (Mickey and others, 1998).

Geological and geochemical analysis have indicated organic-rich oil and gas-prone Late Triassic, Early Jurassic, and Early Cretaceous source rocks are present in the foothills of the Delong Mountains near the Thetis Creek headwaters. Table 5 shows the results from samples taken from the area (Mull, 2000).

East of Thetis Creek toward the Kukpowruk River, Jurassic and early-Cretaceous rocks were concurrent with the rocks from Thetis Creek and are thermally overmature for the generation of oil, but could be the source of migrated fluid and gaseous hydrocarbons. Further studies have indicated that these source rocks are probably structurally overridden to the east by thrust sheets of the northwestern DeLong Mountains (Mull, 2000).

Table 5: Geochemical results from rock samples in the western Colville Basin.

Name	Total Organic Carbon (TOC)	Hydrogen Index	TMax	Vitrinite Reflectance (R_o)
Thetis Creek Headwaters	21%	560	420-430	0.6-1.19%
Surprise Creek	4.6%			0.74-1.16%

East of Thetis Creek, an anomalous exposure of the Shublik Formation of the Upper Triassic is located at Surprise Creek. At this location, the Shublik Formation is a rich source rock with up to 4.6% TOC with Type II oil-prone Kerogen (Mull, 2000).

B. Kotzebue/Hope Basin

No previous RFDs have been written for this portion of the Kotzebue/Hope Basin in the planning area. The basin lies primarily offshore beneath Kotzebue Sound. Most exploration efforts and all the production associated with the basin have occurred east of the planning area within the NPRA and on State land. Eight conventional oil and gas plays have been identified and extend from NPRA into the KSPPA.

The Late Sequence Play includes all Oligocene and younger sediments. Reservoir rocks are most likely formed from shallow shelf or fluvio-deltaic sandstones. Results from the two exploratory wells drilled by SOCAL indicate that these rocks are highly porous. Results indicated the organic material in the wells were cellulosic, with hydrogen indices generally below 200 mgHC/g TOC. MMS concluded that any hydrocarbons produced from this play would probably be gas. Total organic carbon (TOC) values average over 1.0%, but are associated with coals and confined to the upper, thermally immature part of the sequence (Mobil E&P, 1981). Only very small volumes of this sequence reach thermal maturity in the deepest parts of the basin, which are located offshore. Hydrocarbons would have to migrate into Late Sequence reservoirs from underlying, thermally mature sources in older sequences. Traps within the Late Sequence play were formed during the second, or Miocene, stage of faulting, well before the deepest sediments reached thermal maturity, possibly in the Pliocene or Pleistocene time (Zerwick, 1995).

Early Sequence Play: This play consists of mostly of Eocene rocks. The Kotzebue basin wells penetrated rocks of Eocene age that are highly volcaniclastic and therefore subject to diagenetic processes of porosity destruction. Coupled with greater burial depth, this causes the reservoir potential of the Early Sequence play to be considerably lower than that of the Late Sequence play. It is speculated that the potential reservoirs consist of fluvio-deltaic sands and conglomerates deposited along the edge of the rift grabens. Organic material consists of cellulosic, hydrogen indices generally below 200mgHC/gTOC. Data from the two SOCAL wells indicated the TOC values averaged less than 0.5%, making the source potential very poor. Most of the Early Sequence sediments reached thermal maturity late in the deposition (primarily offshore) of the overlying Late Sequence (Oligocene and later). By that time faulting would already have formed abundant traps for migrating petroleum (Zerwick, 1995).

Shallow Basal Sand Play: The Shallow and Deep Basal Sand Plays were defined to acknowledge the possible existence of sands (inferred by resemblance to Norton basin) creating potential trap volumes at the base of basin fill. Potential source rocks would include the limited gas-prone organic material sampled in Early Sequence rocks in the two SOCAL wells. The Shallow Basal Sand Play, by definition is shallower than 10,000 feet, lies laterally apart from the zone of thermally mature strata. Lateral migration, unlikely because of the abundant faulting and apparent lack of a regional seal, would therefore be required to charge prospects in this play (Zerwick, 1995).

PLAY			PORE		N (MPRO)		Reserves		Undiscovered Potential	
			Ac/Ft	Ac/Ft	No. Pools		Gas	Oil	Gas	Oil
No.	UAICode	Name	mu	sig.sq.	Mean	Max	(BCF)	(MMB)	(BCF)	(MMB)
1	UAHB0101	Late Sequence Play	12.843	1.1839	8.7	40	0	0	3341	90
2	UAHB0201	Early Sequence Play	12.100	1.0140	5.4	34	0	0	387	11
3	UAHB0301	Shallow Basal Sands Play	11.628	0.9317	5.9	48	0	0	333	9
4	UAHB0401	Deep Basal Sands Play	11.619	0.8951	0.2	6	0	0	4	0.1

		MEAN POOL SIZES OF RANKS 1 TO 3					
		Pool #1		Pool #2		Pool #3	
PLAY		Gas	Oil	Gas	Oil	Gas	Oil
No.	Name	(BCF)	(MMB)	(BCF)	(MMB)	(BCF)	(MMB)
1	Late Sequence Play	1784	46	979	26	704	18
2	Early Sequence Play	272	7	152	4	110	3
3	Shallow Basal Sands Play	235	6	140	4	106	3
4	Deep Basal Sands Play	30	1	15	0	10	0

VII. OIL AND GAS DEVELOPMENT POTENTIAL

The potential for oil and gas development for the entire Kobuk-Seward Peninsula planning area is shown in Map 2. This is a baseline scenario and projects development for the life of the plan based on the assumption that all areas are open to development under standard lease terms and conditions except those areas closed by statute or for discretionary reasons.

Areas are assigned one of five ratings; high, medium, low, very low and no known development potential. This projection is based on the available data and professional judgment. The timing of the drilling and the areas receiving the greatest attention is difficult to predict. Actual development activity will be determined by accessibility to resources, including the perceived impact of lease stipulations by the petroleum industry; exploration and development costs; the success rate of wells drilled in the future; commodity prices; and production rates that provide an economically viable return on investment.

A. COLVILLE BASIN

Topset Play

The Topset Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. About 250 exploratory wells have penetrated the formations of the play, but relatively few have been drilled for prospects within the play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure and the fact that a small fraction of the play (less than 1 percent of the total play) lies within the planning boundary. Oil discoveries within the Topset play are located at the Fish Creek well (1949) and the Simpson oil field (1950), both located in NPR-A, and in the Schrader Bluff pool of the Milne Point field (1969).

Turbidite Play

The Turbidite Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. More than 200 exploratory wells and 2,000 development wells have penetrated the formations of the play, but relatively few have been drilled for prospects within the play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure and the fact that a small fraction of the play (less than 2 percent of the total play) lies within the planning boundary. Oil discoveries within the Turbidite Play are located at Flaxman Island, Badami, Stump Island pool of Point McIntyre field, and Colville Delta. The Stump Island pool is currently producing along with production from deeper Kuparuk

Formation reservoirs. Oil has been recovered from turbidite reservoirs in numerous exploratory wells in the play.

Ellesmerian-Beaufortian Clastics Play

The Ellesmerian-Beaufortian Clastics Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. Less than 50 exploratory wells have penetrated the formations of the play, but few have been drilled for prospects within the play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure and the fact that a small fraction of the play (about 1 percent of the total play) lies within the planning boundary. Oil and gas shows have been recorded in several wells in this play and good gas shows have been encountered in the South Simpson and Tunalik wells. The lone oil discovery within the Turbidite Play is the Walakpa gas field (1977) in NPR-A.

Fold Belt Play

The Fold Belt Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. About 50 exploratory and delineation wells have tested 30 structures in the play area (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure and the fact that only about 15 percent of the total play is represented within the planning area boundary. In addition, the western part of the play, including the KSPPA, is considered less oil prospective than the eastern part which contains greater thicknesses of the oil-prone Hue Shale. Oil and gas discoveries within the Fold Belt Play include six non-economic accumulations: Umiat oil field (1946), Umiat gas field (1946), Gubic gas field (1951), Wolf Creek gas field (1952), Square lake gas field (1952), East Umiat gas field (1963), and Meade gas field (1950). The USGS believes the number of untested structures in this play may number more than 100.

Lisburne Play

The Lisburne Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. Less than a 12 exploratory wells have been drilled for prospects in this play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure, no know hydrocarbon accumulations, and less than 12 percent of the total play is represented within the planning area boundary. In addition, many geologic uncertainties exist because of the lack of exploratory drilling to date over the large area covered by this play. These uncertainties include reservoir distribution, continuity, and thickness, as well as trap size and seal integrity and source rock richness.

Lisburne Unconformity Play

The Lisburne Unconformity Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. As many as 50 exploratory wells may have penetrated the formations in this play, but few, if any, were drilled for prospects (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure, the small probability of favorable reservoirs and adequate traps, and the fact that less than 11 percent of the total play is represented within the planning area boundary.

Endicott Play

The Endicott Play is classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. Less than 12 exploratory wells have been drilled for prospects in this play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure, no know hydrocarbon accumulations, and the fact that less than 12 percent of the total play is represented within the planning area boundary. In addition, many geologic uncertainties exist because of the lack of exploratory drilling to date over the large area covered by this play. These uncertainties include reservoir distribution, continuity, and thickness, as well as trap size and seal integrity and source rock richness.

Western Thrust Belt Play

The Western Thrust Belt Play classified as a lightly explored area with **High** potential for the generation of oil and gas and **Low** development potential within the planning area. Only 4 exploratory wells have been drilled in this play (Magoon and others, 1996). The low development potential is due primarily to the planning area's distance from oil and gas infrastructure, no know hydrocarbon accumulations, and the duration of deformation which may have compromised trap integrity. The greatest potential for petroleum in the Western Thrust Belt Play is expected to be along the immediate range front and foothills to the north.

VIII. RFD BASELINE SCENARIO ASSUMPTIONS AND DISCUSSION

This baseline scenario projects development on the assumption that all areas are open to exploration and development under standard lease terms and conditions except those areas closed by statute or for discretionary reasons. It is also assumed that the oil and gas resources occurring in large pools (i.e., reservoirs that can be developed profitably at certain commodity prices) will be both discovered and developed by industry.

The Kobuk-Seward Peninsula planning area is considered a “frontier” area with respect to oil and gas exploration and development. The term frontier refers to oil and gas development in a remote and largely undeveloped area such as the western Arctic Slope. According to BLM Handbook H-1624-1, Planning for Fluid Mineral Resources, “... projections should be based on past and present leasing, exploration, and development activity as well as professional judgment on geological and technological and economic factors. Extrapolations of historical drilling and/or production activity may be used as the basis for projections.”

The Bureau’s policy regarding reasonably foreseeable development of fluid mineral resources in frontier areas requires that a minimum level of exploration and development activity be projected for the purpose of impact analysis. For these areas, and for areas of low development potential, an assumption is made that a baseline discovery will involve certain exploration activity leading up to a discovery and subsequent development activity. The timing of a discovery and subsequent oil and gas development within the planning area is difficult to predict. However, it is not likely to occur during the life of this plan. Industry has shifted from exploring completely untested (wildcat) geologic plays in remote areas of the Arctic Slope to a detailed re-examination of proven plays in areas near existing infrastructure. Oil fields developed near the Prudhoe Bay field, which can be processed with existing infrastructure, have an advantage over more remote fields, where stand-alone facilities, longer access roads and pipelines must be installed. Applying this strategy, exploration of proven plays is more likely to be successful and the economics for development become more favorable if existing infrastructure is used. Consequently, new development is likely to expand incrementally from current North Slope infrastructure rather than appear as widely scattered startup projects.

The search for large structural traps dominated North Slope exploration in the early 1980’s. Explorers believed the minimum economic field size of prospects located outside the Prudhoe Bay infrastructure was one billion barrels of recoverable oil. The discovery in 1994 and subsequent development of the Alpine field changed this long-standing belief. Alpine is the western-most producing oil field on the North Slope.

The Alpine field represents the most recent and efficient comparatively large-scale development on the North Slope. It is used as the development model for this RFD scenario based on a field size large enough to be considered economically developable about anywhere in Alaska. Original Alpine in-place oil was estimated at one billion barrels with 250-300 million barrels of oil reserves. The field began producing in November 2000, and with daily volume at 100,000 barrels, the field is now estimated to produce 500 million barrels of oil over its 25-year life (Gingrich 2001).

While the largest fields, Prudhoe and Kuparuk are nearing the end of their productive life, smaller, more numerous satellite oil and gas reservoirs are being developed and produced. In addition, new companies have entered the Alaska crude oil and gas exploration sector in recent years and interest should continue to grow, especially among independent exploration and production companies and in areas beyond the mature oil provinces of the North Slope and Cook Inlet. In the long term, oil production will continue its gradual decline, supplemented with smaller field-size oil development and with gas field development in or near existing infrastructure.

Technological changes and innovative operation procedures such as long-reach drilling, reduced pad size, reserve pit elimination, underground injection of disposed drilling fluids, ice roads and pads, centralized waste management and recycling, and advanced facilities design have reduced exploration and development costs and helped to shrink the minimum economic field size.

Typically, the largest fields are discovered and developed first, and subsequent discoveries are smaller and more costly to develop on a per-barrel basis. However, it is assumed that not all prospects will be tested or that all economic resources will be discovered by drilling. At some point, exploration is directed to other basins and some of the potentially economic resources are not produced.

A. PROJECTION OF OIL AND GAS LEASING ACTIVITY

Under this baseline exploration and development scenario, about 6.3 million acres of the KSPPA, represented by the play boundaries identified by the 1995 USGS assessment, would be made available for future leasing. Historical leasing patterns in the western Arctic Slope are used in this RFD to support the possible range and scale of activities associated with future lease sales in the planning area. In previous NPR-A leasing programs, 3.6 million acres were leased from the nearly 20.5 million acres offered (about an 18 percent lease rate). Statistics compiled by the Alaska Division of Geological and Geophysical Surveys (Kornbrath,1995) for its oil and gas lease sale program indicate that about 50 percent of the tracts offered in state oil and gas lease sales have been leased. Applying these leasing rates to the planning area, between 1.2 and 3.2 million acres would ultimately be leased. We have chosen the 1.2 million acres figure for this RFD based on the planning area’s proximity to the NPR-A and the similarities of defined oil and gas plays. This translates to about 710,000 acres of BLM-administered lands to be leased in the KSPPA under this scenario based on the percentage (60 percent) of BLM-administered lands within the proposed leasing area.

B. PROJECTION OF EXPLORATION

Current North Slope technology depends on airstrips and ice roads which may not be applicable in the southern portion of the proposed leasing area where the terrain is neither flat nor gently rolling. It is assumed that all references to ice pads and ice roads in this scenario reflect activities that would occur in the northern region of the proposed lease sale area. Gravel pads and roads would most likely be required for oil and gas activities in the southern lease sale area.

Seismic surveys

Seismic survey work is likely to precede exploratory drilling for oil and gas. Onshore seismic acquisition on the North Slope occurs during the winter after the federal, state and local governments issue permits authorizing tundra travel. Tundra travel begins when the tundra is frozen and there is six inches of snow cover. Specialized low-impact tundra travel vehicles weighing more than 10 tons are used. However, the tracks are long and wide, spreading the pressure over a large area to protect the tundra from damage. It is assumed that seismic exploration within the KSPPA would range from 150 to 800 seismic (2-D) line-miles every four years over the life of the plan. This range is based on a four-year, 600 line-mile seismic exploration program that lead to the discovery of the Alpine field, and on historic seismic exploration in the NPR-A over a 28 year span from 1972 and 2000. During that period, about 21,000 line-miles were shot over an area of about 23 million acres.

Modern seismic data acquisition uses vibrator trucks, and rarely, dynamite. Crews are housed in mobile camps on the seismic train and supported by either ground vehicles or aircraft. BLM grants permits with requisite operational stipulations designed to protect the environment and specific sites from potential adverse affects for seismic activities on Public Lands. All gathered seismic data on the Federal mineral estate are submitted to BLM for interpretation and analyses even though the data are proprietary and held confidential.

The acquisition of 3-D seismic data is a key step in the exploration process. It is used to identify and map the prospects of interest. Successful and accurate interpretation results in more efficient drilling with fewer dry holes, better drill pad positioning and higher petroleum recoveries. 3-D seismic modeling also facilitates immediate production enhancement from water and miscible fluid flooding for optimal resource recovery. These resource recovery enhancement practices result in more efficient resource utilization and lead to better economics for determining an economically developable field. In preparation for field development, it is assumed that a 130 square mile 3-D seismic survey would be acquired during the winter months following the discovery. This is based on a similar program conducted after the discovery of the Alpine field. Depending upon terrain conditions, 3-D seismic crews can collect up to about 10 square miles of data per day (Banet, unpublished report, 2003). The resulting 3-D structure and fault map would be used to position the horizontal wells to be drilled for field development.

Exploratory drilling

Using the past 33 years of modern drilling activity in the western Arctic Slope to determine the average rate of wildcat drilling, approximately seven wells are drilled every five years. Given a planning period of 15 years, one would conclude that 21 exploration wells would be drilled in the planning area. To date, industry has drilled 19 exploratory wells with 17 wells drilled on 1999 leases within the Northeast NPR-A Planning Area. In the outer continental shelf, 35 exploration wells were drilled from a lease inventory of 5.5 million acres (averaging 1 well per 27 leased tracts).

Another possible development scenario, reflecting the higher end of projected exploration activity, assumes that the next 15 years would be similar to the most active 15-year period the western Arctic Slope has experienced. Again, using the past 33 years to base the analysis, the most active 15-year period for the planning area was from 1976 to 1991, with 33 wells drilled. Therefore, a reasonable exploratory drilling scenario for the planning area would range from 21 to 33 wells. Using the 33 well scenario and the wildcat success ratio for frontier areas of 2.5 percent (or 1 in 40 wells) (Chevron 1998), only one well is likely to have a sufficient show of hydrocarbons to be declared a discovery and to warrant the drilling of additional wells within the planning area. However, the success ratio for commercial fields on the North Slope has been about 5 percent (or 1 in 20 tested prospects is likely to be commercially developed). Petroleum exploration in Alaska has discovered some of the largest oil fields in North America and can be a high-reward venture, but the chances for commercial success for any particular exploration well are small.

Drilling is the sole method of confirming the existence of a hydrocarbon accumulation in a mapped prospect. Four gravel staging areas of 6 acres each would be located within the planning area to receive and store equipment and materials used to support the winter exploration program. Ocean barges would transport materials to Cape Lisburne, Point Lay or Wainwright during the summer season followed by overland moves to exploration pads using ice roads or hardened snow trails during the winter months. Exploration drilling operations on the tundra would include surface water flooding on the pad site to build up progressive ice layers, mobilizing an exploration drill rig and providing accommodations for a crew. A typical ice pad is 1 foot thick and requires about 500,000 gallons of water. Logging facilities, mud system trailer and storage tanks, drill pipe, tool shed and generators expands the pad area to approximately 3 to 10 acres depending on well location. Current drilling technology is self-contained. There are no reserve pits that could leak or pose an attractive nuisance to wildlife. Traditionally, drilling muds and cuttings have been placed in surface waste disposal impoundments known as reserve pits. Using grind and inject technology, cuttings are now crushed and slurried with seawater in a ball mill, then combined with the remaining drilling muds and reinjected into a confining rock formation 3,000 to 4,000 feet underground in an approved injection well. This permanent and environmentally sound disposal method isolates the wastes, eliminates subsequent disposal problems and greatly reduces the spaced required for drilling operations. Approximately 80% of the muds and additives are reconditioned and recycled.

Pre-drilling site preparation and rig set up for a test to approximately 10,000 feet takes one to four weeks depending on access and terrain. Drilling to total depth on the western Arctic Slope, where the stratigraphic succession is comparatively poorly known, should be accomplished within three to four weeks. By contrast, central Arctic Slope drilling to similar depths takes about 10 to 14 days. If there are favorable indications, testing and additional sidetracking for coring and sampling can take another month. Unforeseen conditions could lengthen the drilling project. In eastern NPR-A, it is not unusual to build 60 to 70 miles of ice roads in a winter drilling season to support remote operations. Ice-based exploration activities leave no permanent damage to tundra. However, helicopter based and supported facilities are currently in use at remote and environmentally sensitive areas world wide. Extensive helicopter support can be addressed in permitted exploration stipulations.

The discovery of commercial oil or gas would require year-round development and production activities. Field life is approximately 20 to 30 years, but larger fields may produce up to 50 years. Under this RFD scenario, the discovery field is estimated to produce for about 25 years. Based on the USGS play analysis of the Colville River Basin, both oil and gas may be found in the planning area. However, it is assumed that this field would be a commercial oil producer, as gas on the North Slope currently lacks a transportation system to market. The discovery of oil would initiate additional exploration efforts within the planning area and result in the drilling of 10 additional exploration wells.

C. PROJECTION OF DEVELOPMENT

Delineation wells

Several delineation (confirmation) wells are likely to be drilled before a commitment is made to project development and another drilling season is utilized. To define the limits of the reservoir after the discovery, it is assumed 15 delineation wells would be drilled. Depending upon the depth of the potential reservoir and the size of the mapped prospect, these confirmation wells can be drilled from the same facility. Large discoveries (approximately 200 million barrels or more) would likely require an additional drill site for confirmation. In this scenario, the discovery is similar in size to the Alpine field, approximately 1 billion barrels of oil with gross recoverable reserves of 500 million barrels. Therefore, delineation wells averaging about 6 acres each would be drilled from additional drill sites. Typically, after analyses of the data and subsequent geotechnical description of the reservoir exploration, wells are not used for production purposes. Following test completions, wells are plugged with cement to seal off zones capable of flowing hydrocarbons or formation waters. This protects the surface and subsurface permeable zones from contamination by migrating formation fluids (i.e., oil, salt water, gas, etc). The rig and its support constructions are moved, all wastes are disposed and no foreign materials remain onsite.

Modern infrastructure is virtually nonexistent in the western Arctic Slope beyond the roads and airstrips of the villages. This entire area remains remote. Outside the few villages, there are only a few unmanaged airstrips and a dock built to support production at Red Dog zinc mine. All facilities relating to oil or gas production would have to be built before operations could begin. Current technology co-locates drilling and production facilities in comparatively smaller and more efficient facilities. Drilling pad sizes have been reduced over 80% from older pad designs by utilizing closer wellhead spacing and by eliminating all reserve pits. Gravel resources needed for the sites are dramatically reduced. Oil and gas production now includes the ability to have fewer drilling pads. Multiple reservoir targets, several miles away can be reached from centralized drill pads and extended reach drilling. Multiple completions from a single well bore increase well productivity. These practices enable smaller sized fields to be developed economically. Fewer and smaller pads translate into less potential for adverse impact to the environment.

Discovery field

It is assumed that the discovery field will comprise 40,000 acres and produce from 114 horizontal wells (roughly 57 injector wells and 57 producers) located on two drill sites, three miles apart. The gravel pads will be joined by a 35-foot wide, five-foot thick gravel road (40,000 cubic yards of gravel per mile) that will also serve as an airstrip. The main pad would also serve as a stand-alone central processing facility (CPF) and would not be connected by a gravel road to existing infrastructure on the North Slope. The operation will be much like that of an offshore platform. A staging area for field development would be built during the winter months prior to development activities and may require up to 150 acres. Drilling supplies and major equipment will be transported in winter using ice roads. Food and personnel will be transported by air to an adjoining 5,000-foot gravel airstrip.

The C-130 Hercules and DC 6 are the cargo support aircraft of choice for industrial support in Alaska. They can land upon a variety of surfaces and take off in short distances. However, for an acceptable margin of safety for production activities, an industrial-sized, all-weather airstrip would be 150 to 200 feet wide and 5,000 feet long, with potential to cover 20 to 30 acres. It would require approximately 140,000 to 200,000 cubic yards of gravel. The volume of gravel varies significantly, because the amount required depends upon the nature of the substrate. Permafrost and extensive poor drainage would pose problems to any construction on tundra. Consequently, a gravel airstrip would need to be 5 feet thick. Gravel required for construction will most likely be mined during the winter months to reduce impacts and be located as close to the field as feasible using two or three separate deposits, 20 to 50 acres in size, to minimize environmental impacts.

Gathering lines, three to twelve inches in diameter, will run from the remote satellite pad to the CPF pad. One line will transport the crude oil and a parallel set of lines will transport the gas and water from the CPF to the remote pad for fuel, injection, or disposal. These lines will be elevated on steel vertical support members. Above ground installations allows ready access to pipelines year-round to perform corrosion inspection, leak detection and maintenance.

Surface impact (gravel footprint) of the initial discovery will comprise about 100 acres (Map 3) and would require about 1,000,000 cubic yards of gravel (Banet and others, unpublished report, 1987). The permanent production operation consists of a remote drill pad, connecting gravel road and parallel pipeline, main pad/central processing facility (CPF) and a production pipeline to transport the oil to market.

Central processing facility

The CPF is the long-tern operational hub facility. It consists of oil production equipment comprising three phase separators (oil, gas, water), gas-conditioning equipment which separates/strips natural gas from the liquid stream, the pipeline gathering and monitoring system which maintain pressure regulation and well monitoring and control systems. The filtering and conditioning process separates out all water, gas and scale before sending the oil stream through the metering system to the production pipeline. Both water and gas byproducts are typically repressurized and reinjected through service wells to maintain reservoir pressure or used (in the case of the gas) for the facility. The water is chemically treated to remove scale and bacteria. Living quarters for the drilling and production crews are at the CPF. It is also the site for offices, monitoring equipment, maintenance shops, wastewater treatment, power generators and communications. Water for domestic use would be obtained from local lakes or streams. Insulated tanks would store sufficient amounts of potable water. Sewage treatment facilities and the incinerator would eliminate most of the human waste and trash. Items that could not be burned would be transported to an approved disposal facility. Fuel storage would hold diesel and other refined petroleum products necessary for operating the equipment on the CPF. Electricity would be provided by a diesel or natural gas powered generation plant.

D. PROJECTION OF PRODUCTION

An oil or gas discovery has to get its product to market. Pipelines are the most efficient means of transportation across remote and undeveloped areas. It is assumed an elevated (7 feet off the ground) 24 inch diameter production pipeline would be sufficient to carry the estimated 80,000 to 100,000 barrels of oil per day (BOPD) from the field. This pipeline would be about 350 miles long and constructed during the winter months. It is designed to transport more oil with the addition of pumps. Elevated pipelines are easier to build, monitor and have not adversely affected animal populations where studied. In addition, comparatively smaller water and gas return lines accompany the main pipeline. Vertical support members (VSM) would be spaced 50 to 70 feet apart.

Satellite fields

It is assumed that four additional discoveries would be made, over the life of the plan and that these would result in the development of satellite fields, each 10 acres in area (8,000 – 12,000 cubic yards per acre). These developments would be located within 25 miles of the main pad/CPF with construction occurring one at a time, but within the life of the plan. A paced development would reduce socio-cultural impacts to the western Arctic Slope, spread the work out over a longer period of time and provide a longer window of opportunity for the local work force. The discovery of each satellite field is assumed to require three exploration wells and two delineation wells, and contain 10 production wells and 7 injection wells. Each field would have a production life of 10 years. No permanent camp facilities would be required for development of the satellite fields. The main pad/CPF would be upgraded to accommodate the increase in workers necessary to operate the additional satellites. However, temporary camps would be used during construction.

E. PROJECTION OF COAL BED NATURAL GASE DEVELOPMENT

Coalbed natural gas exploration in the KSPPA would likely occur through an ongoing joint State/Federal program to assess the coal bed natural gas resource potential of Alaska. The program will also determine the feasibility of developing this resource for the benefit of rural communities in the state. The western Colville basin near Wainwright has been identified as one of three highly prospective CBNG coal basins (Clough, 2001). Many rural communities in Alaska depend on diesel fuel as a source of energy for heating and for the generation of electricity. Fuel must be barged or flown in to the more remote locations. If coal bed methane was available close to a rural community, it could offer an alternative energy source.

A small coalbed gas field in a remote area, sub-commercial by industry standards, could represent a viable, long-term energy resource for a small village or major mine site such as the Red Dog zinc mine. The costs of exploration, development and production of coalbed gas must compare favorably to the existing cost of supporting the current diesel fuel-based system. Proximity of the gas to rural customers is also a critical component. The Wainwright site holds the potential for thick beds of coal below the village so that shallow drill holes would intersect the thickest section of coal possible at an appropriate depth for gas production. This positioning would reduce drilling costs as well as costs of building a pipeline to the nearby village A medium-sized community of 700 people, for example, uses about 250,000 gallons diesel fuel per year, roughly half for electricity and half for home heating. This translates to about 34.5 million cubic feet of gas per year, with a 30-year supply requiring resources of about 1 billion cubic feet.

It is assumed under this scenario that a discovery is made in the Kukpowruk coal basin near the village of Point Lay (pop 250) in the northwest section of the KSPPA. The economic viability, however, of the Kukpowruk coal basin's CBNG resources is highly uncertain because sufficient data on gas and water productivity does not yet exist. Under this RFD scenario for coalbed natural gas production through 2020, recoverable reserves are assumed to be 0.5 billion cubic feet (Bcf) and accessible from multiple coal seams. This would supply a population of about 250 with sufficient gas for 30 years. The number of wells is dependent upon several variables including: number, thickness and depth of coal seams; net coal thickness; access; amount of gas that could be recovered; permeability and porosity; produced water management; the number of CBNG wells that can be served by a disposal well and; disposal well depth. This development scenario would require a total of 12 wells; 10 producing wells, 1 monitoring well and 1 water reinjection well.

Coal bed natural gas development generally involves a larger amount of surface disturbance than conventional oil and gas development due to the dispersed nature of CBNG well development. Typical CBNG wells require a network of access roads, drilling sites, pipelines, power lines, compressor stations, and containment ponds. Roads and utility corridors would be positioned to use existing disturbances as much as possible. Existing roads would be used as often as possible, and the gas field would be designed so that as many wells as possible can be serviced from each road. Roads to wells and compressor sites would be limited to single lane width with turnouts. Exploration wells would not have permanent gravel access roads. The operator would co-locate electric power, gas and water lines with proposed roads when feasible to minimize overall disturbance. Power lines would be aboveground or buried per operator's plans. Under this scenario, it is assumed that the field is located close to an existing fuel distribution point near the village and much of the disturbance associated with a commercial venture would no be realized.

Wells would be drilled with truck mounted water well type rigs capable of setting up on uneven terrain. Air is used to drill and remove the cuttings, instead of fluid, to reduce the volume of wastes to be buried on the well pad or hauled off site. A 100' square area would be bladed to accommodate the rig and a small reserve pit (6' x 15' x 15'). CBNG production could occur simultaneously from multiple seams or staggered over time from separate seams. During the early development phase, wells would be about 800 feet deep and designed to penetrate the local permafrost. Over time well depths would increase to more than 1,000 feet deep with a maximum depth of about 4,000 feet. Each pad would require about 1.75 acres; 1 acre for the pad (190' by 240') and 0.75 acres for the access road. Part of the well pad area would be reclaimed for production operations and the entire area would be reclaimed when the well is plugged and abandoned. The long-term surface disturbance (10 to 20 years) at each productive well location where cut and fill construction techniques are used would encompass approximately 0.005 acres.

Wells would be completed using 7" steel well casing set and cemented to the surface from the top of the target coal bed. Small diameter tubing and an electric submersible pump would be installed in the well to bring the water to the surface. Once all wells have been drilled, produced water would be gathered and transported to the injection well for disposal. Wells determined to be productive would be shut-in until a production facility is constructed. If the well is determined not to be productive, it will be properly abandoned.

The average well discharge rate for a typical coalbed natural gas well is about 400 to 500 barrels of water per day. It is assumed the amount of water produced would not be the same for every well, and that water production would drop off rapidly over time, as the pressure within the coal seam falls and gas begins to flow freely. The early phases of high water production and low gas recovery would last for a period of six months to three years (Ogbe, 2000). The produced water would be collected in a buried two-inch polyethylene flow line for transport to the water disposal well (200’ x 200’ each). The pipeline trenches for well gathering lines are expected to disturb portions of 20 to 30-foot wide corridors temporarily and to be reclaimed as soon as practical after construction is completed. Trenches would be constructed along the access roads where possible. Separate gathering lines would be buried in the trenches and would transport methane gas to a field compressor and produced water to disposal well.

The water disposal well pad would consist of one 100 bbl water tank, a pump house, piping, and a well house. Those areas where elevation differences require supplemental pumping to transfer the produced water, transfer pumping stations (120’ by 120’ pads), consisting of a 400 bbl water tank with associated pump and piping, may also be needed. Water in the tank would be separated from the gas and injected into subsurface aquifers geologically isolated from potential underground sources of drinking water. Disposal rates would be dependant on formation characteristics of the injection zones and in this scenario it is assumed that one injection well would service the 10 CBNG wells.

Unlike conventional natural gas, CBNG has not generally required special treatment before sale - the gas is merely put through a dehydrator to remove remaining water and then injected into a pipeline. However, impurities would be removed before the gas is sent the production facility. Treatment depends on the nature of the produced gas -- which is yet to be determined.

Produced natural gas (methane) under wellhead pressure would move through the low pressure gas gathering system to a field compressor station (0.5 acres). Under this RFD scenario the gas gathering system would consist of 1 field compressor designed to raise the pressure from about 30 psi to 150 psi. A 0.75 mile gathering line (approximately 25 feet wide), consisting of polyethylene flowlines (one per well) would be buried from each pad to the field compressor. These lines would be laid in the travel routes to the wells and would follow the roads to the field compressor. The gas from each well is metered at the field compressor and commingled prior to being piped a distribution point near the village.

Well heads and metering equipment would be housed in 5 foot high fiberglass well covers painted an unobtrusive color and fenced to protect the facility from damage by wildlife. Electronic flow devices will measure natural gas production and water will be measured through ultrasonic flow meters; a panel installed at the well starts and stops the pump based on fluid level measurement.

IX. SURFACE DISTURBANCE DUE TO OIL AND GAS ACTIVITY ON ALL LANDS

Type of Action	Number of Actions	Area Disturbed[1]	Short Term Disturbance (acres)	Long Term Disturbance (acres)
2-D Seismic Surveys (line miles)	*600 to 3,200*	*Winter months only (1 acre/mile)*	*600[2] to 3,200[2]*	*Minimal*
3-D Seismic Surveys (acres)	*130*	*Winter months only*	*130*	*Minimal*
Exploration and Development Staging areas	5	Gravel pads	174[3]	174
Oil Exploration Wells	43 to 55	Ice pads, ice roads and low impact vehicle trails	1,352[4] to 1,730	0[5]
Gas Exploration Wells	0	Ice pads, ice roads and low impact vehicle trails	0	0
Coalbed natural Gas (CBNG) Gas Wells	11	10 drill pads, access road, 1 monitoring well	20[6]	15[7]
Delineation gas wells (offsetting exploration wells)	0	Ice pads, ice roads and low impact vehicle trails	0	0
Gas development wells	0	Drill pads, access road, pipelines and utilities	0	0
Delineation oil wells (offsetting exploration wells)	23	Ice pads, ice roads and low impact vehicle trails	330[8]	0
Oil development wells	182	Gravel drill pads (1 main pad/CPF, 5 satellite pads), airstrip, gravel access roads and 3 gravel sources	417[9]	417
Three-phase produced fluids (oil, gas, water) gathering lines (miles)	36	3 to 12 inch diameter pipelines and utilities (gravel access road is accounted for under Oil Development Wells)	327[10]	4
CBNG Field Compressor Station	1	Pad, access road, gathering pipelines and utilities	23.5[11]	23.5

CBNG Water Disposal Facility	1	Pad, access road, pipelines and utilities	10[12]	10
Oil transmission pipeline (miles)	350	2 pump stations with heater stations and emergency staging areas for each, ice road and pipeline VSMs	4,322[13]	114
Total Acres Disturbed by Exploratory Drilling, Development and Production.			**6,975.5 to 7,353.5**	**757.5**

NOTES:

1. Acreage estimates for each component from observed disturbance in NPR-A and Alpine field unless otherwise noted.

2. Seismic exploration (italicized) is not included in the total acres disturbed because it is temporary and minimally intrusive on the environment. Geophysical exploration requires a discretionary approval that is not associated with leasing and subsequent activities. Alpine field (600 miles/4 yrs. = 150 miles/yr; 150/3.75 = 40 miles/year or 150 miles every 4 yrs.); NPR-A (21,000 miles/28 yrs. = 750 miles/yr; 15 yrs. life of plan /750 miles/yr. x 0.27 = 3,037 total miles over life of plan; 3,037/15 yrs. = 202 miles/yr or about 800 miles every 4 yrs.).

3. Exploration and Development Staging areas: Assume 4 gravel staging areas x 6 acres each for exploration support + one 150 acre staging area for oil field development support = 174 acres.

4. Oil exploration wells: Assume 43 to 55 wells @ 6 acres each for ice pad (including worker camp) and 6 miles of roads per well by 35 ft. width; (43 wells x 6 acres) + (6 mi x 5,280 x 35 ft) = 258 + 1,094 = 1,352 acres; (55 wells x 6 acres) +(6 mi x 5,280 x 35 ft) = 330 + 1,399 = 1,730 acres)

5. All exploration well pad acreage is reclaimed within one season, excluding 6 discovery wells which are developed into production wells (discovery well acreage accounted for in oil development well acreage). It is assumed that all ice roads are reclaimed within one season.

6. Assume 11 CBNG wells; 1 acre per pad = 11 acres + (5 miles of access roads (0.75 miles per pad x 11 pads) x 15 ft. width)) = 9 acres. Total = 20 acres.

7. Assume 25% of disturbed acreage reclaimed after production starts = 5 acres reclaimed.

8. Delineation oil wells - assume 6 acres per ice pad; 2 mile access ice road per delineation well by 35 ft. width by 23 wells = 330 acres. It is assumed that all access ice roads and pads are reclaimed within one season.

9. Development oil wells - Assume 1 new oil field; 6 gravel pads (one 90-acre main pad/CPF, one 10-acre satellite field followed by the discovery of 4 additional 10-acre satellite fields); each satellite field required 3 exploration wells and 2 delineations wells; Main pad/CPF and initial satellite pad contain 114 injection/productions wells; remaining 4 satellite pads each contain 17 injection/productions wells; (90 acres + 50 acres = 140 acres) + (3 gravel sources x 35 acres) + (35 miles access roads x 5,280 x 35 ft wide) + 5,280 ft airstrip x 200 ft wide) = 417 acres.

10. Three-phase gathering pipelines - (75 ft wide right-of-way corridor x 5,280 x 36 miles = 327 acres); reclaimed to (20 ft. between parallel VSMs x 2 ft. drill hole for VSM x 3,801 VSMs = 4 acres long-term disturbance).

11. CBNG field compressor station (0.5 acres); assume 0.75 miles of plastic low-pressure gathering lines per pad (10 pads) by 25 ft. utility width (parallels pad access road) = 23 acres; 23 acres + 0.5 acres = 23.5 acres.

12. CBNG water disposal facility - 1.0 acre pad; assume 0.75 miles of plastic water gathering lines per pad (10 pads) by 25 ft. utility width (parallels pad access roads) = 9 acres; 1 acre + 9 acres = 10 acres.

13. Oil transmission pipeline - (100 ft wide right-of-way corridor x 5,280 x 350 miles = 4,242 acres) + (2 pump stations x 40 acres = 80 acres) = 4,322 acres; reclaimed to (20 ft. between parallel VSMs x 2 ft. drill hole for VSM x 36,960 VSMs = 34 acres) + (80 acres) = 114 acres long-term disturbance.

A. TYPICAL EXPLORATION, DEVELOPEMNT, PRODUCTION AND ABANDONMENT

To fully evaluate the surface disturbance impacts associated with projected oil and natural gas exploration and development in the KSPPA, the activities typical of these actions as they apply to north western Alaska are discussed below. Table 6 shows typical Alaska oil and gas activities and timeframes.

1. Geophysical Exploration

The likelihood of the presence of oil and gas is often determined by geological prospecting. Such prospecting can be done on the ground, where on and off-road vehicle travel may be necessary, or by aerial survey. Exploration activities may include examination of the surface geology, geophysical survey programs, researching data from existing wells, and/or drilling an exploratory well. Surface analysis includes the study of surface topography or the natural surface features of the area, near-surface structures revealed by examining and mapping exposed bedrock, and geographic features such as hills, mountains, and valleys. Subsurface geology is not always accurately indicated by surface outcroppings. To verify surface indicators and to map the subsurface structures, geophysical exploration is used. An oil and gas lease is not required for geophysical exploration to occur; it may be permitted prior to or subsequent to leasing by bonded geophysical operators. Exploration activities may occur across the same area many times and continue over a period of years.

Geophysical companies usually conduct seismic surveys under contract with license holders. Contracts may have provisions that allow the geophysical company to sell the data to other interested companies. If sufficient data are already available, additional on-the-ground seismic data acquisition may not be necessary.

Geophysical exploration activities on federal lands in Alaska are regulated by 43 CFR 3151.2. The BLM issues permits which include terms and conditions deemed necessary to protect values, mineral resources and nonmineral resources including specific mitigating measures for public safety warnings, wildlife concerns, property protection (fences, wells, buried utility lines, etc.), and site reclamation. Restrictions on geophysical exploration permits depend on the duration, location, and intensity of the project.

Geophysical surveys help reveal what the subsurface geology may look like. There are three types of geophysical exploration: 1) gravitational field, 2) magnetic field, and 3) seismic characteristics. Gravitational prospecting detects variations in gravitational attraction caused by the differences in the density of various types of rock. Magnetic field methods reveal buried structures (likely to yield oil and gas) because such structures show a strong magnetic response. Magnetic prospecting often replaces or is used to supplement gravitational work. Both surveys consist of taking readings at regular intervals across the land from either hand held instruments, ground vehicles, or aircraft. No actual surface disturbance is involved unless off-road vehicle travel is used to reach survey points. These methods are used to get subsurface information over a large area.

Seismic prospecting gives the most reliable and reproducible results. Companies will either gather two-dimensional (2-D) or three-dimensional (3-D) seismic data.

Two-dimensional seismic programs usually require fewer personnel and use less equipment than 3-D programs. Generally, geophysical seismic lines are run on wide spacing intervals and are narrowed and concentrated in smaller geographic areas as the target area is better defined. Three-dimensional surveys tend to be used to delineate prospective areas rather than as exploratory tools in frontier areas due primarily to the higher costs involved. With a strong move towards 3-D surveys, 2-D has almost become a thing of the past. However, this is not the case in Alaska. Large areas that have been relatively unexplored such as north western Alaska can be mapped by acquiring large regional grids of 2-D seismic data which provide exploration teams with the information necessary to evaluate the regional geology and the potential hydrocarbon traps (Rice, 1997).

Land-based seismic surveys are typically conducted during the winter months using truck-mounted vibrators or helicopters for remote operations. The method involves sending energy into the earth using an explosive charge or other energy wave-generating device, such as Vibroseis. Vibroseis generates energy waves of continuously varying frequency using metal plates lowered to the ground from beneath each vehicle. With the entire weight of the truck resting on the plate, a hydraulic system vibrates the plate which transfers the energy into the ground. Depending on rock density, waves bounce back from the various formation layers and are received by listening devices called geophones arrayed along the line of survey. From two to eight trucks are used in tandem. Unless the topography is relatively flat and open, the trucks are restricted to existing roads and trails. An instrument truck equipped with a seismograph records the seismic information on a computer which is subsequently processed and displayed in the form of a seismic reflection profile. The Vibroseis technique works best on a hard surface, as a spongy surface does not transmit the output energy very well.

Explosives, although rarely used, are another way to impart energy into the ground for the seismograph to record. The explosives are lowered into drill holes and detonated, or they may be suspended on stakes above the ground to eliminate the need for drilling holes. The drill holes are drilled with either track-mounted drills or
Explosives, although rarely used, are another way to impart energy into the ground for the seismograph to record. The explosives are lowered into drill holes and detonated, or they may be suspended on stakes above the ground to eliminate the need for drilling holes. The drill holes are drilled with either track-mounted drills or
with drills slung into position by helicopters.

Project Phase	Duration (years)	Activities
Exploration	1 to 5	• geophysical permitting • environmental studies • seismic surveys to define prospects • well-site surveys and permitting • construct access roads/trails (ice) • temporary ice pads • exploratory drilling • drill delineation wells (after discovery) • land clearing • work camp • water usage • increased air traffic • appraise and engineer reservoirs • drilling muds & discharges
Development	3 to 6	• permitting • identify gravel pits • construct gravel pads, and roads • dock & bridge construction • install drilling rigs • install pipelines • construct base camp • environmental monitoring • drill development wells • vehicle traffic to and from pads • drill re-injection wells • install production facilities and hookup
Production	10 to 30	• well workover (rigs) • pipeline maintenance • gravel pads and roads • produced water • air emissions • work camps • trucking
Abandonment	2 to 5 years per well	• plug and abandon wells • remove production equipment • dismantle facilities • decommission pipeline • restore and re-vegetate sites • phase out environmental monitoring

Table 6—Typical Oil and Gas Activities and Timeframe.

For 3-D seismic operations, 4-inch diameter holes are drilled typically 25 feet deep with 5 pounds of explosive set at the base of the hole. Surface charge seismic involves placing explosive charges on the ground or above ground attached to wooden stakes some three feet high. In difficult terrain, both explosive methods may be used via helicopter to ferry people, materials, and instruments to the detonation points along the lines of survey. This eliminates surface impacts

2. Exploratory Drilling

If geologic studies indicate that oil or gas may be present, lessees (an entity that owns the lease) may initiate drilling of an exploration well. Drilling is the only way to assess whether commercial quantities of oil or gas are present in subsurface rock formations. Drilling wells is expensive and exploratory drilling happens only after mineral rights have been secured, and after preliminary, less expensive exploration activities, such as seismic surveys, reveal the most likely places to find oil or gas. Exploratory drilling operations normally occur in winter to minimize impact. Temporary 35-foot wide ice roads are built to the area and are constructed by spreading water from local sources along the proposed route (lakes and rivers) to build up a base designed to be a minimum of 6 inches thick. Each mile of road requires about 1.0 to 1.5 million gallons of water. Aggregate chips produced from frozen lakes are used to reduce construction time and water requirements. Routes over rivers and lakes are constructed using the same methods. The length of an ice road is dependent upon the well site location in relation to existing gravel roads.

The drill site is selected to provide access to the prospect to be drilled and, if possible, is located to minimize the surface area required. A typical drill pad has dimensions of about 512 feet by 512 feet (6 acres) and is constructed of ice designed to be a minimum of 1 foot thick. About 500,000 gallons of water are required to construct a typical ice pad. The pad supports the drill rig, which is brought in and assembled at the site, a fuel storage area, and a camp for workers. If possible, an operator will use nearby existing facilities for housing and feeding its crew. If the facilities are not available, a temporary camp of trailers may be placed on the pad. Enough fuel is stored on-site to satisfy the operation's short term need, which amounts to about 4,500 gallons of diesel and gasoline per day. The storage area is a diked gravel pad lined with an 80-mil synthetic membrane. Additional amounts of fuel may be stored at the nearest existing facility for transport to the drilling area as needed.

Byproducts of drilling activities include muds and cuttings, produced water and associated wastes. Drilling employs the use of carefully mixed fluids, called muds. Cuttings are small fragments of rock up to an inch across that are dislodged and carried to the surface by drill muds. Drilling muds are maintained at a specific weight and viscosity and are mostly water-based mixtures of clay (bentonite) and other earthen materials designed to be environmentally benign. The muds are used to cool and lubricate the drilling bit, facilitate the drilling action, clean the bottom of the hole, flush out cuttings within the well bore, seal off porous zones in down-hole formations to prevent the flow of drilling fluids into these formations, and maintain reservoir pressure. Drilling mud is circulated through the drill pipe to the bottom of the hole, through the bit, up the bore of the well, and finally to the surface. When the mud emerges from the hole, it goes through a series of equipment used to screen and remove rock chips and sand-size solids. When the solids have been removed, the mud is placed into holding tanks and from the tanks it is pumped back into the well.

Chemicals may be added to maximize the effectiveness of drilling and casing. Oil-based muds and synthetic-based muds may also be used depending on the well depth, well diameter, and subsurface formations.

An exploratory drilling operation using water-based muds generates 7,000 to 13,000 barrels of waste per well, and depending on the depth and diameter of the well, 1,400 to 2,800 of those are cuttings (1993 EPA report). Oil-based mud volumes are generally less than water-based, because they are more efficient and oil-based muds may be reconditioned, reused, and re-sold. Newer synthetic-based muds produce less waste, improve drilling efficiency, are reusable, and have advantages in environmental protection over oil or water-based muds (Veil, J.A. and others, 1999).

The BLM (as well as the State) discourages the use of reserve pits and most operators now store drilling solids and fluids in tanks or in temporary on-pad storage areas until they can be hauled out or injected down the annulus of the well in accordance with State of Alaska statute. A permit is required by the State for onsite disposal or storage of drill cuttings. Injection of ground up drill cuttings requires approval from AOGCC

Drilling mud and fluids produced from the well are separated and disposed of, often by reinjection at another facility. With appropriate permits, solids may be left in place in a capped reserved pit. If necessary, a flare pit may be constructed off of the drill pad to allow for the safe venting of natural gas that may be encountered in the well. Exploratory drilling is conducted 24 hours a day because of rig-time costs. There are three 8-hour or two 12-hour shifts a day.

The actual time to drill a well depends on several factors including the depth of the hole, the number and degree of mechanical problems, and whether it is a dry hole or a producer. One of the primary objectives of drilling an exploration well is the acquisition of downhole information. Formation evaluation covers a variety of data gathering and retrieving methods that include mud logging, wireline logging, formation testing, coring, and measurement while drilling (MWD) surveys. In wildcat wells (wells drilled outside of areas of established production or into deeper untested zones in established fields), it is important that quality data be obtained in order to justify the costly decision to run (or not run) production casing and complete the well.

Mud logging, conducted while the well is being drilled, evaluates the mud circulating back to the surface for the presence of hydrocarbons. Drilling will liberate even small amounts of hydrocarbons from sedimentary rock. The mud log is also used to record and describe the rocks that are encountered in the well.

Wireline logs provide indirect measurements of rock properties and are created by lowering instruments (the logging tool) into the well. They also are used to precisely determine the elevation and thickness of individual rock units or identify potential producing zones.

Formation testing (drill stem test or DST) involves temporary completion of a well and measures the flow of hydrocarbons to determine whether or not commercial quantities exist in the formation being evaluated.

Coring obtains a whole sample of the subsurface rock by placing a special bit and core barrel at the end of the drill string and drilling a cylindrical sample of the rock. Core barrels are commonly 30 to 60 feet in length and are sent to a laboratory where it can be analyzed for certain properties such as porosity (space in the rock that is filled by fluids), permeability (the ability of the rock to transmit fluids), and the ratio of fluids present in the pores of the rock (oil, gas, and water).

The drilling process is as follows:

- Steel conductor casing, is set 60 feet into the ground.
- The bit rotates on the drill pipe to drill a hole through the subsurface rock formations.
- Blowout preventers are installed on the surface casing and only removed when the well is plugged and abandoned. Blowout preventers are large, high-strength valves that close hydraulically on the drill pipe to prevent the escape of fluids to the surface or into groundwater formations.
- Progressively smaller sizes of steel pipe, called casing, are placed into the hole and cemented in place to keep the hole from caving in, to seal off rock formations, and to provide a conduit from the bottom of the hole to the drilling rig.
- The well produces hydrocarbons, is shut-in, or is plugged and abandoned.

Upon completion of the drilling, the equipment is removed to another location. If hydrocarbons are not discovered in commercial quantities, the well is called a “dry hole.” The operator is then required to follow state and BLM policy procedures for plugging a dry hole. The drill site and access roads are rehabilitated in accordance with the stipulations attached to the approval of the well. If the exploratory well is successful, the operator will probably drill one or two more wells to delineate the extent of the discovery and gather more information about the field. The lessee needs to know how much oil and gas may be present, their quality, and the quality of the rocks in which they are found.

3. Development and Production

After the discovery of a successful well, additional exploratory wells may be needed for industry to make a decision on whether to develop the field. These additional wells can also provide meaningful information for land managers to help analyze potential impacts of field development and to make decisions based on more accurate information. Industry's decision to develop the field is essentially an economic one and may depend on the type of hydrocarbon present (i.e., oil or gas), the size and productivity of the geologic structure and formation, the distance from infrastructure, the price of oil or gas, and marketability. In some cases, a discovery may not be fully developed although production may take place to recoup some of the costs of exploration.

Once the presence of a reservoir is confirmed, the lessee may decide to pursue development of the field to fully extract the resource. The procedures for drilling development wells are about the same as for exploratory drilling except that there is less subsurface sampling, testing and evaluation. Field development locations are surveyed and a well spacing pattern established by the State with the concurrence of the BLM on federal leases. The spacing between wells depends on the State's regulations and the type of hydrocarbon sought. Gas wells are usually spaced one per 640 acres and oil wells often 160 acres or 320 acres. In developed petroleum fields, there are about two miles of roads per 160 acres.

Many fields go through several development stages. A field may be considered fully developed and produce for several years and then new producing zones may be found. If commercial hydrocarbons are discovered in a new producing zone (reservoir) in an existing field, it is called a new pool discovery, as distinguished from a new field discovery. New pools can either be deeper or shallower that the existing producing zone and may lead to the drilling of additional wells. When sufficient development wells are completed, the production phase begins. Production allows the lessee to receive a return on investment through extraction, collection, and transportation of the resource to the marketplace. Depending upon reservoir characteristics, which affect the flow of oil and gas to the wellhead, additional development wells are drilled to extract the oil and gas.

After planning and designing the facility layout, the operator constructs gravel pads and drills production wells. To the extent permitted by the geologic target, the locations selected for well sites, tank batteries, pits, and pumping stations are planned so as to minimize long-term disruption of the surface resources. Design and construction techniques and other practices are employed to minimize surface disturbance and effects on other resources, and maintain the reclamation potential of the site. Site-specific geotechnical studies are conducted prior to any development activities to assess the local permafrost conditions. Structures, such as drill rigs and permanent facility buildings, are insulated to prevent heat loss into the ground.

A level drill pad, generally 3 to 9 acres in size, is needed to set up and operate the rig. Usually, the dimensions of a pad measure 350 feet by 450 feet, but this may be modified based on the number of wells to be drilled, the natural contours of the land and the other resource values involved. All of the pad must be placed on a "cut" rather than "fill" surface for reasons of safety and rig stability. Once the rig is set up, drilling takes place 24-hours per day, seven days a week. For all surface-disturbing activities, the topsoil is removed and stockpiled for redistribution over the disturbed area prior to reseeding of the site. Restoration of the area normally includes reseeding the area with native species, recontouring and drainage control.

Approximately 30 personnel are needed in drilling a typical well. Drilling may take from 2 weeks to 6 months to complete depending on the depth to be drilled. If no economic quantities of gas or oil are found it is considered a dry hole and the facilities are removed and the well pad is reclaimed along with the access road, unless it is needed for other purposes.

Firewalls/containment dikes are to be constructed and maintained around all storage facilities/ batteries. The containment structure must have sufficient volume to contain, at a minimum, the entire content of the largest tank within the facility/battery.

During drilling and after a well is in production, water comes to the surface mixed with oil and gas, and must be separated before further refining. Produced water contains mostly natural substances such as clay and sand, which is mixed with oil, water and gas, found in the subterranean strata. Produced waters are usually saline with some level of hydrocarbons. Associated wastes are other production fluids, such as tank bottom sludges, well work-overs, gas dehydration processes, tank wastewater and other residues which are considered non-hazardous (low-toxicity) by the EPA. Like drilling muds, chemicals may be added to produced water to remove harmful bacteria, halt corrosion, break up solids, prevent scale build up, and break oil/water emulsions.

Approximately 10,000 to 35,000 gallons of water a day may be needed for mixing drilling mud, cleaning equipment, and cooling engines. Water sources may be from wells, lakes or streams. Drilling depths may range between 2,000 feet and 15,000 feet. Transporting and setting up a drill rig capable of reaching the deepest zones requires an access road sufficient to handle the 30 to 40 semi-trucks and trailers of heavy equipment and a daily traffic of 20 to 30 vehicles. These are low volume, single-lane roads, which may be reclaimed after a particular use terminates. These roads normally have a 35 foot travelway and connect terminal facilities, such as a well site, to collector, local, arterial, or other higher class roads.

Once production is established, pipelines and/or flow lines are constructed in conjunction with the construction of access roads whenever possible to minimize additional disturbance. Pipeline rights-of-way are generally less than 100 feet in width and follow existing rights-of-way where possible. Pipelines are trenched, backfilled, insulated (if buried), or elevated to permit movement of wildlife and to prevent undesirable thawing of permafrost. Pipelines are an economically feasible way to transport oil and gas onshore. Oil transportation by truck is sometimes used, but in many cases, is not economically feasible because of the low quantities of oil that can be transported and high labor costs. Production from multiple wells on one lease may be carried by flowlines to a central processing facility. Central processing and storage facilities can be used for multiple wells on the same contiguous lease or multiple wells in an established unit.

Production and processing equipment at a typical gas well location might consist of a wellhead, a production separator, a dehydrator, and tanks. The wellhead (or christmas tree) has valves used to control the flow of gas and liquids from the well. The gas must be separated from liquids in the production stream (water, gas condensates, or light crude oil) and is diverted to processing equipment on the location. During processing, a production separator removes most of the water and liquid hydrocarbons and a dehydrator removes any remaining water in the gas. The gas then goes through a metering facility and into a sales or gathering pipeline. All hydrocarbon liquids are placed into small (< 400 barrel tanks;1 barrel equals 42 gallons) and subsequently trucked from the well site and sold or placed into a pipeline.

In order to move the gas through the pipelines gathering system, compression equipment is used. Field compression units are small and mobile and are sized for the amount of gas that needs to be moved. Gas from the field gathering lines may undergo further processing to remove hydrocarbon condensates and water to ensure the gas meets stringent transportation pipeline specifications. It is then fed into larger transportation lines, often at compressor stations along the route.

Natural gas, in many instances, needs more than simple well site processing due to impurities (e.g., hydrogen sulfide) or large amounts of non-flammable gases such as carbon dioxide. This separation process, which involves large volumes of gas from multiple wells, is conducted at facilities called gas plants. Sometimes the gas contains valuable heavier hydrocarbon compounds such as natural gas liquids or NGLs that must also be processed out of the methane.

Production operations for natural gas generally include the following:

- Natural gas flows through a high-pressure separator system where liquids (water, condensate, etc.) are removed. Produced oil goes through a separator to remove the natural gas.
- The gas is compressed if necessary.
- The gas is dehydrated to remove any remaining water.
- The gas is metered (i.e., the amount of gas produced is measured).
- The gas is transported to a facility where it passes through a water precipitator to remove oil.

Typical oil well locations consist of a wellhead, pumping equipment, phase separation equipment, storage tanks and a central processing facility (for multiple wells on the same lease or unit). Oil wells can be completed as flowing wells or pumping wells. Flowing wells have sufficient formation pressure to raise the oil to the surface. Insufficient formation pressure requires the oil to be pumped to the surface via: 1) pump jacks powered by internal combustion engines or electric motors, 2) submersible pumps, when large volumes of fluid have to be produced such as wells containing large amounts of water with the oil. 3) artificial lift or gas lift, where natural gas is pumped into a well to lift the fluids to the surface, or 4) hydraulic pumps where crude oil is pumped down one tubing string, activating a hydraulic piston and well fluids before returning to the surface in a second string or the casing annulus.

When the fluids reach the surface, the oil must be separated from the water and gas though the use of appropriate separation equipment. Large amounts of water are gravity-separated from the oil and routed into tanks for disposal. The remaining fluid is fed into heater-treaters, which separate the gas from the oil and also break apart water-in-oil emulsions that may occur during the production process. The casinghead gas, depending on the quantities produced, can be used on the lease, recovered and placed into pipelines for sale, or vented. After the separation process, oil and water are stored in tanks either at the location or at central processing facilities. The tanks can generally hold 400 to 500 barrels and any given tank battery will have varying numbers of tanks depending upon the productive capacity of the well. Tanks and separation vessels are placed within earthen berms or other containment structures in order to contain spilled fluids in case of an upset condition or rupture of a tank or vessel. Production equipment are required to be painted in colors that will blend into the surrounding environment. Popular colors are brown and green. Some or all of the facility must be fenced.

Production operations for oil generally consist of the following:

- Produced crude oil goes through a separator to remove gas from the oil stream
- The oil moves to processing facility via a pipeline.
- The gas removed from the oil may be compressed and reinjected to maintain the pressure in the producing formation and assist in oil production.

As more wells are placed in production, roads are improved by regular maintenance, surfacing with gravel and installing culverts. Mineral materials (e.g., sand and gravel) are usually purchased from local contractors and obtained from federal sources. Materials that are obtained from areas of federally owned minerals require a sales contract and are processed through the field office where the materials occur. A new stage of field development can lead to changes in locations of roads and facilities. All new construction, reconstruction, or alterations of existing facilities-including roads, pits, flowlines, pipelines, tank batteries, or other production facilities must be approved by the BLM.

If sufficient natural gas reserves are discovered and it is economically feasible, the gas could be made available to local communities through new pipelines. Gas may also be re-injected, as is done on the North Slope.

A pipeline may be built above ground or underground. Above ground pipelines require a minimum clearance (usually 5 feet) to permit animal migration/travel. When buried, pipeline depth must be at least 48 inches. When possible, a common point of collection shall be established to minimize the number of production sites.

The development "footprint" in terms of habitat loss or gravel filling has decreased in size in recent years as advances in drilling technology have led to smaller, more consolidated pad sizes. Longer horizontal departures reduce per acre impacts compared to older field developments. Depending on the depth of the reservoir rock and horizontal deviation ability, the area of surface disturbance per acre of habitat can be minimized. A single production pad and several directionally drilled wells can develop more than one, and possibly several, 640-acre sections. Based on current development practices, surface impact from developing tracts is unlikely to exceed 2 percent per 640-acre section for any given development on leased and developed acreage.

4. Plugging and Abandonment of Wells

If the well is a dry hole, the site is recontoured and the topsoil is spread over the disturbed area followed by seeding with native plants and grasses. If the well is a producer, that portion of the original pad needed to continue operations will remain unreclaimed for the life of the well (10 to 20 years).

The purpose of plugging and abandoning (P&A) a well is to prevent fluid migration between zones, to protect minerals from damage, and to restore the surface area. Each well has to be handled individually due to a combination of factors, including geology, well design limitations, and specific rehabilitation concerns. Therefore, only minimum requirements can be established initially, then modified for the individual well.

The first step in the P&A process is the filing of the Notice of Intent to Abandon (NIA). Both the Surface Management Agency (SMA) and the BLM will review this. The NIA must be filed and approved prior to plugging a past producing well. Verbal plugging instructions can be given for plugging current drilling operations, but an NIA must be filed after the work is completed. If usable fresh water was encountered while the well was being drilled, the SMA will be allowed, if interested, to assume future responsibility for the well and the operator will be reimbursed for the attendant costs.

The operator's plan for plugging the hole is reviewed. The minimum requirements are as follows: In open hole situations, cement plugs must extend at least 50 feet above and below zones with fluid which has the potential to migrate, zones of lost circulation (this type of zone may require an alternate method to isolate), and zones of potentially valuable minerals. Thick zones may be isolated using 100-foot plugs across the top and bottom of the zone. In the absence of productive zones and minerals, long sections of open hole may be plugged with 150-foot plugs placed every 2,500 feet. In cased holes, cement plugs must be placed opposite perforations and extending 50 feet above and below except where limited by plug back depth.

A permanent abandonment marker is required on all wells unless otherwise requested by the SMA. This marker pipe is usually at least 4 inches in diameter, 10 feet long, 4 feet above the ground, and embedded in cement. The pipe must be capped with the well identity and location permanently inscribed.

The SMA is responsible for establishing and approving methods for surface rehabilitation and determining when this rehabilitation has been satisfactorily accomplished. Possibilities may exist for developing a well for fresh water purposes, utilizing improvements, or making wildlife habitat improvements. Reclamation criteria include: 1) Final configuration of the disturbed area, 2) Stabilization of the soil, 3) Management of the topsoil and addition of appropriate fertilizers, 4) Revegetation with prescribed seed mixtures, 5) Air, water, and visual quality standards, 6) Compliance inspection intervals and bond amounts, 6) Conditions for bond release.   At this point, a Subsequent Report of Abandonment can be approved.

5. Coal Bed Methane Development

Drilling for CBNG is very similar to drilling for conventional oil and gas except that generally smaller drilling rigs are used since, at present, CBNG resources are generally at much shallower depths on average than oil and gas. Coal bed methane development also involves a larger amount of surface disturbance than conventional oil and gas development. CBNG ancillary facilities include access roads, pipelines for gathering gas and produced water, electrical utilities, facilities for treating and compressing gas and disposing of produced water, and pipelines for delivering gas under high pressure to transmission pipelines.

Unlike conventional gas, CBNG does not usually require additional treatment or processing before use. The gas is piped from the wellhead to a commercial gas line for direct distribution to homes and businesses. Typical surface disturbance associated with a producing coal bed methane pad is around 1 acre (Coal Bed Methane Primer, 2004). Surface disturbance would also include construction of off channel water storage, battery sites of about 2 acres each, one high-pressure compressor site of approximately 10 acres, and access roads (0.75 acres per pad), pipelines, and electric lines needed to service the wells.

Wells to be drilled on shared sites with up to four wells (one per coal bed) may be located on a common well site. The operator should co-locate electric power, gas and water lines with proposed roads as much as possible to minimize overall disturbance. Coal bed methane production produces large volumes of water of varying quality for which two disposal methods exist: surface disbursal or re-injection. Average well discharge for a typical coal bed methane well is around 12 gallons per minute, or just over 17,000 gallons/day.

Wells are drilled with truck mounted water well type rigs; because this type of rig can be set up on uneven terrain, the surface is generally not bladed or a pad site constructed unless topography requires it. The drilling and completion operation for a CBNG well normally requires a maximum of 10 to 15 people at a time, including personnel for logging and cementing activities. A 100’ square area is typically mowed to accommodate the rig and small reserve pits, about 6’ x 15’ x 15’ are constructed to serve all of the drilling wells on that site. A total of about 1acre is required for the two to five wells drilled on a site (the actual number of wells per site depends upon the number of coal seams to be developed at that site). Wells are completed using 7” steel well casing set and cemented to surface from the top of the target coal bed. Small diameter tubing and an electric submersible pump would be installed in the well. Topsoil is stripped and saved from any surface disturbing operation and used for reclamation of the disturbed area (Montana Board of Oil and Gas Conservation Environmental Assessment, 2003).

The operator will use existing roads and trails to the extent possible; an average of 15 miles or less of new gravel roadways would generally be used for this project. Electrical power and water and gas flow lines will generally follow the road system and, to the extent possible, will use the same right-of-way; power lines will be plowed in if possible to minimize surface disturbance.

Well heads will be equipped with 5’ frost boxes painted an unobtrusive color and fenced to protect the facility from damage by wildlife. Electronic flow devices will measure natural gas production and water will be measured through ultrasonic flow meters; a panel installed at the well starts and stops the pump based on fluid level measurement. Any interested companies must submit a surface use plan, water management plan, and reclamation plan as required in the BLM Onshore Oil and Gas Order #1.

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