INTRODUCTION

The Rawlins Field Office area lies within south-central and southeast Wyoming (Figure 1). The main goals of our analysis of a Reasonable Foreseeable Development scenario were to technically analyze the oil and gas resource occurring within the Field Office area and to project future development potential and activity levels for the period 2001 through 2020. It is a base line scenario and thus it assumes that future activity levels will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2002). We have recognized current legislatively imposed restrictions that could affect future activity levels and constrained this base line scenario where those types of restrictions have been applied to lands within the Field Office area.

The Reasonable Foreseeable Development scenario presented below reviews past and present exploratory and production operations and activities. It also presents occurrence potential for oil and gas, coalbed gas, and deep hydrocarbons (at depths greater than 15,000 feet) as well as available estimates of the hydrocarbon resources that may be present within the Field Office area. Factors used to project future activities include (but are not limited to) a review of published oil and gas resource information (including a number of on-line databases) for the area, a call for data from oil and gas operators, future oil and gas price estimates, petroleum technology research and development, geophysical activity, bid performance at lease sales, limitations on access, and infrastructure. The Reasonable Foreseeable Development scenario presented is not a worst-case scenario, but a reasonable and science based projection of the anticipated oil and gas activity that is based on information obtained and analyzed, and uses logical and technically based assumptions to make its projections.

Four management alternatives were evaluated for the Environmental Impact Statement for the Rawlins Field Office Resource Management Plan. Each alternative contains management imposed restrictions that may negatively affect oil and gas development. These restrictions can effectively decrease the base line estimated number of well locations in areas of Federal oil and gas ownership. For each alternative, we have analyzed the restrictions and estimated the number of well locations that could be reduced from the base line total. If restrictions for an alternative were determined to affect our base line projections of development potential, an additional development potential map was constructed.

Total Federal gas resource ownership in the Field Office area amounts to 5,280,720 acres (Advanced Resources International, 2001). The Bureau of Land Management (77%) and Forest Service (22%) manage most of the Federal mineral lands in the Field Office area. The Bureau of Reclamation and Fish and Wildlife Service manage smaller amounts of the Federal mineral lands. State and private minerals lands also lie within Field Office boundaries. Analysis prepared below includes data and information obtained from detailed research and makes future projections for all mineral land ownerships within the Field Office area.

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS

The following discussion brings together known information on past and present exploratory and production operations and activity for the Rawlins Field Office area. Information is presented in the approximate sequence that occurs when project areas or fields are explored and then developed. The sequence begins when initial exploratory activity begins, and ends when projects are abandoned.

EXPLORATORY OPERATIONS AND ACTIVITY

Exploratory activity includes:

- the study and mapping of surface and subsurface geologic features to recognize potential hydrocarbon traps
- determining a geologic formation's potential for containing economically producible hydrocarbons
- pinpointing locations to drill exploratory wells to test all potential traps
- drilling additional wells to establish the limits of each discovered trap
- testing wells to determine geologic and engineering properties of geologic formation(s) encountered
- completing wells that appear capable of producing economic quantities of hydrocarbons.

Hendricks (1995) studied the components that control and characterize potential gas accumulations in the Great Divide and Washakie basin portions of the Field Office area (Figure 2). These portions of the Field Office area have been of most exploratory interest in recent years and they are where most Field Office drilling activity has occurred. Hendricks reported that the major components "are:

1. Thick accumulations of sandstones, shales, and locally coal (potential source and reservoir rocks) exist in these basins.
2. Burial and thermal histories promoted the development and preservation of diagenetic pore throat traps and extensive gas generation.
3. Although the centers of basins are completely gas saturated, production is controlled by stratigraphy. Both basin-wide and local stratigraphic variations are important in creating traps and reservoirs (local compartments).
4. Structure also plays a role in localizing gas accumulations, especially when coupled with stratigraphy.
5. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, are important. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
6. The presence of fractures, both tectonic and produced by gas generation, is important to overall productivity.
7. Secondary porosity, produced by the dissolution of unstable grains and rock fragments, is important in both basin-wide and local accumulations."

Innovative drilling and completion techniques have enabled the industry to drill deeper (with fewer dry holes) and to recover more reserves per well. Smaller accumulations once thought to be uneconomic can now be produced. Nationally, increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). Our review indicates that this observation also applies to western Wyoming. Barlow & Haun, Inc (1994) reported that in the Greater Green River Basin, one rig was capable of drilling four wells per year in 1973. By the early 1980's they found that the rate had increased to seven wells per year per rig and it increased again to 10 wells per year per rig by 1994. Their review of gas well completions indicated that successful completions had gone from 30 percent in the early 1970's, to 45 percent in the early 1980's, to about 85 percent by 1993. Industry is drilling fewer dry holes and reducing the number of wells needed to fully develop each reservoir. During the early 1990's, activity was focused almost entirely on very low risk development drilling in and around known field areas, which helped to improve the overall success rate. More future exploratory drilling will be required to discover new resources. Since the risk of failure is higher for this type of activity, the overall success rate could decline slightly in the future.

Advances in technology have boosted exploration efficiency, and additional future advances will continue this trend. Significant progress that has and will continue to occur is expected in:

- computer power, speed, and accuracy
- remote sensing and image-processing technology
- developments in global positioning systems
- advances in geographical information systems
- three-dimensional and four-dimensional time-lapse imaging technology that permits better interpretation of subsurface traps and characterization of reservoir fluid
- improved borehole logging tools that enhance our understanding of specific basins, plays, and reservoirs
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

These new technologies will allow companies to target higher-quality prospects and improve well placement and success rates. As a result, fewer drilled wells will be needed to find a new trap, and total production per well will increase (U.S. Department of Energy, 1999). With fewer wells drilled, surface disturbance and volumes of waste, such as drill cuttings and drilling fluids is reduced. An added benefit of improved remote sensing technology is the ability to identify hydrocarbon "seeps" so that they can be cleaned up. These seeps can also help pinpoint undiscovered hydrocarbons.

Technology improvements have also cut the average cost of finding oil and gas reserves in the United States. U.S. Department of Energy (1999) estimated finding costs were approximately \$12 to \$16 per barrel of oil equivalent in the 1970's. Currently, finding costs have dropped to \$4 to \$8 per barrel.

FEDERAL OIL AND GAS UNIT AGREEMENTS

Non-coalbed gas and coalbed gas Federal unit agreements lay within The Field Office boundary. Seventy-one active (non-coalbed gas) Federal unit agreements lie within or partially within the Field Office boundary (Figure 3). Most Federal unit agreements were initially approved as exploration tools to investigate non-producing parts of the Field Office area. Some have found and developed oil and gas and are now considered to be producing units. Others are still in an exploratory stage of development. These units cover an area of 397,213 acres, or about 3.54 percent of the Field Office area. Companies operating more than one unit are; Devon Energy Prod. (seven units), BP America Prod. (seven units), Yates Petroleum (six units), Questar Exploration & Production Co. (six units), Anadarko Exploration and Production Co. (five units) Merit Energy Co. (five units), Kaiser-Francis Oil (four units), Tom Brown Inc. (three units), Wold Oil Properties Inc. (two units), Cabot Oil & Gas Corp. (two units), EOG Resources Inc. (two units), and Goldmark Engineering Inc. (two units). Twenty other companies (Benson-Montin-Greer, Braden-Deem Inc., Chevron/Texaco, Coral Production Corp., Double Eagle Petroleum Co., Hudson Group LLC, Marathon Oil Co., Ocean Energy Inc., Richardson Operating Co., Rock River Operating Inc., Sonoma Energy Corp., Stanley Energy Inc., Westport Oil & Gas Co. LP, Windsor Oil & Gas Inc., Xeric Oil & Gas Corp., Bluebonnet Energy Corp., Davis Petroleum Corp., EnCana Oil & Gas, Mountain Fuel Supply, and Thorofare Resources.

Most of the units are located in the Greater Green River Basin area, with two in the Denver Basin and three each in the Hanna and Laramie basins. Nearly all of these units are generally at a mature stage of development. In recent years some new exploratory unit agreements have been proposed and approved in the Washakie and Great Divide portions of the Greater Green River Basin. These units are in early stages of exploratory activity.

At present, four coalbed gas exploratory unit agreements have been authorized and four are pending (Figure 4 and Table 1) within the Field Office area. These eight active units cover an area of about 140,336 acres or about 1.3 percent of the Field Office area. Four other unit proposals have been cancelled or withdrawn, one unit has terminated, and the last is unknown. The terminated Hanna Draw Unit lies within the Hanna Basin. Tests of coals in the Tertiary aged Hanna Formation in this unit are continuing, just not as part of a unit plan. Economic viability of this area has not yet been determined.

Three approved coalbed gas units (Blue Sky, Brown Cow, and Sun Dog), the four pending units, and four cancelled or withdrawn unit proposals (Table 1) are located along the east flank of the Washakie Basin. In addition, an older Lower Cretaceous producing unit (Cow Creek) has also begun to develop and produce the shallower coalbed gas resource. The Sun Dog Unit (Figure 4) partially surrounds the Cow Creek Unit on its northwest boundary. All of the above unit areas are part of a larger proposal by Petroleum Development Corporation and others, to test coal gas in an area between townships 13 and 20 north, and ranges 89 and 92 west. This proposal is known as the

“Atlantic Rim Project” and testing of Cretaceous aged coals of the Mesaverde Group has begun. A separate environmental impact statement is being prepared for this proposed project. Initial wells for pilot tests in the Sun Dog and Blue Sky units have been drilled and testing has begun. Drilling and pilot testing will soon begin on the Brown Cow Unit. Drilling and pilot testing on pending units will also begin soon after approval, if approval is obtained.

East Pappy Draw Unit (Figure 4) lies on the northeast edge of the Greater Green River Basin. Drilling and pilot testing has not yet begun.

The Magic Unit proposal lies on the west-center boundary of the Field Office, along the crest of the Wamsutter Arch, which lies between the Great Divide and Washakie basins. It appears that this unit proposal will not be approved.

TYPICAL DRILLING AND COMPLETION SEQUENCE

The drilling and completion sequence for a target reservoir in the Rawlins Field Office area generally involves:

- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate, which all result in easier penetration of the earth’s surface
- inserting casing and tubing into each well to protect the subsurface and control the flow of fluids (oil, gas and water) from the reservoir
- perforating the well casing at the depth of the producing formation to allow flow of fluids from the formation into the borehole
- hydraulically fracturing the formation to increase permeability and the deliverability of oil and gas to the borehole
- installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts.

Advanced Resources International (2001) used industry guidance to determine the average time required to drill and complete a well within certain depth ranges. They predicted an average time of 40 days to drill and complete a well of less than 10,000 feet, 65 days for wells between 10,000 and 14,000 feet, and 190 days for wells greater than 14,000 feet.

Drilling improvements have occurred in new rotary rig types, coiled tubing, drilling fluids, and borehole condition monitoring during the drilling operation. Technology is allowing directional and horizontal drilling use in many applications. New bit types have boosted drilling productivity and efficiency. New casing designs have reduced the number of casing strings required. Environmental benefits of drilling and completion technology advances include:

- smaller footprints (less surface disturbance)
- reduced noise and visual impact
- less frequent maintenance and workovers of producing wells with less associated waste

- reduced fuel use and associated emissions
- enhanced well control for greater worker safety and protection of groundwater resources
- less time on site with fewer associated environmental impacts
- lower toxicity of discharges
- better protection of sensitive environments and habitat.

HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED

Earliest drilling activity within the Field Office area was a dry hole drilled in Albany County in 1906. The first discovery was made in Sweetwater County at Lost Soldier Field in 1916. Four other field discoveries (in Carbon County) were made before 1920: Allen Lake and Rock River were discovered in 1918 and Ferris East and Mahoney Dome were discovered in 1919. Records show that 105 wells were drilled before 1920 (IHS Energy, 2003). Early fields produced mostly oil. An acceleration of gas drilling activity has been occurring in recent years. This acceleration is at least partly in response to increased knowledge of the area, generally improved gas prices, and improvements in techniques used to drill and complete wells.

Drilling and Completion Activity

A total of 5,962 wells, in five status categories, exist within the Rawlins Field Office boundary (Table 2). To date, 47 percent of all wells have been drilled on Federal lands, with the other 53 percent drilled on fee or state lands. Fifty percent of all drilled wells have been abandoned. Wells have been abandoned because:

- they were “dry”--no hydrocarbons were encountered, or hydrocarbons were not present in economic quantities
- they initially were capable of producing hydrocarbons, but they became uneconomic to produce at a latter date
- mechanical difficulties within a borehole prevented economic hydrocarbon production.

A map of the Field Office area shows locations of all wells drilled (Figure 5). For this map we considered active wells to be those that the Wyoming Oil and Gas Conservation Commission (2003a) determined to be in a drilling, dormant, notice of abandonment, or completed status. All other wells we considered to be abandoned. We also prepared a map of the Field Office area that shows all oil and gas fields, the major structural basins, and major synclinal axes (Figure 2). The location of the synclinal axis of each basin marks the thickest package of sedimentary rocks within that particular basin. The Hanna Basin contains the thickest package of sedimentary rocks. Both maps show that the most heavily tested region of the Field Office is in the easternmost part of the Greater Green River Basin (westernmost part of the Field Office area) and is made up of parts of the Great Divide Basin, Wamsutter arch, and Washakie Basin. The Wamsutter arch lies between and separates the Great Divide Basin from the Washakie Basin. This region has produced most of the gas found in the Field Office area and large amounts of oil. Even though numerous wells have been drilled in this region of the Field Office, some townships have only been lightly tested.

The two other areas of concentrated activity, within the Field Office area, lie in its eastern part (Denver-Cheyenne Basin area) and in an area across its center (Hanna, Laramie, and Kindt basin areas). Production has been predominantly oil. These areas have been less heavily explored and developed than in the area to the west. Many townships within these two areas have been only lightly tested. Outside of the three active areas, many townships have not been tested at even one location.

The Greater Green River Basin has been a significant regional producer of gas (Barlow & Haun, Inc., 1994) for more than 75 years. In other parts of the basin gas discoveries were made at Baxter Basin Field in 1922, LaBarge Field in 1925, and Hiawatha Field in 1926. In 2002, the Rawlins Field Office area contained five of the top 25 producing gas fields in Wyoming (Rocky Mountain Oil Journal, 2003 and Wyoming Oil and Gas Conservation Commission, 2003b). All five fields lie in the easternmost part of the Greater Green River Basin (westernmost part of the Field Office area). Locations of these are shown on Figure 2. Four fields (Echo Springs, Standard Draw, Wamsutter, and Wild Rose) produced more than 110 billion cubic feet of gas in 2002. Six natural gas plants process gas for sale within the Field Office areas. Those plants are:

- Borie – located in Laramie County and first producing in 1988, no production reported since 1998
- Echo Springs – located in Carbon County and first producing in 1994
- Rawlins – located in Carbon County and first producing in 1966
- Red Desert – located in Sweetwater County and first producing in 1991
- Silo – located in Carbon County and first producing in 1994
- Wamsutter – located in Carbon County and first producing in 1984.

The reported gas production from the fifth field, Lost Soldier Field, is actually mostly carbon dioxide gas. This carbon dioxide was brought via pipeline from western Wyoming and is first injected into this oil reservoir to increase oil production rates. The gas is later recovered and recycled at the Bairoil gas plant for reinjection back into the producing reservoir.

Oil and gas fields in the Field Office area have made a smaller contribution to the state's oil production. Oil was first discovered in 1916, at Lost Soldier Field (Figures 2 and 5). Historically, Lost Soldier Field and the nearby Wertz Field have contributed a large part of the Field Office area's oil production. This remains the case today. In 2002, the Lost Soldier Field produced the fourth highest amount of oil in the state (Wyoming Oil and Gas Conservation Commission, 2003b). It produced 1,945,056 barrels of oil. The Field Office area contains only two other top-25 oil fields. In 2002, the 18^{th} largest, Wertz Field, produced 597,721 barrels of oil and Echo Springs Field, the 25^{th} largest, produced 410,552 barrels of oil.

The rocks in the Field Office area range in age from Precambrian to Tertiary. The Hanna Basin contains the thickest section of sedimentary rock above the Precambrian basement.

The Precambrian is about 30,000 to 40,000 feet deep in the eastern part of this basin (Wilson et al., 2001 and Hansen, 1986). Figure 6 presents the names of stratigraphic units recognized in the Greater Green River Basin. Those stratigraphic unit names presented for the "east" and "east-central" parts of the basin are those generally recognized and most often used within the Field Office area.

Producing well symbols on Figure 6 mark those stratigraphic intervals known to produce oil and gas within the Field Office area. Of the Tertiary aged stratigraphic units: the Wasatch, and Fort Union formations produce oil and gas in the Field Office area, and the Hanna Formation has been completed in coal beds in the Hanna Basin. Cretaceous aged stratigraphic units are the dominant producers within the Field Office area. Mesaverde Group coalbeds have been completed in the Washakie Basin portion of the Field Office area. Of the older stratigraphic units, the Nugget Sandstone (producing mostly oil) has been most productive. Only minor amounts of oil and gas have been produced from limited numbers of wells completed in the other older stratigraphic units indicated as producers on Figure 6.

Coalbed gas exploration and development is at a very early stage within the Field Office area. Figure 7 shows where drilling activity has occurred. Wells have been drilled in a number of areas, although only four areas have a record of production. Many wells are waiting on testing to begin. Two areas in the Hanna Basin and two in the Washakie Basin have reported some gas production, all from coalbeds within the Mesaverde Group. Within the terminated Hanna Draw Unit area (townships 23 and 24 north, range 81 west), 11 wells have reported at least some coalbed gas production (Wyoming Oil and Gas Conservation Commission, 2003a). All those wells are presently abandoned or shut in. Cumulative production was only 1.502 million cubic feet of gas and more than 2.3 million barrels of water. Cumulative per well production ranged from 1 – 777 thousand cubic feet of gas and 21,654 – 350,556 barrels of water.

Dudley & Associates LLC operates eight producing coalbed gas wells some distance west of the Hanna Draw Unit (townships 23 and 24 north, range 85 west). Cumulative production has been 4.303 million cubic feet of gas and almost 3.6 million barrels of water over a 17 to 24 month period. August 2003 per well production ranged from 0.4 - 4 thousand cubic feet of gas per day and 723 – 2,036 barrels of water per day.

The Washakie Basin's Cow Creek Field/Unit, and area adjacent to it on the east (township 16 north, ranges 91 and 92 west), has been the most prolific of the four areas with a production history. Five Cow Creek Field/Unit wells produce gas from coalbeds and have 3 – 18 month reported production histories. Cumulative production has been 269.332 million cubic feet of gas and almost 1.3 million barrels of water. August 2003 per well production ranged from 2 - 641 thousand cubic feet per day and 531 to 1,503 barrels of water per day. Four wells, immediately east of Cow Creek Field/Unit have been producing coalbed gas for 15 months. Cumulative production has been 340.718 million cubic feet of gas and over one million barrels of water. August 2003 per well gas production ranged from 64 – 680 thousand cubic feet per day.

At Dixon Field (Figure 7), some of the oldest coalbed gas tests have been made in the Field Office area. Eleven wells were drilled in 1990 and 1991 to test Almond Formation coals. Testing and production lasted through 1995. One well has been abandoned and the others have been shut in since the end of 1995. All wells initially produced gas and water, but all were producing only water when shut in. Cumulative per well gas production ranged from 160 thousand cubic feet to 47.687 million cubic feet. Total reported production has been 101.1 million cubic feet of gas. Large volumes of water were produced (almost 7.4 million barrels) indicating that proximity to the water recharge area and high coal permeability would not allow these coals to be economically dewatered.

Deep Well Drilling and Completion Activity

Dyman et al. (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to depths greater than 15,000 feet. Figure 8 shows areas of the Rawlins Field Office that may contain potential reservoir sediments below 15,000 feet and those that do not appear to contain potential deep reservoir sediments at those depths. Only about 25 percent of the Field Office area may contain potential reservoir sediments below 15,000 feet. Those areas are in deep parts of the Great Divide, Washakie, and Hanna basins and along the Wamsutter Arch, which separates the Great Divide and Washakie basins (see Figure 2 for location of these structural features). The rest of the Field Office area (about 75 percent): the margins of the three deep basins, structural uplifts, and the shallow Denver-Cheyenne, Laramie, and Shirley basins appears to contain only igneous and metamorphic rocks below 15,000 feet. Only one well in Wyoming (at Lost Soldier Field) reportedly has produced hydrocarbons in the Precambrian. This well produced a small amount of gas (1.8 million cubic feet) over a three-month period in the early 1980's and has been plugged back to produce from shallower zones. Precambrian production in that well was reported at depths of less than 10,000 feet.

The Potential Gas Committee (2002) has projected large amounts of total undiscovered natural-gas resources in the onshore lower 48 states, at depths below 15,000 feet. For the entire Greater Green River and Hanna-Laramie basins, the Potential Gas Committee estimated almost one third (8.359 of a total of 26.813 trillion cubic feet of gas) of the potential resource (coal-bed gas not included) lies below 15,000 feet. This potential resource estimate was projected for an area larger than that of the Field Office area. We expect that a smaller, but still significant portion of this potential resource will lie within the area of the Field Office. Information presented below will show that deep hydrocarbon resources exist within the Field Office area and that there is potential for the discovery of additional reservoirs

Deep wells drilled in the Field Office area are shown on Figure 8. Wells completed as producers in a deep formation are shown with a gas well symbol. All other deep wells have been assigned a drilled and abandoned symbol or suspended symbol on Figure 8. Information relating to these wells is presented in Table 3.

Forty-three deep wells have been completed. To date; 17 wells have been drilled between 15,000 and 16,000 feet, 13 have been drilled between 16,000 and 17,000 feet, six have been drilled between 17,000 and 18,000 feet, and six have been drilled between 18,000 and 19,000 feet. The deepest well, and only well drilled to a depth greater than 19,000 feet, was the Frewen Deep #1. That well was drilled to 19,299 feet in the Frewen Field, on the north edge of the Washakie Basin. The Frewen Deep #1 also is the deepest producing well in the Field Office. It was originally completed as a Cretaceous Lakota Formation gas producer between 19,054 and 19,126 feet. This zone produced 168 million cubic feet of gas and eight barrels of oil before it was abandoned.

Three of the 43 wells have only recently been drilled, and they are considered suspended until testing has been completed and a final status is determined (Table 3). Twenty-eight of the 40 completed wells (70 percent) were originally completed as gas wells. Nineteen of those 28 wells (68 percent) produce, or have produced, from zones deeper than 15,000 feet. Production in these deep wells has been dominantly gas, with about 96.7 billion cubic feet of gas produced. Gas has been encountered in nine different deep formations, with the Nugget Sandstone productive in eight wells. Oil has been produced in small amounts, along with gas, in nine of the 18 wells. Only the Madison Limestone and Weber Sandstone, at Table Rock Field, are known to contain some hydrogen sulfide gas.

<u>Hanna Basin Deep Wells</u>

Only three deep wells (Pass Creek Unit No. 1, St. Marys Unit No. 1, and Seminoe Unit No. 1-25 see Table 3) have been completed in the Hanna Basin. All were drilled as part of Federal exploratory unit agreements. None have been productive nor had hydrocarbon shows in zones deeper than 15,000 feet. The Seminoe Unit No. 1-25 was completed as a shallower, Lewis Shale gas producer. It was completed in 1983 and was the last deep well drilled in the Hanna Basin.

Wilson et al. (2001) have reviewed the potential for a deep basin-centered gas accumulation in the Hanna Basin. Limited data indicates that a gas-charged, overpressured interval may occur along south and western margins of the basin. In this area, the Cretaceous Mowry, Frontier, and Niobrara formations lie in this potential gas-charged overpressured interval, at depths below 10,000 feet. In the center of the basin, Wilson et al. (2001) project possible gas-charged overpressuring at depths below 18,000 to 20,000 feet.

<u>Great Divide Basin Deep Wells</u>

Nine deep wells were completed (Table 3) in the east and north parts of the Great Divide Basin (Figure 8). Three of the nine wells produce, although only two were completed as producers from reservoirs at depths greater than 15,000 feet. Production has been only small from one of the wells.

The first deep test was the Cyclone Rim Unit No.1 dry hole. The third deep well completed in this area was the Bull Springs Rim No. 1-19. It is the deepest well drilled in the basin and it also produces from the greatest depth. The Cretaceous Niobrara Formation produces from 15,383 to 15,478 feet in this well.

To date, the oldest formation encountered was the Lower Cretaceous Cloverly, in the Bull Springs Rim No. 1-19. The other eight wells only drilled to Upper Cretaceous aged sediments. All nine wells were completed in the 1972 to 1980 period.

Wamsutter Arch Deep Wells

The Wamsutter Arch only occupies a small part of the Field Office area. It is a low relief anticlinal structure separating the Great Divide and Washakie basins (Figure 2). Four deep wells have been completed on the crest of this structure (Table 3). One is presently suspended and another is temporarily abandoned. Two other wells are productive, but not from the deep part of the borehole. In the Sidewinder No. 1-H, No. 2-H, and No. 3-H wells, a part of the borehole was horizontally drilled. All wells have drilled to Lower Cretaceous formations, with the first completed in 1997.

Washakie Basin Deep Wells

Most of the deep wells (27 of 43 wells, Table 3) in the Field Office area are scattered across the Washakie Basin (Figure 8). The earliest well was completed in 1960. Twenty-one of these wells were drilled in the 1975 to 1996 period. Five new deep wells have been drilled from 2001 to present.

The first deep well in the Washakie Basin was the South Baggs Unit No. 8 drilled to 16,248 feet in 1960. It drilled completely through the sedimentary section, into Precambrian basement rocks, in the South Baggs Field. The Upper Cretaceous Lewis Shale was found to be productive at depths less than 15,000 feet.

Deepest production is in the Frewen Deep No. 1. This well was completed as a Lower Cretaceous Lakota Sandstone gas well in 1989. It produced in an interval from 19,054 to 19,126 feet and has since been abandoned.

Twelve deep wells have been drilled within that portion of the Table Rock Field, which lies within the Field Office area (Table 3). Table Rock Unit No. 125 was recently drilled and is waiting on borehole tests. The other 11 wells were all completed as deep producers; eight in the Triassic Nugget Sandstone, two in the Pennsylvanian Weber Sandstone, and one in the Mississippian Madison Limestone. Most of the deep production in the Field Office area has come from these wells. Hydrocarbons are produced from an anticlinal structure at Table Rock Field. The Weber and Madison contain about 2 percent hydrogen sulfide (Dickinson, 1992).

Formations productive at Table Rock Field have not been found to be productive in other parts of the Washakie Basin portion of the Field Office area. Outside Table Rock Field, a number of different formations have been found to be productive below 15,000 feet. Those productive formations are: the Upper Cretaceous Lewis Shale, Mesaverde Group, and Niobrara Formation; the Lower Cretaceous Lakota Sandstone; and the Pennsylvanian Morgan Formation.

Reported deep gas production in the Field Office part of the Washakie Basin has totaled 96.709 billion cubic feet. Only a small amount of oil (11,090 barrels) has been produced from these wells.

Drilling Techniques in Use

Improvements in drilling technique have allowed avoidance of sensitive surface features, recovery of additional oil and gas reserves, reduced drilling time, reduced associated waste volumes, reduced emissions, and greater protection of sensitive environments. Techniques that have been used within the Field Office, or may be used in the future, are presented below.

Directional and Horizontal Drilling and Completion Activity

Oil and gas wells traditionally have been drilled vertically, to depths ranging from a few hundred feet at locations scattered across the Field Office and to 19,299 feet in the Lakota Formation gas well in the northeastern Washakie Basin (Frewen Field, section 13 of township 19 north, range 95 west). Depending on subsurface geology, technology advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Directional and horizontal drilling use a deviated borehole to enable operators to reach reservoirs that are not located directly beneath the drilling rig, or to allow the borehole to contact more of the reservoir. In parts of the Field Office area, the capability to directionally drill has been useful in avoiding sensitive surface features or areas of environmental concern.

Drilling and completion costs for directional and horizontal boreholes are higher than for conventional vertical boreholes. The risk of losing the borehole due to technical drilling difficulties is also higher. Because of these factors, industry generally prefers not to drill directional or horizontal wells unless other concerns make this option necessary. An exception to this general rule can be made if industry can determine reservoir conditions are suitable for using this type of borehole to contact more of the reservoir (increase drainage area) and increase productivity. In this case, the potential for increased productivity may offset the additional drilling costs, making this type of borehole the preferable drilling option. Eustes (2003) has identified a number of items that have the potential to raise drilling costs for these types of wells. They are:

- special directional drilling equipment (mud motor, measurement while drilling tools, and extra personnel) is required
- a larger rig may be needed which would require larger mud pumps
- casing and tubing design may need modification to overcome problems with ovality and bending stress
- borehole risk may be higher due to tectonic stress
- slower rate of penetration requires more drilling time on the location
- torque and drag on borehole equipment is higher.

Figure 9 shows the locations of known directional wells and current applications to drill new directional wells. These locations are concentrated in the Washakie and Great Divide basin parts of the Field Office, with a small number drilled in the Hanna, Laramie, and Denver basins. Table 4 shows how wells in each status category are distributed in each part of the Field Office area. Within the Field Office area, industry has drilled 182 known directional wells (IHS Energy, 2003), and drilling and testing has begun on two others. Applications to drill eight additional directional wells have also been approved.

In the Washakie and Great Divide basin parts of the Field Office area, the successful productive completion rate (not including injection wells) of directional wells has been 97 percent. In the other areas, the successful completion rate is 75 percent of the wells drilled. The high success rate in both areas is mainly due to the fact that almost all wells drilled have been field development wells. Industry prefers not to drill wildcat wells directionally, since details of geology and potential reservoir characteristics are not yet known and directional drilling adds an extra element of risk and increased costs. The abandoned wells appear to have been nonproductive or not economic to produce.

The earliest known directional well was completed in 1984 as an oil well in Lost Soldier Field. Fewer than seven directional wells were completed in any year until 1994, when 11 wells were completed. The pace of directional drilling then accelerated through 1998, when 44 directional wells were drilled. In recent years, directional drilling activity has fallen back to pre-1994 levels. Although directional drilling has proven to be technically feasible in the Field Office area, target reservoirs contain relatively low average hydrocarbon volumes. These lower volume reservoirs are less attractive for this higher cost drilling technique.

Amoco Production Company (now BP Amoco) has drilled a majority of the directional wells (116). Only three other companies (Union Pacific Resources; now Anadarko Petroleum Corporation, Marathon Oil Company, and Snyder Oil Corporation; now Devon SFS Operating) have drilled more than ten wells each. To date, productive completions have been made in 13 different stratigraphic intervals. Most directional wells (151 wells) have been completed in Upper Cretaceous formations (see Figure 6). Almost all these wells are gas wells. A small number of wells produce from older formations (15 wells). Most of these wells are oil wells. The oldest producing formation is the Lower Cambrian Flathead Sandstone. The directional water injection wells were completed in the Madison Limestone and Tensleep Sandstone in order to enhance oil production from those intervals at Lost Soldier and Wertz fields.

In the Echo Springs-Standard Draw-Wild Rose-Creston-Baldy Butte-Coal Gulch Field complex, and in the Siberia Ridge-Wamsutter field area, 130 directional wells have been drilled to Upper Cretaceous gas targets. In these fields, up to five wells (including one vertical well) were drilled from a single surface location. Operators were using directional wells to avoid causing extensive surface disturbance and to try to reduce drilling and operating costs. Indications are that operators were only successful in reducing overall costs in some instances (when they could drill four or more wells from one surface location).

Directional drilling depths in the Field Office area have ranged from 1,950 to 17, 680 feet. Shallower directional wells have been drilled in the Laramie and Hanna basins and along the eastern margins of the Washakie and Great Divide basins. Most wells (122 wells or 67 percent) have been drilled in the 8,930 to 11,200 foot range. Wells completed at these depths produce from Upper Cretaceous aged stratigraphic units (Lewis Shale, Almond Formation, and Mesaverde Group).

Industry does not use horizontal boreholes to avoid sensitive surface features or areas of environmental concern. Other types of directional boreholes are used to meet these concerns, as discussed above. Horizontal borehole drilling and completion costs are higher than those for a vertical or other type of directional borehole. A number of reasons to drill horizontal boreholes have been identified by Eustis (2003). They are:

- ability to intersect many fractures
- minimize premature entry of water or gas into the borehole
- increased drainage area
- ability to intersect layered reservoirs at high dip angles
- improve coal gas production
- increase productivity
- improve injection of water, steam, and etc.

The benefits from increased production can, in some cases, outweigh the added cost of drilling this type of well. Other reasons listed above, allow improved management of the reservoir, which may justify the increased drilling and completion costs.

To date, 89 horizontal boreholes have been drilled (IHS Energy, 2003 and Wyoming Oil and Gas Conservation Commission, 2003a) within the Rawlins Field Office area (Figure 10). Most of these wells (71 wells) have been drilled in the Silo Field area.

The Silo Field reservoir (Niobrara Formation, which is equivalent to the Mancos Shale on Figure 6) contains many fractures. Horizontal boreholes have been used at Silo Field to encounter as many Niobrara Formation fractures as possible. At other locations within the Field Office, horizontal boreholes have less commonly been used to intersect fractures. They appear to have mainly been used to contact more of the reservoir (increase drainage area) and to increase productivity. These drilling targets can be hydrocarbons in thin, tight reservoirs, or targets that allow a borehole to contact more of a reservoir, so more of the hydrocarbon resource can be recovered from a single well. The benefits from increased production can, in some cases, outweigh the added cost of drilling these wells.

Since 1994, 12 horizontal wells have been drilled in the Washakie and Great Divide basins, and another has been spud. Amoco Production Company (now BP Amoco), Union Pacific Resources (now Anadarko Petroleum Corporation), Texaco Exploration and Production (now ChevronTexaco), and Vessels Oil and Gas Company drilled these wells. Thorofare Resources operates the spud well. All 12 wells are active, with seven producing gas, four producing oil, and one completed as an injection well at Lost Soldier Field. Five of the gas wells and two oil wells produce from Upper Cretaceous sediments. One gas well and one oil well were completed in the Lower Cretaceous Frontier Formation, one gas well produces from the Pennsylvanian Tensleep Sandstone, and the Mississippian Darwin Sandstone produces oil from the final well. Drilling depth ranges have been from as shallow as 5,295 feet at Lost Soldier Field, to 17,043 feet in the Sidewinder #2-H well drilled in section 30 of township 20 north, range 96 west.

Union Pacific Resources (now Anadarko Petroleum Corporation) drilled two horizontal wells in the small Kindt Basin, southeast of Rawlins. Both were completed as Cretaceous aged tests in 1993, and were abandoned. Drilling depths were around 7,000 feet.

The rest of the horizontal wells (74 wells) have been drilled in the Denver Basin, with 71 of those wells drilled at Silo field. Union Pacific Resources (now Anadarko Petroleum Corporation) and Exxon Corporation drilled most of these wells. Of the wells drilled outside of Silo Field, one well produces oil from the Niobrara Formation and the other two were drilled and abandoned.

Silo is an oil field discovered in 1980. Forty vertical boreholes were drilled before the first horizontal borehole was completed in 1990. Almost all horizontal boreholes at Silo produce or have produced oil. One well was abandoned during drilling, due to borehole complications encountered during the drilling and completion process. Two others had to be abandoned after a period of production, also due to borehole complications. Lateral distance drilled in the productive zone has been up to 4,000 feet in early horizontal wells (Sonnenberg and Weimer, 1993). The last horizontal borehole was completed in March of 1998. Production is from the fractured Niobrara Formation at depths ranging from 7,600 to 8,500 feet (Sonnenberg and Weimer, 1993).

The high success rate of horizontal boreholes within the Field Office area is mainly due to the fact that almost all wells drilled have been field development wells. Industry prefers not to drill wildcat wells horizontally, since details of geology and potential reservoir characteristics are not yet known and horizontal drilling adds an extra element of risk and increased costs. As discussed above, some boreholes have had to be abandoned due to borehole complications. The other abandoned wells have been nonproductive or not economic to produce.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in western and southern Wyoming. It has the potential to improve efficiency and reduce costs of both exploration and production drilling. Coiled tubing—used effectively for drilling in reentry, under balanced, and highly deviated wells—is often used in slimhole drilling. U.S. Department of Energy (1999) reported that a conventional 10,000-foot well in southwest Wyoming costing $700,000 could be drilled for $200,000 by using slimhole and coiled tubing. We expect both of these drilling and completion techniques to be used more often in the future. U.S. Department of Energy (1999) has identified the environmental benefits of using these techniques, which include:

- lower waste volumes
- smaller surface disturbance areas
- reduced noise and visual impacts
- reduced fuel use and emissions
- protection of sensitive environments.

<u>Light Modular Drilling Rigs</u>

Now in production, new light modular drilling rigs can be more easily used in remote areas and are quickly disassembled and moved. Rig components are made with lighter and stronger materials and their modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions.

Light modular rigs also have potential for use in situations where pad drilling is being used. Pad drilling refers to the drilling of multiple directional boreholes from one surface location. Pads are the flat graded land surfaces that serve as the foundation for the drilling rig. Since modular rigs allow quicker breakdown and movement to new locations, they reduce time to drill and rig costs.

In pad drilling, more than one borehole is drilled from the same pad. A development plan is required for pad drilling to determine the layout of surface facilities that will be needed, the location of each borehole to be drilled, and the sequence in which each borehole is drilled. Extra planning is required because pad drilling requires that each borehole will be a directional drilled well. Since each borehole is close to other boreholes, its near surface trajectory needs to be controlled so that it does not accidentally intersect those other boreholes.

Pad drilling can be used to avoid surface locations that would be difficult to reach due to topography and to reduce total surface disturbance where close-spaced infill drilling is proposed.

<u>Pneumatic Drilling</u>

Pneumatic drilling is a technique in which boreholes are drilled using air or other gases rather than water or other drilling liquids. This type of drilling can be used in mature fields and formations with low downhole pressures and where formations are sensitive common fluids used in drilling. Some parts of the Field Office area contain overpressured producing formations (Great Divide, Washakie, and Hanna basin areas and the Wamsutter Arch) that will not be receptive to this type of drilling. It is an important tool that can be used when drilling horizontal wells, so it could be used in the far eastern part of the Field Office area (Silo Field on Figure 10) if additional horizontal boreholes are drilled. This type of drilling significantly reduces waste and surface disturbance, shortens drilling time, and decreases power consumption and emissions.

Measurement-While-Drilling

Measurement-while-drilling systems measure borehole and formation parameters during the actual drilling process. These systems allow more efficient and accurate drilling. They can reduce costs, improve safety of operations, reduce time on site, and fewer wells may need to be drilled. At present, measurement-while-drilling is most often used when drilling horizontal boreholes. In the future, use of this type of system may become more widespread and may find applications for other types of directional boreholes.

Improved Drill Bits

Advances in materials technology and bit hydraulics have yielded tremendous improvements in drilling performance. The latest-generation polycrystalline diamond compact bits drill 150 to 200 percent faster than similar bits did just a few years ago (U.S. Department of Energy, 1999). Peterson (2001) studied drill bit technology improvements in one area of the Field Office and two other parts of the Greater Green River Basin. In the Wamsutter Field area (Figure 2) he studied the period from 1992 to 2000. During that period, he found that the rate of penetration increased from an average of 31.1 to 57.3 feet per hour and total drilling time was cut from 307.25 to 176.5 hours for 9,000- to 11,000-foot wells. Peterson (2001) estimated that this increased efficiency had reduced drilling costs by 43 percent.

At Jonah Field in the north-central part of the Greater Green River Basin, he studied the period from 1994 to 2000. During that period, rate of penetration increased from an average of 29.6 to 42.7 feet per hour and total drilling time was cut from 374.3 to 252.9 hours for 10,000- to 13,000-foot wells. Peterson estimated that this increased efficiency had reduced drilling costs by 31 percent.

Peterson (2001) also studied the Moxa Arch area on the west part of the Greater Green River Basin. During the 1993 to 2000 period, rate of penetration increased from an average of 47.9 to 72.7 feet per hour for 10,000- to 11,000-foot wells. Total drilling time was cut from 220.3 to 144.5 hours during that period. Peterson estimated that this increased efficiency had reduced drilling costs in this area by 39 percent.

Environmental benefits of improved bits include:

- lower waste volumes
- reduced maintenance and workovers
- reduced fuel use and emissions
- enhanced well control
- less time on site
- less noise.

Reducing time the rig is on the drill site reduces potential impacts on soils, groundwater, wildlife, and air quality.

Completion Techniques in Use

Standard completion techniques for the Field Office area will be described below. Once the operator determines that a well should be completed for production, the first step is to place casing in the borehole and cement it in-place. Since the potential producing zones are then sealed off by the casing and cement, perforations (holes made through the casing and cement and into the formation) are made in order for the oil and/or gas to flow into the borehole.

Some form of hydraulic fracturing is then usually used to improve hydrocarbon flow into the borehole. Hydraulic fracturing of reservoirs enhances well performance, minimizes drilling, and allows the recovery of otherwise inaccessible oil and gas resources. The flow of hydrocarbons is restricted in some low-permeability, tight formations and in unconventional resources (such as coalbed gas), but can be stimulated by hydraulic fracturing to produce economic quantities of hydrocarbons. Fluids are initially pumped into the formation at pressures high enough to cause fractures to open in the reservoir rock. Sand slurry is pumped into the opened fractures which keep the fractures propped open, allowing hydrocarbons in the reservoir to more easily enter the borehole. Improvements such as carbon dioxide-sand fracturing, new types of additives, and fracture mapping, promise more effective fractures and greater ultimate hydrocarbon recovery. Improvements in hydraulic fracturing technology have encouraged the extensive development of Upper Cretaceous formations in the Great Divide and Washakie basins.

The final completion step is to place producing tubing in the borehole to carry the hydrocarbons to the surface. At the surface it is connected to a Christmas tree (a collection of valves) used to control the well's production.

PRODUCTION AND ABANDONMENT TECHNIQUES IN USE

Once production begins, reservoir management is needed to ensure that as much hydrocarbon as possible is produced at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of the oil in a given field and sometimes the associated natural gas was vented or flared. Newer recovery techniques have allowed the production of up to 50 percent of the oil. Also, 75 percent or more of the natural gas in a typical reservoir is now recovered. Operators have taken significant steps in reducing production costs. U.S. Department of Energy (1999) estimated that costs of production had decreased from a range of $9 to $15 per barrel of oil equivalent in the 1980's to an average of about $5 to $9 per barrel of oil equivalent in 1999.

Since 1990, most reserve additions in the United States—89 percent of oil reserve additions and 92 percent of gas reserve additions—have come from finding new reserves in old fields (U.S. Department of Energy, 1999). Our review indicates that recent reserve additions in south-central Wyoming have come from old fields. In the large areal fields of the Great Divide and Washakie basins and on the Wamsutter Arch (Figure 2), production sweet spots are searched for when evaluating additional anomalously pressured gas targets. Surdam et al. (2001) suggested that elements needed to evaluate these types of potential anomalously pressured gas prospects are:

- gas distribution
- gas migration conduits
- reservoir gas content
- micro fracture swarm distribution
- linear fault orientation
- reservoir characterization attributes.

U.S. Department of Energy (1999) also reports that new reserve additions come from more intensive development within the limits of known reservoirs. Our review shows that this is occurring at Echo Springs, Standard Draw, and Wild Rose fields (Figure 2). Horn and Schrooten (2001) showed that infill drilling of 25 wells in these fields "increased the recovery efficiency and doubled the recoverable reserves from the reservoir horizons in the Almond Formation." The subject infill drilling occurred during the October 1998 to September 1999 period. The 25 wells were drilled as third and fourth wells (development went from 320-acre spacing to 160-acre spacing) in the studied sections. Since that time, the Wyoming Oil and Gas Conservation Commission has approved fifth and sixth wells, in some 640-acre sections, in the Standard Draw Field. At the Echo Springs and Wild Rose fields they have approved fifth wells in some 640-acre sections.

The oil and gas recovery process in a field may occur in the following sequence:

- <u>Primary Recovery</u> - Primary recovery produces oil, gas, and/or water using the natural pressure in the reservoir. Wells may be stimulated to improve the flow of oil and gas to the borehole. Other techniques, including artificial lift, pumping, and gas lift, help continue production when a reservoir's natural pressure dissipates.
- <u>Secondary Recovery</u> – Secondary recovery uses methods like gas reinjection to maintain reservoir pressure and boost primary production, water flooding to energize the reservoir and displace hydrocarbons not produced in the primary recovery phase, or the first enhanced recovery method of any type applied to the reservoir to produce oil not recoverable by primary recovery methods. Enhanced oil recovery involves the injection of liquids or gases (surfactants, polymers, or carbon dioxide) or sources of heat (steam or hot water) to stimulate hydrocarbon flow and move hydrocarbons that were bypassed in earlier recovery phases.

Secondary oil recovery projects are initiated because of limited production efficiency of primary recovery and water-flood projects (Williams and Pitts, 1997). Primary depletion in most Rocky Mountain reservoirs is only 10 to 20 percent. They reported that locale can be important in enhancing oil recovery projects. For example, proximity to a carbon dioxide source is a factor in choosing a carbon dioxide project. A source of fresh or treatable water is needed for steam-flood or chemical projects. Accessibility of cheap natural gas is a consideration for gas injection projects. Oil and gas prices play a very important role in determining whether an enhanced oil recovery project is viable, and deciding the type of recovery project that would be suitable.

In 2002, there was one active gas injection project within the Field Office area, at the Wertz Field, just east of Lost Soldier Field (Wyoming Oil and Gas Conservation Commission, 2003b). Gas injection projects are used to maintain reservoir pressures or to aid in secondary recovery of oil or for enhanced oil recovery. Merit Energy Company operates an alternating gas and water flood to recover additional oil from the Cambrian Flathead Sandstone at Wertz Field. It was initiated in 1998. No air injection or hydrothermal injection projects are active in the Field Office area.

Merit Energy Company is operating tertiary recovery projects at Lost Soldier and Wertz fields (Wyoming Oil and Gas Conservation Commission, 2003b). Injected formations in both fields are the Tensleep, Madison, and Darwin. Water and carbon dioxide are presently being injected to enhance oil recovery. These projects have been active since 1985.

Water is used in six active secondary oil recovery projects (Wyoming Oil and Gas Conservation Commission, 2003b). Two projects lie in the Denver-Cheyenne Basin (Figure 2). Duncan Oil, Inc., operates a Muddy Sandstone injection project at Chivington Field (township 16 north, range 62 west) that was approved in 1994. Corral Production Corporation also operates a Muddy Sandstone injection project. It is at Horse Creek Unit (townships 16 and 17 north, range 68 west). This project was approved in 1962.

Three projects lie in the Laramie Basin (Figure 2). Rock River Operating Inc., operates a Lakota Formation injection project at the Diamond Ranch Unit on the northwest edge of the basin (township 20 north, range 78 west). That project was approved in 1977. They also operate two projects at Rock River Field (township 19 north, range 78 west). Muddy Sandstone injection was approved in 1962 and Muddy-Dakota-Lakota formation injection was approved in 1973.

On the northeast edge of the Great Divide Basin (township 26 north, range 88 west), lies the sixth injection project. Wold Oil Properties operates the Mahoney Dome Field injection project, which injects into the Tensleep Sandstone. This project was approved in 1983.

Acid Gas Removal and Recovery

Before natural gas can be transported safely, any hydrogen sulfide or carbon dioxide gas must be removed. Special plants are needed to recover the unwanted gases and sweeten gas for sale. Improvements in the process have made it possible to produce sour natural gas resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. Hydrogen sulfide is produced in some of the older oil producing formations. Fields known to produce hydrogen sulfide within the Field Office are:

- Lost Soldier and Wertz fields on the northeast edge of the Great Divide Basin (Figure 2)
- Table Rock Field on the west-center edge of the Field Office
- Quealy and Herrick fields in the Laramie Basin.

Artificial Lift Optimization

Artificial lift is used to produce oil once reservoir pressure declines and natural processes can no longer push the oil to the surface. Improvements have enhanced production, lowered costs, and lowered power consumption, which reduce air emissions. Artificial lift is used to recover oil from some of the older fields in the Field Office area.

Glycol Dehydration

Dehydration systems use Glycol to remove water from wet natural gas before the gas can be directed to a pipeline. During operation, these dehydration systems may vent methane, other volatile organic compounds, and hazardous air pollutants. Improvements to these systems have allowed increased gas recovery and have reduced unwanted emissions.

Freeze-Thaw/Evaporation

In southwestern Wyoming a new freeze-thaw/evaporation process has been shown to be useful in separating out dissolved solids, metals, and chemicals that are contained in water produced along with the oil and gas production of wells. In 1998, this type of produced water facility was constructed for McMurray Oil Company at Jonah Field (PTTC, 2002) northwest of the Field Office area. Over the first winter season (1998/1999), 17,300 barrels of water with a total dissolved solids content of 22,800 milligrams per liter was treated at this facility. The process yielded 9,500 barrels of treated water and 5,900 barrels of brine solution (1,900 barrels of water were lost to evaporation and sublimation). The treated water (1,210 milligrams per liter dissolved solids content) was suitable for reuse in drilling operations in the near-surface portion of other boreholes. The brine (66,900 milligrams per liter dissolved solids content) was suitable for reuse in drilling the deeper portions of other boreholes in the area. In each of the two following years progressively greater amounts of treated water have been produced at this facility. This process is being used to process produced water from numerous wells in the Great Divide Basin. In the future, use of this technique could spread to other parts of the Field Office area.

Leak Detection and Low-bleed Equipment

New technology is facilitating the detection of hydrocarbon leaks in equipment. The replacement of equipment that bleeds significant gas allows for increased worker safety and reduced emissions of methane. Not allowing gas to bleed from equipment increases recovery rates and usage of this valuable resource.

Downhole Oil/Water Separation

At least some water is produced along with the hydrocarbons in most wells within the Field Office area. It is most often stored, at least temporarily, in dug pits. Small amounts of water may be allowed to evaporate or percolate into the subsoil. It may be trucked to larger approved disposal pits, or it may be injected into approved subsurface zones. Emerging technology to separate oil and water could cut produced water volumes by as much as 97 percent in applicable wells (U.S. Department of Energy, 1999). By separating the oil and water in the borehole and injecting the water directly into a subsurface zone, only the oil needs to be brought to the surface. This new technology could help to minimize environmental risks associated with bringing water to the surface where it then has to be handled, treated, and then disposed of. It would also reduce the costs of lifting and disposing of produced water. In addition, surface disturbance could be reduced, oil production could be enhanced, and marginal or otherwise uneconomic wells could become economic.

Vapor Recovery Units

Vapor recovery can reduce a lot of the fugitive hydrocarbon emissions that vaporize from crude oil storage tanks, mainly from tanks associated with high-pressure reservoirs, high vapor releases, and large operations. The emissions usually consist of 40 to 60 percent methane, along with other volatile organic compounds, and hazardous air pollutants (U.S. Department of Energy, 1999). Where useable, this technology can capture over 95 percent of these emissions.

Site Restoration

Industry is turning to flexible Risk-Based Corrective Action as a process to ensure swift, efficient clean up of abandoned producing well sites and to restore these sites to near-original conditions. They are also using soil bioremediation and wetlands restoration to restore sites.

UNDERGROUND GAS STORAGE

Produced gas can be stored in some existing good quality reservoirs that have already been depleted of their native gas content. The objective of gas storage is to allow lands to be used to store natural gas during periods of excess production so that those supplies can be made available to meet peak gas demands and to maximize the efficiency of the gas delivery system. Kinder Morgan operates two active gas storage projects within the Field Office area. They are:

- Mahoney Dome East Field – located between Great Divide and Hanna basins (township 26 north, range 87 west), stored in the Dakota-Sundance-Muddy, and approved in 1974
- Oil Springs Field – located just east of Hanna Basin (township 23 north, range 79 west), stored in the Dakota-Lakota-Sundance, and approved in 1951.

The Tensleep Sandstone has also been used for underground gas storage at Wertz Field/Unit. Wertz Field/Unit lies adjacent to and east of Lost Soldier Field (Figure 2). It is currently inactive, but could be reactivated if additional gas storage capacity in the area is needed. At present, there are no proposals for additional underground gas storage in the Field Office area.

ASSESSMENTS OF OIL AND GAS RESOURCES

"The importance of natural gas as a primary energy source in the United States has grown considerably during the past decade" (Curtis and Montgomery, 2002). Rising demand in this country has resulted in a 22 percent increase in our consumption between 1990 and 2000. During that period consumption rose from 18.7 to 22.8 trillion cubic feet (Energy Information Administration, 2001). Our domestic production only rose from 17.7 to 19.7 trillion cubic feet (11.3 percent) for that period (Curtis and Montgomery, 2002). This gap between consumption and production has necessitated a rise in imports and concern about our future United States energy supply.

Significant amounts of oil and gas have been produced within the Rawlins Field Office area to date, which helps supply a portion of this countries demand. The Field Office area also has significant potential for continuing to help meet rising national demand by supplying additional oil and gas that has not yet been discovered. A number of recent oil and gas resource assessments have been prepared that cover all or portions of the Field Office area. These assessments provide an indication of the range of undiscovered resource volumes that could be available for exploration, development, and production through the year 2020.

We will present below the results of a number of oil and gas resource assessments as they relate to the Field Office area. A discussion of recent gas-in-place estimates will be presented first, and will then be followed by estimates available for proved oil and gas reserves. Some estimates only describe potential gas resources since only relatively minor amounts of undiscovered oil are thought to be present in the region when compared to the potential gas resource. For example, no recent estimates of oil-in-place were available.

Finally, we will review recoverable resource estimates that have recently been made by the U.S. Geological Survey, the Department of Energy via sponsored work, and the Potential Gas Committee. The Department of Energy sponsored estimates significantly exceed estimates made by the U.S. Geological Survey. Those differences are a result of alternative methodologies used, dissimilar assumptions made, and the use of different geologic models that were designed to serve different analysis purposes. The Potential Gas Committee also uses different methods and assumptions to make a prediction of potential resources, and we present it as an additional estimate of resources. Combined, these studies provide an idea of the range of oil and gas resources that may be available for exploration and development through 2020.

GAS-IN-PLACE ESTIMATES

Gas-in-place (see Glossary definition for *in-place*) estimates attempt to describe the gas resource in an area without considering its economic or technical viability (Boswell et al., 2002a). Our review of additional resource estimates (see sections immediately following this discussion of gas-in-place estimates) will take the next step and attempt to determine what portion of the gas-in-place resource is proved and what portion is technically and economically recoverable.

Within the region, gas-in-place studies have been prepared for the Greater Green River Basin as a whole. The Greater Green River Basin covers only approximately the western one third of the Field Office area, where most of the recent activity has occurred. Law et al. (1989) studied overpressured low-permeability Cretaceous and Lower Tertiary aged reservoirs in the basin. Five plays were assessed (Cloverly-Frontier, Mesaverde, Lewis, Fox Hills-Lance, and Fort Union). The reservoirs in these five plays produce the bulk of the basin's gas. They estimated that a mean gas-in-place volume of 5,063 trillion cubic feet could be present in these reservoirs in an area of about 12,608,000 acres. Law et al. (1989) found that two-thirds of this volume was contained within the various formations that make up the Mesaverde play. Assuming that the total resource is evenly distributed across the Greater Green River Basin, about 1,253 trillion cubic feet of gas-in-place could be present in the analyzed reservoirs within the Field Office area. The U.S. Geological Survey provided support for the subject analysis. It highlighted the concept and importance of basin-center gas formations and provided the data and information that the oil and gas industry could use to explore and develop these types of overpressured, low – permeability reservoirs. They also increased awareness of the very large volumes of gas existing in the Greater Green River and other basins.

The more recent review of Caldwell (1997) also studied Cretaceous and Tertiary aged tight gas formations in the Greater Green River Basin area. That review (sponsored by the Department of Energy) estimated that a mean gas-in-place volume of 1,968 trillion cubic feet could be present in these reservoirs. This study used a similar approach to that of Law et al. (1989), but added analysis of well logs to obtain more detail on typical porosity and water content within the potential reservoirs of each play. That additional data resulted in the lower gas-in-place estimate. Again, assuming that the resource is evenly distributed across the Greater Green River Basin, their data indicate that about 487 trillion cubic feet of gas-in-place could be present in these reservoirs within the Field Office area.

The most recent review (Boswell et al., 2002b) studied only certain of the most productive Cretaceous aged formations within the Greater Green River Basin area. That review (sponsored by the Department of Energy) updated the estimated gas-in-place that could be present in the seven units they analyzed. Seven analyzed units lie at least partly within the Field Office area (Figure A1-1). They determined that 3,638 trillion cubic feet of gas-in-place could be present in the seven units. Assuming an even distribution of resources within each analyzed unit, about 1,051.6 trillion cubic feet of gas-in-place could be present in these reservoirs within the Field Office area (Figure A2-1).

Boswell et al., (2002b) determined that reservoirs below 15, 000 feet contain some of the predicted 3,638 trillion cubic feet of gas-in-place. They projected that about 595.7 trillion cubic feet of that gas-in-place volume occurs below 15,000 feet. Of the projected deep gas, we determined that about 141.8 trillion cubic feet of gas-in-place could be present within the Field Office area. A more complete discussion of the Boswell et al., (2002b) assessment is presented in Appendix 1.

The studies cited above have determined gas-in-place volumes for portions of the potential gas bearing units known to lie within the Greater Green River Basin. No projections for areas to the east were found. Cretaceous aged units have been studied most intensely, because they are thought to contain the largest portion of the potential gas-in-place resource in the region.

PROVED OIL AND GAS RESERVES

The only known recent attempts to estimate proved oil and gas reserves for areas covering the Field Office region were; a report prepared by the U.S. Departments of the Interior, Agriculture, and Energy (Cantey et al., 2003), and a U.S. Geological Survey report (2003c). The first report was prepared in compliance with the Energy Policy and Conservation Act amendments of 2000. In that report, the Energy Information Administration provided a detailed description of methods used to calculate proved oil and gas reserve estimates for the entire Greater Green River Basin, and for other western regions. The Greater Green River Basin occupies a large part, but not all of the Field Office area. Energy Information Administration detailed analysis of available data indicated that the Greater Green River Basin contains 177.362 million barrels of liquid reserves (both oil and natural gas liquids) and 10.082 trillion cubic feet of gas reserves. The Field Office area occupies almost 21 percent of the Greater Green River Basin area. If the proved oil and gas reserves estimated by the Energy Information Administration are assumed to be evenly distributed across the basin, then about 36.59 million barrels of proved liquid reserves and 2.08 trillion cubic feet of proved gas reserves lay within the Field Office area.

The second report was prepared by the U.S. Geological Survey (2003c). This report was prepared for the Denver Basin Province as part of their ongoing “National Oil and Gas Resource Assessment.” Proved reserves (cumulative production plus remaining reserves) were estimated for only two assessment units (Dakota Group and D Sandstone assessment unit and Permian-Pennsylvanian Reservoirs assessment unit; see appendix two for additional discussion of these assessment units) of the seven that lie at least partly within the Field Office area. If the proved oil and gas reserves estimated by the U.S. Geological Survey are assumed to be evenly distributed across the basin, then about 48.88 million barrels of proved liquid reserves and 60.36 billion cubic feet of proved gas reserves lay within the Field Office area. We estimate that the Greater Green River Basin and Denver Basin Province contain at total of **85.47 million barrels of proved liquid reserves and 2.14 trillion cubic feet of proved gas reserves**.

The above studies did not include an estimation of any proved reserves for that part of the Southwestern Wyoming Province east of the Greater Green River Basin and west of the Denver Basin Province. Of the two Southwestern Wyoming Province plays identified by the U.S. Geological Survey that lie partly within this area (see Appendix 2), only the platform play contains productive hydrocarbons. Some of Wyoming's oldest fields are located within this play area. If an estimate of proved reserves were available, the above proved reserve estimate would be significantly increased for liquid reserves, and less so for gas reserves.

U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS

Law et al. (1989) studied overpressured low-permeability Cretaceous and Tertiary aged reservoirs in the Greater Green River Basin. They estimated that recoverable gas in the reservoirs studied ranged from 189 to 816 trillion cubic feet, with 433 trillion cubic feet as the mean estimate. Assuming that the resource is evenly distributed across the Greater Green River Basin, a range of 39 to 168 trillion cubic feet, with a mean estimate of 88 trillion cubic feet could be present in these reservoirs within the Field Office area.

The U.S. Geological Survey in their newer assessment studies have attempted to make estimates of resources for all potential oil and gas bearing units in the region of the Field Office. They have published three assessments of undiscovered oil and gas resources that cover parts of the Pinedale Field Office area. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) presents information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Two of those provinces, the Southwestern Wyoming and Denver Basin provinces, lie partly within the Field Office area. Recently the U.S. Geological Survey published the "Assessment of Undiscovered Oil and Gas Resources of the Southwestern Wyoming Province, 2002" (2002 and 2003b) and the "2002 USGS Assessment of Oil and Gas Resource Potential of the Denver Basin Province of Colorado, Kansas, Nebraska, South Dakota, and Wyoming" (2003a and 2003c) to update their quantitative estimate of the undiscovered oil and gas resources for these provinces. A more complete discussion of these assessments, their locations, and estimates of the oil and gas resource volumes; is presented in Appendix 2.

For the Southwestern Wyoming and Denver Basin province assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition) for each play or assessment unit (Tables A2-3 and A2-6). When preparing estimates of resource quantities for the play areas in the Southwestern Wyoming Province, the U.S. Geological Survey assumed that those resource quantities would be producible using current recovery technology but they did not consider the economic viability of those estimated resources, nor the length of time it would take for those resources to be discovered. For the assessment units in the newer Southwestern Wyoming and Denver Basin provinces, the U.S. Geological Survey used geology-based, well-documented estimates of quantities of oil and gas having the potential to be added to reserves within a future time frame—forecast span—of 30 years.

For each type of hydrocarbon, a mean estimated undiscovered resource volume was recorded for each assessment unit or play and a calculation of the portion lying within the Field Office area was made (Tables A2-3 and A2-6). We estimate that all play or assessment units lying within the Field Office area contain a mean undiscovered volume of **55.60 million barrels of oil, 30.511 trillion cubic feet of gas, and 748.01 million barrels of natural gas liquids**.

In addition, we estimate that the Field Office area's oil resource could range from 27.17 to 109.05 million barrels, the gas resource could range from 20.109 to 44.277 trillion cubic feet, and the natural gas liquids resource could range from 391.2 to 1,271.55 million barrels.

DEPARTMENT OF ENERGY SPONSORED RESOURCE ASSESSMENTS

The Department of Energy has sponsored three resource assessments of the Greater Green River Basin area in recent years. Only potential for gas was studied in each of these assessments.

Caldwell Assessment

Caldwell (1997) studied Cretaceous and Tertiary aged tight gas formations in the Greater Green River Basin area. He determined that 608 trillion cubic feet of this potential gas resource was available for conversion to reserves that could be produced in the future; within no forecast span used. Assuming that the resource is evenly distributed across the Greater Green River Basin, about 125 trillion cubic feet of gas could be present in these potential reservoirs within the Field Office area.

Advanced Resources International Assessment

Advanced Resources International (2001) prepared an analysis of the gas resource in southern Wyoming and northwestern Colorado and focused on the Greater Green River Basin and adjacent areas. This analysis was part of a larger project planned by the Department of Energy. Advanced Resources International used the U.S. Geological Survey's 1995 assessment, supplemented by data from the Wyoming State Geologic Survey, and their own work, to estimate undiscovered, technically recoverable, natural gas resources for the area studied. They did not evaluate proved gas reserves or oil resources.

For all U.S. Geological Survey plays, Advanced Resources International assumed a homogenous distribution of resource within play boundaries. Using the three sources of data listed above, they predicted the undiscovered, technically recoverable, gas resource for the entire study area and for each township. Their results showed that there is about 160 trillion cubic feet of potential natural gas resources in the study area. The total predicted gas resource in the Field Office area is **47 trillion cubic feet**. Advanced

Resources Internationals resource prediction is more optimistic than that of the U.S. Geological Survey mean value of 30.511 trillion cubic feet of gas.

The gas resource analysis of Advanced Resources International (2001) was used to produce Figure 11. That figure shows Field Office area undiscovered, technically recoverable, gas resources by township. Three gas resource volume ranges are shown on Figure 11, as well as townships where a zero gas resource is predicted. Townships with zero gas resource are located in areas of mountain ranges that are made up of Precambrian igneous and metamorphic rocks, where traps and gas resources are not known to occur. The highest predicted volumes of gas (500 billion to three trillion cubic feet of gas per township) are located in townships scattered across parts of the eastern Washakie Basin, Wamsutter Arch, and eastern Great Divide Basin. Mid-range predicted volumes of gas (50 billion to 499.999 billion cubic feet of gas per township) are located in the rest of the Washakie and Great Divide basins, and in most of the Hanna Basin. Hanna Basin coalbed gas resource estimates, made by the Wyoming Geological Survey, account for a part of the predicted mid-range volumes for that area. The Denver Basin Province, in the easternmost part of the Field Office area, is predicted to contain only low volumes of undiscovered gas. Almost all the "Atlantic Rim" proposed coalbed gas project area lies in the low volume prediction area, along the easternmost margin of the Washakie Basin. Low volume predictions in some parts of the Field Office area (e.g. Lost Soldier Field) were made where much of the potential gas resource has already been discovered and is being produced.

EG&G Services, Inc. and Advanced Resources International Assessment

The report by Boswell et al. (2003b), attempts to provide a better understanding of the size and nature of gas resources in the Greater Green River Basin and the potential of technology to convert those resources into economically recoverable resources. The study only reviewed the Cretaceous section in the Greater Green River Basin, which encompasses most of the basin's gas resources. A more complete discussion of this assessment, locations of units analyzed, data acquisition methods, analysis techniques, and estimates of gas resource volumes; is presented in Appendix 1.

Using the report of Boswell et al (2003b), we were able to estimate that about 108.88 trillion cubic feet of technically recoverable gas, might be contained within the Field Office area. This is significantly higher than the U.S. Geological Survey prediction of 30.484 trillion cubic feet of gas for the new Southwestern Wyoming Province assessment, which covers the same area as the Greater Green River Basin (see Appendix 2 for additional information on the U.S. Geological Survey study). Analysis differences stem from the use of alternative methodologies, different geologic models, and different assumptions. For example, the U.S. Geological Survey estimates for continuous-type assessment units are based on extrapolating past production history to the assessment unit's remaining untested regions and therefore, is influenced by past economic decisions of operators. The Boswell et al. (2003b) assessment of technically recoverable resources is based on the reservoir geology modeled with current technology and assuming full resource development. In addition, the U.S. Geological Survey limits their analysis to a

30-year forecast span. Boswell et al. (2003b) do not place a time limit for discovery on their analysis. Thus, they can allow for additional discoveries to occur beyond the 30-year period.

None of the Field Office areas to the east of the Greater Green River Basin were reviewed for the Boswell et al (2003b) assessment.

POTENTIAL GAS COMMITTEE ASSESSMENT

The Potential Gas Committee (2003) estimates only gas volumes that can be expected to be producible in the future, with reasonable future prices and technological advances. Resource volumes estimated are probable (roughly equivalent to the concept of reserve growth, see Glossary definition), possible (not associated with known oil and gas fields, but in favorable areas), and speculative (in formations or areas that are not now productive) categories. Potential Gas Committee methodology uses expert estimates of the volume of potential reservoir rock, multiplying that volume by an expected yield, and then discounting the resulting volume for geologic risk. The committee lumps all types of gas resources (tight-gas and conventional) into one category called traditional resources. They did make a separate estimate for gas below 15,000 feet and for coalbed gas resources.

The Potential Gas Committee (2003) estimated that the most likely resource for the Greater Green River Basin, Hanna-Laramie Basin area was 18.454 trillion cubic feet of gas from 0 to a 15,000-foot depth and 8.359 trillion cubic feet of gas for depths below 15,000 feet. We estimate that the Field Office area occupies less than 30 percent of the Greater Green River Basin, Hanna-Laramie Basin region defined by the Potential Gas Committee. If our estimate is accurate, then the resource estimates listed above would need to be reduced by at least 70 percent to represent the total resource that may be present in the Field Office area in each category. We do not have digital information available to make a more accurate estimate of the portion of each resource, predicted by the Potential Gas Committee (2003), which may be located within the Field Office area.

In the Potential Gas Committee (2003) estimate for the Denver Basin, Chadron Arch, Las Animas Arch area, they projected 2.437 trillion cubic feet of gas from 0 to a 15,000-foot depth. They also projected that no gas was recoverable below 15,000 feet in this area. We estimate that the Field Office area occupies less than five percent of the Denver Basin, Chadron Arch, and Las Animas Arch area defined by the Potential Gas Committee (2003). If our estimate is accurate, then the resource estimates for this area would need to be reduced by at least 95 percent to represent the total resource that may be present in the Field Office area. The gas resource left to find in this part of the Field Office would be relatively minor in comparison to westernmost portions of the Field Office area.

The Potential Gas Committee (2003) estimate of most likely coalbed gas resources for the Hanna-Carbon Coal Fields (this area lies entirely within the Field Office) is 6.138 trillion cubic feet. Their estimate for the Green River Coal Region, Wyoming Thrust Belt areas is 2.500 trillion cubic feet of gas. We estimate that the Field Office area occupies about 30 percent of the Green River Coal Region, Wyoming Thrust Belt coal area. If our 30 percent estimate is accurate, then the Potential Gas Committee (2003) coalbed gas resource estimate for the Green River Coal Region, Wyoming Thrust Belt areas needs to be reduced by about 70 percent to represent the total resource that may be present within the Field Office area.

OIL AND GAS OCCURRENCE POTENTIAL

We consider that most of the Rawlins Field Office area has a high potential for the occurrence of oil and gas (Figure 12). This rating considers a variety of geologic characteristics, including:

- presence of hydrocarbon source rocks
- presence of reservoir rocks with adequate porosity/permeability
- potential for structural/stratigraphic traps to exist
- opportunity for migration from source to trap
- other conditions; such as temperature, depth of burial, and subsurface pressures.

All oil and gas play areas and assessment units, as defined by the U.S. Geological Survey, are considered as being in areas of high occurrence potential. Approximately 77 percent of the Field Office area falls within this category.

Approximately 23 percent of the Field Office area falls outside of play areas or assessment units designated by the U.S. Geological Survey. These areas are mostly located in parts of mountain ranges that are made up of Precambrian igneous and metamorphic rock; where traps, reservoir strata, and hydrocarbons are not known to occur.

PROJECTIONS OF FUTURE ACTIVITY 2001-2020

OIL AND GAS PRICE ESTIMATES

Anticipated oil and gas prices are the single most important factor controlling the amount of future oil and gas drilling and production activity in the Pinedale Field Office area. These prices can be very volatile as shown for gas in Figure 13 and for oil in Figure 14.

Gas prices to 2025 (Figure 13) were estimated based on annual historical spot gas prices at Opal, Wyoming and the estimated gas price for the year 2025 as reported by the Energy Information Administration, (2003, page 75). The New York Mercantile Exchange (NYMEX) futures prices are from the Enerfax Daily web site (www.enerfax.com). Historical prices are in nominal dollars and projected prices are in 2001 dollars. In order to estimate prices for Wyoming natural gas, a differential must be subtracted from both the NYMEX futures and the Energy Information Administration estimated prices. This differential generally reflects transportation costs. A differential of $0.75/MMBTU was used to adjust the NYMEX futures to a Wyoming price. In addition, the estimated cost of liquefied natural gas delivered to the east coast of the U.S.

is about $1.75 to $2.75/MMBTU (Cook, personal communication). Other estimates suggest $3.50/MMBTU. If these estimates prove to be accurate, long-term prices for Wyoming will probably not be in excess of about $3.00/MMBTU. Based on the estimates used, annual Wyoming spot gas prices will probably be near the maximum for the planning period during the next few years and prices, in constant dollars, at the end of the planning period will be no higher than current prices.

These price estimates allow some generalizations concerning future gas drilling and production activity in the Pinedale Field Office area. If the gas price scenario explained above is accurate, future gas exploration and production will be a function of continuing price increases only during the next few years. Gas prices may then begin a time of no increases, similar to the 1985-1995 period (Figure 13). If prices do stabilize, it should be substantially above the 1985-1995 level. Future gas production in southwest Wyoming will be mainly a function of the ability of industry to discover and economically develop new gas accumulations, and the ability to increase drilling, production, processing, and transportation efficiency.

U.S. demand for natural gas is expected to increase about 50 percent by 2020. Increase in future natural gas production is projected to come from the Rocky Mountain area. These anticipated production increases are expected to be mainly from unconventional energy sources such as coalbed gas and deep basin centered gas deposits. Also, natural gas imports, especially liquefied natural gas, will meet much of the anticipated demand increase and will substantially influence the price of natural gas.

Anticipated oil prices are also based on historical crude oil prices and Energy Information Administration (2003) estimates. Figure 14 shows historical oil prices, projections and the Energy Information Administration (2003) estimated oil prices for 2025. The Energy Information Administration estimated an average world oil price for 2025. Historically, the Energy Information Administration average world oil price is approximately equal to the Wyoming sweet crude oil price. Oil prices have been in the $22/barrel to $32/barrel range during the past 12 months. Futures prices suggest a steady decline to an average price of about $24/barrel during the next six years. The Energy Information Administration (2003, page 80) estimates the price of crude oil will be between $19/barrel and $32/barrel in 2025. It should be remembered that much of the world's crude oil comes form politically unstable areas. Occasional, unforeseen, and abrupt price increases should be expected. Based on historical oil prices, a period of higher oil prices than were experienced during 1986-1999 should be expected.

LEASING

After initial field work, research, and subsurface mapping (which frequently includes use of seismic data), leasing is often the next step in oil and gas development. Leasing may be based on speculation, with the most risky leases usually purchased for the lowest prices.

Leases on lands where the U.S. owns the oil and gas rights are offered via oral auction at least quarterly. Their maximum size is 2,560 acres and the minimum bid is $2.00 per acre. An administrative fee of $75.00 per parcel is charged and each successful bidder must meet citizenship and legal requirements. In addition to the lease bonus a $1.50/acre rental is charged for the first five years and $2.00/acre thereafter. Leases are issued for a ten-year term and a 12.5% royalty on production is required. Leases which become productive, are held by production and do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a "Pugh clause", which allows only the developed portion of the lease to be held by production. However, Federal leases have no such clause, allowing one well to hold an entire lease.

In Wyoming, Federal oil and gas lease sales are held on even numbered months, usually in Cheyenne, Wyoming. No lease sale was held in April 1996 due to the partial government shutdown. Since August 1996, only lands nominated by industry are offered for lease. Before that date virtually all Federal lands available for competitive leasing were offered at each sale. Each new lease contains restrictive stipulations which protect potentially affected, mainly surface, resource values.

Rawlins Field Office Area Leasing

In June 2003 there was a total of 2,220 Federal oil and gas leases covering a total of 1,951,448 acres leased for oil and gas in the Rawlins Field Office. The leased area covered by this RMP decision is 1,942,773 acres. Federal leased acreage is shown in Figure 15. In total, 43 percent of the Federal mineral estate covered in this RMP revision is leased for oil and gas. The majority of the leased Federal acreage is in western Carbon and eastern Sweetwater counties (Figure 15).

Federal oil and gas leases cover 8,675 acres with surface managed by the Bureau of Reclamation. There were no oil and gas leases in areas covered by National Forest lands. Twenty six percent of the leased Federal acreage is held by production, and therefore will not expire until the last well on the lease ceases production. The average size of Federal oil and gas leases is 879 acres. These figures are summarized in Table 5.

As Federal oil and gas leases expire the acreage may be nominated for leasing again. The number of Federal acres in the Rawlins Field Office area leased, on an annual basis, is shown in Figure 16. The amount of Federal acreage leased competitively from 1997 through 2001 has averaged 238 thousand acres per year and remained relatively constant. Eighty three percent of the acreage offered was leased competitively. From 1996 through 2001 over 1186 leases were issued for acreage in the Rawlins Field Office area. The average lease size was about 1034 acres.

The total amount of money received from bonus bids on Federal oil and gas leasing in the Rawlins Field Office from 1996 through 2002 was $29 million. This was 14 percent of all the lease bonus revenue received for Wyoming during 1996-002. The average bid was $28.96/acre, which is slightly higher than the overall Wyoming average of $22.79/acre. The largest per-acre bid was $875/acre for a 640 acre tract in T. 17 N., R.

94 W. The largest bonus bid was $841,940 for a 1,958 acre tract in T. 21 N., R. 93 W. Half of the bonus dollars came from just eight percent of the leased acreage. The amount received from bonus bids each year and the average dollar per-acre bid are shown in Figure 17.

Since virtually all of the acreage leased was public domain minerals, half of the bonus money went to the state of Wyoming. The other half stayed with the Federal treasury, where it was split between the conservation fund and the general fund on a 4:1 ratio respectively.

We estimate the amount of Federal oil and gas acreage under lease in the Rawlins Field Office area between 2000 and 2020 will range between 1.0 and 2.5 million acres. The amount of acreage held by production should increase substantially from the current 0.5 million acres. The amount of Federal acreage leased annually is projected to average between 70,000 and 190,000 acres, with the average bonus between $1.0 million and $5.5 million/year between 2004 and 2020. Gas prices and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. The average size of Federal leases will continue to be large, probably in excess of 900 acres. These projections indicate a minimum of $20 million will be received during the 20-year planning cycle. If Federal oil and gas leasing is similar to 1996-2002, approximately $81 million will be received in bonus payments during the 20-year planning cycle of 2001-2020, however this is a very optimistic scenario.

SEISMIC SURVEYS

Seismic surveys are a critical part of exploration for oil and gas resources. They are authorized on Bureau managed surface by approval of Notices of Intent to Conduct Geophysical Operations. Seismic surveys on surface not managed by the Bureau do not have to be permitted with the Bureau even though the surveys cover Federal minerals. The number of approved Notices of Intent to Conduct Geophysical Operations for the Rawlins Field Office from 1993 through 2001 is shown in Figure 18. The surveys were approximately evenly divided between those that used dynamite and those that used the vibroseis method to obtain data. About 40 percent of the seismic projects were 3-D surveys.

The number of seismic surveys on Bureau administered surface in the Rawlins Field Office is expected to remain at about the 1997-2002 level (average about five or six surveys per year) in the near term. As additional seismic data are acquired, the need for new data will decrease somewhat. The number of seismic surveys should decrease and be closer to the 1992-1996 (about one or two surveys per year) level during the second half of the planning cycle. Although several 2-D surveys will probably be run it is expected that most of the Notices of Intent to Conduct Geophysical Operations will be for 3-D surveys. Most will be located in eastern Sweetwater County or the far southwest part of Carbon County (eastern Greater Green River Basin). Some seismic surveys may be located in the east central part of Carbon County (Hanna and Laramie basin areas).

DRILLING OPERATIONS

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the Wyoming Oil and Gas Conservation Commission. If the well will be on Federal lands, an application to drill must also be approve by the Bureau. Not every approved Application for Permit to Drill is actually drilled. Since 1987 in the Rawlins Field Office area, about 70 percent of the approved Applications for Permit to Drill have actually been drilled. Federal wells have been about 44 percent of all wells drilled in the Rawlins Field Office area. Figure 19 shows the number of wells drilled per year in the Rawlins Field Office area since 1910. The graph does not include workovers, recompletions, or wells that were deepened. Records indicate that before 1910 only one well had been drilled. Note that there has been a pronounced upward trend in wells drilled.

As the number of wells drilled has increased the depth of the wells has also increased. From 1990-2001 the average depth of wells was 9,249 feet. Figure 20 shows the depth distribution for wells drilled during 1990-2001. A percentage was used because some wells did not have readily available depth information. Seventy four percent of the wells drilled were between 8,000 and 12,000 feet deep.

As additional wells are being drilled some wells are being plugged and abandoned. The great majority of these are wells which are either unproductive (dry holes), or have become depleted to the point of being uneconomic. Figure 21 shows the wells drilled and wells abandoned since 1980. Since 1980, the number of abandonments has been 37 percent of the total number of wells drilled. The number of abandoned wells may be slightly more than shown in Figure 21 because about 12 percent of the wells listed as abandoned did not have an associated date. The number of wells abandoned is more consistent year-to-year than the number of wells drilled.

Coalbed Gas Drilling

There has been considerable interest in coalbed gas drilling in the Rawlins Field Office area. The first coalbed gas wells were drilled in 1990 and some production was established. However, by August 1994 all wells had been shut in or abandoned. A second, more productive, phase of drilling started in 1999. Figure 22 shows the number of wells drilled in the Rawlins Field Office area. In 2001, alone 87 permits were approved and 55 were approved in 2002. Historically, 74 percent of the coalbed gas wells permitted have been drilled.

Results from coalbed gas pilot projects in Wyoming suggest that often too few wells have been drilled to adequately evaluate the economic viability of the area. Past history indicates that pilots should contain 16 (four interior wells) to 25 (nine interior wells) wells to adequately evaluate an area (Lance Cook, 2002, Wyoming State Geologist, personal communication, and Don Likwartz, 2002, Wyoming Oil and Gas Supervisor, personal communication). History suggests that fewer than 16 to 25 wells may not remove enough associated water to adequately reduce reservoir pressure over a sufficient area, so that gas can move toward the borehole. Also, heterogeneity in the coal may preclude the one interior well in a five or nine well pilot from providing the data necessary to adequately evaluate economic viability. It is recommended that coalbed gas pilots contain 16 to 25 wells. This should provide a better chance of obtaining adequate data and thus avoiding duplicate projects.

Projections of Future Drilling Activity

It is difficult to predict what will occur a few years into the future. It is very difficult to predict twenty years ahead. In an attempt to get more insight as to what may occur in the Rawlins Field Office area, geologists and engineers in the oil and gas industry were contacted. Twenty-three oil and gas companies which operate in the Rawlins Field Office area were contacted by letter and asked their opinion of what development activity will occur during the next twenty years. The Bureau contacted each company by telephone about five days after the letters were sent. Thirteen companies responded. Eight provided information useful in constructing the development potential maps. Some companies requested that the information provided be held confidential. Due to time constraints there was only a very limited review of technical data from wells in the Rawlins Field Office area by the authors of this report. Structure contour maps drawn by the Rocky Mountain Map Company were used as working base maps.

For a baseline, unconstrained Reasonable Foreseeable Development scenario (Federal Leadership Forum, 2002, page 13), we estimate that between 2001 and 2020 as many as 9,310 well locations may be drilled in the Rawlins Field Office area. These wells are expected to be about 50 percent conventional wells and 50 percent coalbed gas wells. The anticipated location of non-coalbed gas wells is shown on the Development Potential Map Figure 23. Much of the anticipated drilling activity will be infill wells in existing fields. High development potential indicates areas where the **average** drilling density will be greater than 100 wells per township (36 square miles) during 2001-2020. Moderate indicates 20 to 100 wells, low is defined as fewer than 20 wells, and very low is defined as fewer than two wells. In areas estimated to have no development potential, no wells are anticipated. Well depths for conventional wells will probably continue to increase as deeper reservoirs are developed. It is anticipated that approximately 30 wells will be deep wells (15,000 feet deep or greater).

If a viable coalbed gas play exists in the Rawlins Field Office area it is very early in the life of that play, and there is very little information currently available. Although there is very little development history, we used available information to estimate that as many as 4,425 well locations may be drilled between 2001 and 2020. Wells will probably be drilled on 80- or 160-acre patterns. Areas where we anticipate the greatest coalbed gas development are shown on the Coalbed Gas Development Potential Map, Figure 24. We expect that much of the Rawlins Field Office area will have little or no coalbed gas development. Wyoming Oil and Gas Conservation Commission records indicate coalbed gas wells as deep as 6,250 feet have been drilled in the Hanna Basin area in the Rawlins Field Office area. If economically productive, these wells would be some of the deepest coalbed gas producers in the western United States.

OIL AND GAS PRODUCTION

Non-Coalbed Gas

Natural gas production from wells on Federal, private, and state minerals is shown in Figure 25. Gas production was 7.5 times higher in 2001 than in 1974. Total gas production increased at a nominal rate of 4.2 percent per-year between 1986 and 1997, and 3.1 percent per-year between 1974 and 2001. The decline in production during 2000 and 2001 was mostly due to decline in production from private wells. Gas production from the Rawlins Field Office area in 2001 was 11 percent of Wyoming's total gas production.

Gas production is expected to continue increasing as short-term prices increase above the 2001 level. Production increases through 2020 are also expected however, long term prices will probably keep these increases to approximately historical levels or less. In other words it is unlikely that the production increase from 2001-2020 will be larger than production increases during the 1981-2001 time interval. It is expected that gas production will be between 150 BCFG/year and 350 BCFG/year by 2020.

Oil production from wells on Federal, private, and state minerals is shown in Figure 26. During 1984-1991 oil production was relatively stable. During 1990-2001 total oil production declined at a nominal rate of 2.8 percent per year. About half the crude oil produced in the Rawlins Field Office area during 2000 and 2001 was from the Lost Soldier-Wertz Field near Bairoil, Wyoming. In 2001 only seven percent of Wyoming's total oil production came from the Rawlins Field Office area.

It is anticipated that oil production will continue declining. The rate of decline is expected to be less however as condensate production from gas wells becomes an increasingly larger proportion of the oil produced from the Rawlins Filed Office area. The Lost Soldier-Wertz Field will continue to produce proportionally less of the total oil. Although the overall trend is expected to be downward during 2001-2020, there will probably be some year-to-year increases in oil production.

The number of producing wells in the Rawlins Field Office area increased at a nominal rate of 3.1 percent per year between 1974 and 2001. Figure 27 shows the number of producing wells in the Rawlins Field Office area from 1974-2001. The number of producing wells may increase substantially above this historical average as coalbed gas wells are drilled, in addition to conventional wells. We anticipate that the number of producing conventional wells will continue to increase at historical trends.

Coalbed Gas

In 2000 coalbed gas was about seven percent of total natural gas produced in the U.S. Coalbed gas is about 15 percent of total natural gas production in Wyoming. It has been estimated that future increases in natural gas production in Wyoming will be mostly from coalbed gas (Cook, 2002, personal communication). If this is so, then the number of coalbed gas wells will need to continue to increase and new producing areas, such as the Hanna and Carbon basins and the eastern Washakie Basin in the Rawlins Field Office area will need to be developed.

Potential Gas Committee (2003, page 199) estimated recoverable coalbed gas resources in the Hanna-Carbon Basin alone to be 6 trillion cubic feet. This is 23 percent as much as the estimated recoverable coalbed gas resources in the Powder River Basin and 10 percent of the recoverable coalbed gas resources in the Rocky Mountain region and 3.6 percent of the entire U.S. including Alaska (Potential Gas Committee, 2003, pages 3 and 199). In addition there are extensive coalbed gas resources in the eastern greater Green River Basin which is also in the Rawlins Field Office area.

With the available data it is virtually impossible to predict whether or not coalbed gas will develop into a large gas play in the Rawlins Field Office area. Initial attempts to develop coalbed gas resources (1990-1994) were disappointing. When production ceased in August 1994, only 15 wells had been drilled and only 0.01 billion cubic feet of gas had been produced. Production began again in August 2000. Through July 2003 between 20 and 30 productive wells have been drilled and 1.0 billion cubic feet of coalbed gas has been produced. Production for all of 2003 is estimated to be approximately double the previous year, see Figure 28. This play is still quite speculative however, and development may ultimately be limited to localized areas, especially if long term gas prices prove to be less than anticipated.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

Extensive natural gas resources are almost certainly present in shales in the Rawlins Field Office area. A report by PACE Global Energy Services states “In addition, there are numerous carbonaceous shales in the GRB that are known to contain substantial gas resources that as of today have not been tested.” PACE Global also states “Carbonaceous shales are the most unexplored, and potentially largest, gas resources in the Rocky Mountain region.” (PACE Global Energy Services, 2003, page 28). These statements are clear. Carbonaceous shale is an important future source of natural gas. At present, technology and completion methods are not available to economically produce natural gas from shale. However, this important future natural gas source could become viable before the end of the planning cycle.

When and if technology and well completion methods are developed, this energy source will become significant. Initial development is expected to use existing boreholes. However, if sufficient reserves per well are present, additional wells may be drilled specifically to develop natural gas from shale. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas. This production may be accompanied by significant volumes of water. Well spacing may be dense; one well per 40 acres should be expected.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Field Office area. This process burns the coal and produces a low heating value gas that may be used in industrial processes and gas turbines. Air or oxygen commingled with steam is injected into the coal seam and burns the coal outward from the injection well. The combustion products react with the non-burned coal to form hydrogen, carbon monoxide and pyrolysis products that are produced at a production well. There is also evidence that combustion gases preferentially absorb to the coal cleat faces and displace coal bed methane gas from the coal, which would increase the heating value of the produced gas. The heat of reaction of the burned coal heats the unburned coal in front of the combustion front and drives off the hydrocarbon volatile matter contained in the coal. This volatile matter removal would be essentially the same process that coal goes through in the geologic process of changing lignite to anthracite by burial and geothermal heat. This geologic process is considered to be the source of much of the deep basin gas in the Almond Formation, which is located in the western part of the Field Office area.

Underground coal gasification is usually at depths too deep to be economically mined. Depth is a positive factor in the gasification process as the higher pressures at depth appear to give better reaction results and a higher heating value gas. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

In the Field Office area, underground coal gasification has been tested in the Shamrock Hills area and would be essentially the same injection/production process that is utilized in waterflooding oil reservoirs and in the carbon dioxide tertiary oil recovery process that is currently in progress at the Lost Soldier and Wertz oil fields. Because the coal is burned and removed, subsidence may be a problem but the thin zones, deep depths, and strong cap rocks should limit this. Currently this technology does not appear to be economic and as a result there is little activity in the state. Considering the relatively experimental status and abundant energy supplies from mineable coal in the Powder River Basin, there is a low probability that this process will be utilized in the next 20 years. However, if it becomes economic to remove volatiles from coal beds, then there could be development activity in the Rawlins Field Office area, particularly in the Hanna and Carbon basin areas. We estimate one or two pilot projects could be drilled by 2020.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas. It is a greenhouse gas that is generated by power plants, oil refineries, cement works, and iron and steel production. In Wyoming, a sizable volume of carbon dioxide is vented during the production of natural gas. Capturing and storing this gas has been proposed to reduce the environmental effects of this greenhouse gas. Currently, in the Rawlins Field Office area, carbon dioxide is being utilized in a tertiary oil recovery process whereby it is injected into an oil reservoir to adsorb into the interstitial oil, reducing the oil viscosity, and allowing increased recovery of the oil. This process also traps some of the carbon dioxide in the rock matrix as a free gas and in the interstitial water as dissolved carbon dioxide. The carbon dioxide used in this process currently comes from the Shute Creek processing plant to the west of the Field Office area and it would otherwise be vented. There are also large coal fired power plants in Wyoming that could be a concentrated source of this gas.

Carbon dioxide sequestration requires an oil reservoir that is isolated by an impermeable cap rock and has porosity and permeability characteristics that allow its efficient injection and storage. The reservoirs that are currently being flooded with carbon dioxide are very large, have good reservoir injection characteristics, and have proven to be isolated by an effective cap rock. After the current tertiary flooding project is completed, it would be reasonable to fill these reservoirs with carbon dioxide and sequester this greenhouse gas for geologic time. This process would also probably recover some extra oil as its saturation level would be reduced to the minimum by gravity segregation with the carbon dioxide gas. There are many more large geologic structures in the midsection of the Field Office area which have reservoirs at moderate depths with reservoir characteristics that would allow efficient storage of this gas. Some of these structures have reservoirs with limited oil reserves and sequestering carbon dioxide should improve the ultimate oil recovery from these fields. The environmental consequences of implementing this process would be much like the current tertiary oil recovery programs, except that only injection wells and compressors would be the necessary facilities. In the case where the gas is sequestered in an oil reservoir, additional oil recovery wells may be used to recover the gravity displaced oil. On a regional basis, this process would be an environmental benefit by reducing acid rain and increasing air quality.

REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS FOR RESOURCE MANAGEMENT PLAN ALTERNATIVES ONE, TWO, THREE, AND FOUR

The Environmental Impact Statement for the Rawlins Field Office Resource Management Plan contains four management alternatives. Each alternative contains management imposed restrictions that may negatively affect oil and gas development. These restrictions can effectively decrease the base line estimated number of well locations in areas of Federal oil and gas ownership. For each alternative, we have analyzed the restrictions and estimated the number of resulting well locations that could be reduced from the base line total. If restrictions for an alternative were determined to affect our base line projections of development potential, an additional development potential map was constructed.

PROCEDURES USED TO DETERMINE WELL LOCATION REDUCTIONS

Well location reductions from the base line reasonably foreseeable development scenario, for each alternative, are due to proposed management restrictions. Those restrictions can affect oil and gas development activities by not allowing leasing, not allowing surface occupancy, controlling surface use, or placing restrictive stipulations on conditions of approval of Federal applications to drill. For reasonably foreseeable development scenario analysis purposes the restrictions were separated into four categories designated A, B, C, and D. Restrictions on drilling are progressively more limiting from A to D and are:

- Category A restrictions are relatively minor and result in standard stipulations that are applied to every Federal oil and gas lease sold in Wyoming. They are considered to have no affect on the number of well locations for any alternative.
- Category B restrictions have a moderate effect such as multiple, consecutive timing restrictions for protection of crucial winter range, raptor nesting habitat, or sage grouse strutting grounds. Avoidance of areas within 500 feet of wetlands, riparian areas, or perennial waters is also considered to have a moderate effect on the potential locations of wells.
- Category C restrictions have a moderate to severe effect on the location of wells; such as no surface occupancy of areas 40 acres or less and requirements that view sheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails.
- Category D restrictions are severe restrictions on oil and gas activity and include proposals for no surface occupancy areas larger than 40 acres to protect certain identified resource values or withdrawing entire areas form oil and gas leasing.

Reductions in well locations from the base line reasonably foreseeable development scenario were determined as described below:

- An estimate of the number of well locations/township that could be drilled in each development potential category over the 20-year life of the Resource Management Plan was made for conventional oil and gas development activity (Table 6) and for coalbed gas development activity (Table 7).
- Conventional and coalbed gas development potential maps were overlain and 10 combinations of development potentials were identified (Table 8).
- The acres of Federal oil and gas ownership in each area were determined using GIS software. Acres of non-Federal oil and gas minerals were not included because proposed Resource Management Plan decisions will only apply to Federal oil and gas minerals. We assumed development on non-Federal minerals will occur as estimated in the base line foreseeable development scenario.
- Next, the area covered by each category of restriction (B, C, or D category) within the 10 development potential areas was calculated using GIS software. The area within category A was not calculated, since we previously determined that this type of restriction would have no affect on the number of well locations for any alternative. As an example, the Alternative 2 acreage calculations for each of these 10 areas are presented in Table 8.
- After the acres of Federal oil and gas were calculated for each alternative and each restriction category, the percent reduction in well locations for each alternative and each category of restriction was estimated. That estimate was a number agreed upon by the two authors and is based on best professional judgment. This estimate is a percent of the well locations which would not be

drilled in each area due to the specific category of restriction. As an example, the results of our calculations for conventional oil and gas under Alternative 1, Category C restrictions are shown in Table 9 below. The calculations were prepared using townships instead of acres, because well densities were listed in well locations per township for the 20-year planning cycle. The number of townships was calculated by dividing the Federal acres by 23,040 acres per township.

- The percent reduction for each alternative, each category of restriction, and each development potential combination was determined. Then the reduction in well locations was calculated and summed for each alternative for both conventional oil and gas and for coalbed gas. The results of these calculations are shown in Table 10.

The possible need to revise the base line development potential maps for non-coalbed gas development and coalbed gas development for the four alternatives was reviewed. Our review started with an analysis of well location densities using the information previously mentioned (Tables 6 and 7). Development potential had been assigned based on well locations per development potential category (see Table 11). If the development potential area was matched against the different category restrictions and it showed that a part of that development potential area had a reduced well density that would reduce the density to the next lowest potential area, then the potential map was modified to show the new development potential. Most category restrictions had only a minor affect on well densities. Well location densities usually decreased but generally not enough to cause the area to move to a lower development potential. Well reductions caused only the coalbed gas development map for Alternative 3 to change (Figure 29). Some parts of the coalbed gas high development potential area were reduced to moderate development potential for that map.

RESULTS

Since the base line reasonably foreseeable development scenario assumes no management constraints, each alternative is a reduction from the base line scenario. Table 10 above shows the estimated well locations for both non-coalbed oil and gas and coalbed gas wells for each alternative of the Rawlins Field Office area Resource Management Plan.

Development potential for non-coalbed oil and gas wells varies from about 4,168 well locations for Alternative 3 (the protection alternative) to 4,419 well locations for Alternative 2 (the development alternative). An estimate of continuation of current management would result in an estimated 4,295 well locations. For comparison, the base line estimate was 4,477 well locations. The estimated number of well locations for Alternative 4 (the preferred alternative) is 4,258.

Development potential for coalbed gas wells ranges from about 3,549 well locations for Alternative 3 (the protection alternative) to 4,779 well locations for Alternative 2 (the development alternative). The estimate for continued management is 4,652 well locations. The estimate for Alternative 4 (the preferred alternative) is 4,563 well locations. Restrictions on drilling, especially no surface occupancy restrictions, often have a disproportionate affect on coalbed gas wells. Often a critical number of coalbed gas wells are necessary to develop an area. If too few wells are drilled, reservoir pressure (water levels) cannot be adequately reduced to allow methane to desorb form the coal. When this happens either the amount of time needed to establish gas production is excessive, or pressure cannot be reduced adequately to determine if coalbed gas production is viable in the area.

In the Rawlins Field Office area directional drilling does not appear to be feasible on a large scale as a mitigation measure for restrictive conditions of approval of Federal applications to drill. Much of the drilling projected to be curtailed is for coalbed gas production, and the wells are, with few exceptions, not deep enough to allow directional drilling. Some conventional wells could be drilled directionally but the number of directional wells would not be large compared to the total number of estimated well locations.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

Projections of future oil (including condensate) and gas production by alternative and for the base line Reasonable Foreseeable Development scenario were prepared (Tables 12, 13, 14, and 15). Projections were obtained by using type wells, estimated well totals, and estimated decline rates for current producing areas. The Rawlins Field Office producing areas were divided into three parts and production estimates for each part were calculated. The three parts are:

- coalbed gas areas,
- oil and gas in townships 14 to 24 north and ranges 90 to 96 west (areas of current and future Almond Formation and Lewis Shale production), and
- oil and gas producing areas in the remainder of the field office.

Using historical drilling data, we estimated that 75 percent of the future conventional wells drilled would be in the Almond Formation and Lewis Shale area. Well totals for conventional and coalbed gas wells were estimated for each year in which future production was estimated. A summary of our production estimates is presented in Table 16.

SURFACE DISTURBANCE

Projections of drilling related surface disturbance are presented in Tables 17, 18, 19, and 20. These tables are modified from Chism (2004). In Table 17 he calculated gross disturbance for all new wells (Federal, state, and private) and all new Federal wells by:

- defining eight types of wells
- using new well number projections we had provided and noted as “RMG Projections” on the table and distributing them among the eight well types
- assigning a gross disturbance (in acres) for each type of well and associated road
- calculating total disturbance (in acres) for all wells and their associated roads

- calculating associated road only disturbance (in acres and miles)
- calculating the additional disturbance (in acres) due to pipeline activity
- calculating total acres disturbed by wells and their associated roads and by pipeline activity
- calculating the percentage of disturbance when compared to alternative 2 (the alternative with the largest projected amount of disturbance).

These steps were taken for each alternative for all new projected wells and since the four proposed Bureau actions are assumed to only affect the number of Federal wells that could be drilled (which in turn affects the amount of disturbance on Federal managed lands), they were also applied to all new Federal wells. Total disturbance due to the projected drilling of all new wells is estimated to range from 56,505 to 63,663 acres, with 57,819 acres disturbed for the Preferred Action (Alternative 4). Total disturbance from only new Federal wells is estimated to range from 21,015 to 28,261 acres, with 22,145 acres disturbed for the Preferred Action.

Table 18 calculated gross disturbances for all new wells plus existing wells (Federal, state, and private) and for all new Federal wells plus existing Federal wells. Existing well totals were obtained from the Wyoming Oil and Gas Conservation Commission (2003a) and were added to the new well totals. Acres of surface disturbance were then calculated in the same manner as previously described for Table 17. Total disturbance due to the projected drilling of all new wells plus existing wells is estimated to range from 91,581 to 99,492 acres, with 93,034 acres disturbed for the Preferred Action. Total disturbance from only new Federal plus existing Federal wells is estimated to range from 36,380 to 44,379 acres, with 37,630 acres disturbed for the Preferred Action.

Table 19 calculated net unreclaimed disturbances for all (Federal, state, and private) new wells minus new wells that will be abandoned. Net disturbance was calculated by:

- defining eight types of wells
- using new well number projections we had provided and noted as “RMG Projections” on the table and distributing them among the eight well types
- calculating the number of new wells that will be abandoned
- subtracting abandoned wells from new wells to determine net wells
- assigning a net unreclaimed disturbance (in acres) for each type of well and associated road
- calculating total unreclaimed disturbance (in acres) for all wells and their associated roads
- calculating unreclaimed associated road only disturbance (in acres)
- calculating the unreclaimed additional disturbance (in acres) due to pipeline activity
- calculating total acres of unreclaimed disturbed by wells and their associated roads and by pipeline activity
- calculating the percentage of unreclaimed disturbance when compared to alternative 2 (the alternative with the largest projected amount of disturbance).

These steps were taken for each alternative. Total unreclaimed disturbance due to the projected drilling of all new wells minus abandoned newly drilled wells is estimated to range from 15,472 to 17,013 acres, with 15,472 acres disturbed for the Preferred Action.

Table 20 calculated net unreclaimed disturbances for all (Federal, state, and private) new wells minus new wells that will be abandoned and minus old existing wells that may be abandoned. The "New Wells Abandoned" category for each alternative includes both abandoned new wells plus abandoned old existing wells. Acres of surface disturbance were then calculated in the same manner as previously described for Table 19. Total unreclaimed disturbance due to the projected drilling of all new wells minus abandoned newly drilled wells and minus abandoned old existing wells is estimated to range from 13,792 to 15,333 acres, with 13,792 acres disturbed for the Preferred Action.

Our projections of new wells drilled covered the period from 2001 through 2020. In his analysis of surface disturbance, Chism (2004) projected disturbance 20 years beyond October of 2003. Disturbance figures calculated for Table 17 are not affected by using this slightly different period of analysis. Tables 18, 19, and 20 would be slightly affected. A recalculation of the disturbance figures to the 2001 through 2020 period would slightly lower the disturbance figures obtained by Chism (2004).

SUMMARY

Our analysis technically analyzed the oil and gas resource occurring within the Field Office area, and projected future development potential and activity levels for the period 2001 through 2020. We analyzed a base line scenario and four management alternatives for the Environmental Impact Statement for the Rawlins Field Office Resource Management Plan. Each alternative contains management restrictions that may negatively affect oil and gas development. For each alternative, we analyzed the restrictions and estimated the number of well locations that could be reduced from the base line total.

GLOSSARY

Accumulation. An accumulation is one or more pools or reservoirs of petroleum that make up an individual production unit and is defined by trap, charge, and reservoir characteristics. Two types of accumulations are recognized, conventional and continuous.

Assessment unit. A mappable volume of rock within a total petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic traits and socio-economic factors. Accumulations within an assessment unit should constitute a sufficiently homogenous population such that the chosen methodology of resource assessment is applicable. A total petroleum system might equate to a single assessment unit. If necessary, a total petroleum system can be subdivided into two or more assessment units in order that each unit is sufficiently homogeneous to assess individually. An assessment unit may be identified as conventional, if it contains conventional accumulations, or as continuous, if it contains continuous accumulations.

Condensate. Liquid hydrocarbon recovered by separation from natural gas.

Continuous accumulation. Common geologic characteristics of a continuous accumulation include occurrence down dip from water-saturated rocks, lack of obvious trap and seal, pervasive oil or gas charge, large aerial extent, low matrix permeability, abnormal pressure (either high or low), and close association with source rocks. Common production characteristics include a large in-place petroleum volume, low recovery factor, absence of truly dry holes, dependence on fracture permeability, and sweet spots within the accumulation that have generally better production characteristics but where individual wells still have serendipitous hit or miss production characteristics (Schmoker, 2003).

Conventional accumulation. The U.S. Geological Survey has defined conventional accumulations "by two geologic characteristics: (1) they occupy limited, discrete volumes of rock bounded by traps, seals, and down-dip water contacts, and (2) they depend upon the buoyancy of oil or gas in water for their existence" (Schmoker and Klett, 2003).

Field. A production unit consisting of a collection of oil and gas pools that when projected to the surface form an approximately contiguous area that can be circumscribed.

Field growth. The increases in known petroleum volume that commonly occur as oil and gas fields are developed and produced; synonymous with reserve growth.

Gas accumulation. An accumulation with a gas to oil ratio of 20,000 cubic feet per barrel or greater.

Gas to oil ratio. The ratio of gas to oil (in cubic feet per barrel) in an accumulation. The gas to oil ratio is calculated using known gas and oil volumes at surface conditions.

Geologic province. A U.S. Geological Survey-defined area having characteristic dimensions of perhaps hundreds to thousands of kilometers encompassing a natural geologic entity (for example, sedimentary basin, thrust belt, delta) or some combination of contiguous geologic entities.

Grown petroleum volume. Known petroleum volume adjusted upward to account for future reserve growth. Thirty years of reserve growth is considered for the U.S. Geological Survey assessments.

In-place. The total volume of oil and/or gas thought to exist (both discovered and yet-to-be discovered) without regard to the ability to either access or produce it. Although the in-place resource is primarily a fixed, unchanging volume, the current understanding of that volume is continually changing as technology improves.

Known petroleum volume. The sum of cumulative production and remaining reserves as reported in the databases used in support of the U.S. Geological Survey assessment. Also called total recoverable volume (sometimes called ultimate recoverable reserves or estimated ultimate recovery).

Natural gas. Any gas of natural origin that consists primarily of hydrocarbon molecules producible from a borehole.

Natural gas liquids. Natural gas liquids are hydrocarbons found in natural gas that are liquefied at the surface in field facilities or in gas processing plants. Natural gas liquids are commonly reported separately from crude oil.

Oil accumulation. An accumulation with a gas to oil ratio of less than 20,000 (in cubic feet per barrel).

Petroleum. A collective term for oil, gas, natural gas liquids, and tar.

Play. A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play may differ from an assessment unit; an assessment unit can include one or more plays.

Proved reserves. The volume of oil and gas demonstrated, on the basis of geologic and engineering information, to be recoverable from known oil and gas reservoirs under present-day economic and technological conditions.

Reserve growth. The increases in known petroleum volume that commonly occur as oil and gas accumulations are developed and produced, synonymous with field growth.

Reserves. Oil and gas that has been proven by drilling and is available for profitable production.

Total petroleum system. The total petroleum system includes: 1) identification and mapping the extent of the major hydrocarbon source rocks; 2) understanding the thermal evolution of each source rock, the extent of mature source rock, and the timing of hydrocarbon generation, expulsion, and migration; 3) estimating migration pathways and all forms of hydrocarbon trapping; 4) modeling the timing of structural development and the timing of trap formation relative to hydrocarbon migration; 5) determining the sequence stratigraphic evolution of reservoirs, and the presence of conventional or continuous reservoirs, or both; and 6) modeling the burial history of the basin and the effect burial and uplift has had on the preservation of conventional and continuous hydrocarbons.

Undiscovered technically recoverable resource. A subset of the in-place resource hypothesized to exist on the basis of geologic knowledge, data on past discoveries, or theory, and that is contained in undiscovered accumulations outside of known fields. Estimated resource quantities are producible using current recovery technology but without reference to economic viability. These resources are therefore dynamic, constantly changing to reflect our increased understanding of both the in-place resource as well as the likely nature of future technology. Only accumulations greater than or equal to 1 million barrels of oil or 6 billion cubic feet of gas were included in the earlier 1995 assessment.

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APPENDIX 1 – EG&G SERVICES, INC. AND ADVANCED RESOURCES INTERNATIONAL, ASSESSMENT OF UNDISCOVERED OIL AND GAS RESOURCES IN THE GREATER GREEN RIVER AND WIND RIVER BASINS

INTRODUCTION

The subject assessment (Boswell et al, 2002b) of resources was prepared under a Department of Energy contract. It was prepared in response to recommendations made by the National Petroleum Council in their 1999 report, "Meeting the Challenges of the Nation's Growing Natural Gas Demand". The Greater Green River and Wind River basins were studied because past gas-in-place resource assessments indicated that these two areas contain the vast majority of the total tight-gas sandstone resource for the Rocky Mountain region. To obtain a portion of these resources, the oil and gas industry will need to apply "advanced exploration, drilling, completion, stimulation, and production technologies in order to produce gas economically and at reasonable prices" (Boswell et al., 2003b). Their report attempts to provide a better understanding of the size and nature of the gas resources that will be critical to future gas supply and the potential of technology to convert presently unrecoverable and sub-economic resources into economically recoverable resources.

The study of the Greater Green River Basin focused on deeper, unconventional gas resources. It reviewed the Cretaceous and older geologic section to identify plays that:

- encompass most of the basin's gas resources,
- were dominated by deep and/or unconventional type accumulations, and
- had sufficient data available to use the proposed project methodology.

Their study identified for further review the section from the top of the Lance Formation to the base of sandstones within the Morrison Formation, and excluded the Fox Hills Sandstone and various stray sandstones within the Cody-Baxter-Hilliard-Steele shale interval (see Figure 6 for stratigraphic nomenclature). This interval was further divided into "units of analysis." Each unit of analysis can be thought of as intervals with a common geologic condition that would likely be a target for an individual well. In the past, the Mesaverde Group has commonly been assessed as one unit. Intervals of the Mesaverde were split out for this study because it has such a large stratigraphic thickness, industry would not likely target the entire interval in an individual well. The authors were able to divide the studied interval into seven units of analysis. All seven of those units of analysis lie at least partially within the Field Office area. A description of each unit is presented below, in order from youngest to oldest.

- The Lance unit of analysis (Figure A1-1) is comprised of multiple beds of fluvial sandstones, and interbedded siltstone, shales, and coal of the Lance Formation.

- The Lewis unit of analysis (Figure A1-2) includes clean shallow-water delta-front sandstones and thick, vertically-stacked sequences of thin-bedded and shale-rich sandstones representing deeper water turbidites.
- The Almond unit of analysis (Figure A1-3) includes Almond Formation sandstones of two distinct types. The first type is clean, blocky and coarsening-upwards sandstone that mark the migration of shorelines at the top of the Almond. The second type, are thinly bedded and highly lenticular sandstones of the lower part of the delta plain that are interbedded with coals and shales. The Almond unit of analysis lies at the top of the Mesaverde Group.
- The Ericson unit of analysis (Figure A1-4) includes massive, quartz-rich sandstones of the Ericson Formation that lie in the middle of the Mesaverde Group.
- The Lower Mesaverde unit of analysis (Figure A1-5) contains two distinct intervals. At its base are thick, coarsening upward sequences of sandstone (the Blair Formation). Above that lie a thick section of highly lenticular fluvial sandstones and shales (the Rocks Springs Formation).
- The Frontier unit of analysis (Figure A1-6) includes five benches of the Lower Frontier Formation and sandstones within the Mowry Shale interval.
- The Muddy-Dakota-Morrison unit of analysis (Figure A1-6) includes the Muddy Sandstone, the Dakota Sandstone, and sandstones within the Morrison Formation. Those sandstones are interpreted to represent deposition during fluvial-dominated sedimentation.

The assessment attempted to produce a dataset from which recoverable resources could be appraised now, and as changes occur over time, with change in future conditions. A summary of the methodology used is described below.

- Obtain evenly distributed well log data.
- Subdivide stratigraphic section into units of analysis that will be modeled as separate drilling targets.
- Establish three-dimensional geometry of each unit of analysis.
- Establish the distribution of resource-bearing sandstone facies to improve extrapolation of parameters to areas of poor data control.
- Estimate unit of analysis values of porosity, drilling depth, resistivity, shale volume, and potential pay thickness for each well log suite.
- Estimate pressure and temperature gradients and water resistivity at township or quarter-township scale.
- Estimate expected matrix permeability and likely natural fracture overprint.
- Distribute scattered well data to regular grid filling unit of analysis area.
- Prepare data for model input and remove areas of significant historical production.
- Conduct analysis to determine gas-in-place, and the impact of technology/cost scenarios on economically- and technically-recoverable volumes.

The central and easternmost parts of the Field Office area were not reviewed as part of the subject assessment. As a result, resource predictions made below, only were made for that portion of the Field Office area within the Greater Green River Basin.

RESULTS

Table A1-1 presents the estimated gas-in-place for the seven units of analysis that lie partially within the Field Office area. The Greater Green River Basin calculated volume of gas-in-place present within the seven units of analysis totals 3,638 trillion cubic feet of gas. Of that total, 595.7 trillion cubic feet of gas is predicted to lie below 15,000 feet. To determine that portion of the gas that lies within the Field Office area; we assumed that the gas resource was evenly distributed across each unit of analysis, we determined the percent of each unit of analysis area that lies within the Field Office area, and we then multiplied that percentage by the basin-wide gas-in-place value for each unit of analysis. We determined that about 1,051.6 trillion cubic feet of gas-in-place, might be contained within the Field Office area. Of that total, we predict that 141.8 trillion cubic feet of gas lies below 15,000 feet. The Lower Mesaverde alone contains about one third of the total gas-in-place within the Field Office area. The Almond contains the smallest amount of gas-in-place (about three percent). The Muddy-Dakota-Morrison interval contains the most gas-in-place (31 percent) below 15,000 feet, while the Lance contains almost no gas (0.18 percent).

Some of the more important average reservoir parameters, calculated for the subject analysis, are also presented in Table A1-1. A log-analysis procedure was used to determine average "potential reservoir thickness". The reservoir within each assessment unit was equated with each interval that could be expected to produce under current circumstances. The Lance and Lower Mesaverde units of analysis contain the thickest amount of potential reservoir, while the Almond has the least.

The average porosity and water saturation were then calculated from well logs and those calculations were used to determine the reservoir thickness of each unit of analysis. Units with higher porosity and lower water saturation have more space to accommodate gas resources. Average porosity of all potential reservoirs is very uniform. Water saturation averages for the shallower units of analysis (Lance, Lewis, Almond, Ericson, and Lower Mesaverde) are in the 53 to 62 percent range, while the two deeper units of analysis (Frontier and Muddy-Dakota-Morrison) have much lower water saturations. Even though the Ericson has more than twice the reservoir thickness of the Frontier and Muddy-Dakota-Morrison, it only has about the same range of gas-in-place. The higher water saturation of the Ericson is the main reason its gas-in-place value is so similar to these two thinner reservoirs.

Average drilling depth was calculated as the mid-point of the reservoir for each unit of analysis. The pressure data was obtained from individual pressure build-up tests on key wells and supplemented by drilling mud-weight data. Reservoir temperature data was based on existing databases and supplemented by temperatures recorded on well logs.

Boswell et al. (2003b) also analyzed resource recoverability for each unit of analysis within the Greater Green River Basin (Table A1-2). Their technically recoverable resource is defined as that part of the in-place gas resource that can be extracted given current technologies and drilling practices, without regard to price. They estimated that 363 trillion cubic feet of gas was recoverable from the seven units of analysis. To determine that part of the technically recoverable gas that lies within the Field Office area; we assumed that the gas resource was evenly distributed across each unit of analysis, we determined the percent of each unit of analysis area that lies within the Field Office area, and we then multiplied that percentage by the basin-wide technically recoverable gas value for each unit of analysis. We determined that about **108.88 trillion cubic feet of technically recoverable gas**, might be contained within the Greater Green River Basin portion of the Field Office area.

The Boswell et al. (2003b) assessment of technically recoverable gas is significantly higher than that of the U.S. Geological Survey (see Appendix 2). Differences stem from the use of alternative methodologies, different geologic models, and different assumptions. For example, the U.S. Geological Survey estimates for continuous-type assessment units are based on extrapolating past production history to the assessment unit's remaining untested regions and therefore, is influenced by past economic decisions of operators. The Boswell et al. (2003b) assessment of technically recoverable resources is based on the reservoir geology modeled with current technology and assuming full resource development. In addition, the U.S. Geological Survey limits their analysis to a 30-year forecast span that reduces their estimate further when compared to that of Boswell et al. (2003b).

APPENDIX 2 - U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED OIL AND GAS RESOURCES

INTRODUCTION

The U.S. Geological Survey has published three assessments of undiscovered oil and gas resources that cover parts of the Rawlins Field Office area. Their “1995 National Assessment of United States Oil and Gas Resources” (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) scientifically estimated the amount of crude oil, natural gas, and natural gas liquids that could be added to proved reserves in the United States, assuming existing technology. It presented information about potential undiscovered accumulations of oil and gas in 71 geologic or structural provinces within the United States. Two of those provinces, the Southwestern Wyoming and Denver Basin provinces, lie partly within the Field Office area.

Recently the U.S. Geological Survey revised their methods of preparing assessments. They used that new method to update their quantitative estimate of the undiscovered oil and gas resource for part of the Southwestern Wyoming Province and the Denver Basin Province (U.S.G.S.; 2002, 2003a, 2003b, and 2003c). That part of the Southwestern Wyoming Province studied for the new analysis includes only the Greater Green River Basin (Great Divide and Washakie basins and Wamsutter Arch parts of the Field Office). In the following analysis, we will use the newer 2002 Southwestern Wyoming Province assessment and the 2003 Denver Basin Province assessment to describe the potential undiscovered technically recoverable oil and gas resources lying within the Field Office area. For that part of the Southwestern Wyoming Province not reassessed, we will use data from the earlier assessment.

SOUTHWESTERN WYOMING PROVINCE ASSESSMENT

The Southwestern Wyoming Province occupies most (the western and central parts) of the Field Office area. Its full extent includes the Green River, Hoback, Great Divide, Washakie, Hanna, Carbon, Sand Wash, and Laramie basins. It also includes uplifts such as the Moxa, Sandy Bend, and Wamsutter arches as well as the Rock Springs uplift and Cherokee Ridge. The province covers about 40,500 square miles in parts of Wyoming, Colorado, and Utah. In the Field Office portion of the province, the total sedimentary rock thickness is up to about 38,000 feet (Wilson, et al., 2001) in the Hanna Basin area. Oil and gas production in the Field Office portion of the province has been most concentrated in the Great Divide and Washakie basins and along the Wamsutter Arch.

<u>Assessment Unit Summaries</u>

In their newest assessment, the U.S. Geological Survey (2002 and 2003b) divided the Southwestern Wyoming Province into “total petroleum systems” and “assessment units” (see Glossary definitions) rather than “plays.” “The total petroleum system approach is designed to focus the geologic studies on the hydrocarbon source rocks, processes that create hydrocarbons, migration pathways, reservoirs, and trapping mechanisms” (Cantey et al., 2003). Each assessment unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definitions). Most of the older fields within the Field Office area can be classified as conventional accumulations of hydrocarbons. Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. Most of the more recent discoveries of hydrocarbons in the Field Office area have been considered to be part of continuous accumulations.

The U.S. Geological Survey recognized seven conventional assessment units in the Southwestern Wyoming Province. Six of the seven identified assessment units lie partly within the Field Office boundary (Figures A2-1, A2-2, A2-3, A2-4, A2-5, and A2-6). The U.S. Geological Survey has made available some statistical information for these assessment units (Table A2-1), but the supporting geologic studies await formal publication.

The U.S. Geological Survey also recognized 16 continuous assessment units in the Southwestern Wyoming Province. Twelve of the 16 identified continuous assessment units, including two coalbed gas units, lie partly within the Field Office boundary (Figures A2-7, A2-8, A2-9, A2-10, A2-11, A2-12, A2-13, A2-14, A2-15, A2-16, A2-17, and A2-18). Again, the U.S. Geological Survey has made available some statistical information for these assessment units (Table A2-2), but the supporting geologic studies await formal publication. The Niobrara continuous oil assessment unit was not quantitatively assessed.

Play Summaries

Figure A2-19 shows the location of that part of the newest Southwestern Wyoming Province assessment. That part of the Southwestern Wyoming Province that was not updated in the newest assessment lies immediately to the east and extends to the boundary of the Denver Basin Province. Parts of two older “play” areas (subthrust and platform plays) cover the easternmost part of the province (Figures A2-20 and A2-21). The older assessment divided the province into “play” areas. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play “by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects.” The two plays are defined as conventional type plays. A conventional play will contain oil and gas accumulations having hydrocarbon-water contacts (due to the buoyancy of hydrocarbons in water) and seals that hold or trap the hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices.

The U.S. Geological Survey defined subthrust play (Figure A2-20) is speculative and includes areas along overridden thrust margins of basins in the province (Gries, 1983). Reservoirs could be within any sandstone or carbonate of Cambrian through Tertiary age (Figure 6). Traps that may be present include:

- conventional anticline
- stratigraphic
- fault truncation of upturned strata
- fracturing.

The Southwestern Wyoming Province appears to contain more drilled wells in subthrust plays than anywhere else in the Rocky Mountain region, yet the U.S. Geological Survey considers the play to be immature to moderately explored. Large areas have still not been drilled and no fields have been discovered in the play area. The U.S. Geological Survey has estimated that 1 to 5 oil accumulations and 1 to 5 gas accumulations (with greater than one million barrels of oil equivalent) could yet be discovered. Mean accumulation size would be 9.4 million barrels of oil or 35.5 billion cubic feet of gas, depending on accumulation type (oil or gas). They predicted that any oil accumulations would lie within the 5,000 to 17,000 foot range and gas accumulations would lie within the 5,000 to 30,000 foot range.

The platform play (Figure A2-21) is primarily a structural play, with all existing fields lying in structural traps. Some of Wyoming's oldest fields are located within this play area. Reservoirs could be within any sandstone or carbonate of Cambrian through Tertiary age (Figure 6). In addition to structural traps, the potential for stratigraphic traps does exist. The platform play has been maturely explored, and there have been only a few discoveries within this play since 1960. The U.S. Geological Survey has estimated that 1 to 6 oil accumulations and 1 to 4 gas accumulations (with greater than one million barrels of oil equivalent) could yet be discovered. Mean accumulation size would be 13.0 million barrels of oil or 9.0 billion cubic feet of gas, depending on accumulation type (oil or gas). They predicted that any oil accumulations would lie within the 1,000 to 12,000 foot range and gas accumulations would lie within the 1,000 to 13,000 foot range.

Assessment Unit and Play Resource Results

The U.S. Geological Survey (2002 and 2003b) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. The U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996) did not use a forecast span to estimate undiscovered technically recoverable resource quantities for the two play areas from their "1995 National Assessment of United States Oil and Gas Resources." Below, we summarize the estimated volumes of hydrocarbons in the six conventional and 12 continuous assessment units and the two conventional play areas, lying at least partly within the Field Office area. The U.S. Geological Survey did not quantitatively assess the Niobrara Gas continuous assessment unit, because it lacks sufficient supporting data to calculate resource estimates. In the future, if reserves are discovered within this assessment unit, resulting resource estimates would be greater than those presented below.

In Table A2-3, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units and for the two play areas in the Southwestern Wyoming Province, together with our projection of the amount of those hydrocarbons that could be present within the Field Office area. To determine the potential resource within the Field Office area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit or play area,
- calculated the percent of each assessment unit or play that lies within the Field Office area, and
- multiplied that percentage by the U.S. Geological Survey estimates for the entire assessment unit or play area to calculate Field Office area resource values.

Our estimates of recoverable resources for each assessment unit or play area within the province and within the Field Office area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a five percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Field Office area contains a mean undiscovered volume of **43.68 million barrels of oil, 30.495 trillion cubic feet of gas, and 746.04 million barrels of natural gas liquids,** in the Southwestern Wyoming Province assessment units and play areas.

DENVER BASIN PROVINCE ASSESSMENT

The Denver Basin Province report was prepared as part of the U.S. Geological Survey's ongoing "National Oil and Gas Resource Assessment." The Denver Basin Province occupies the easternmost part of the Field Office area (Figure A2-19). It is a Laramide-aged structural basin located in eastern Colorado, southeastern Wyoming, the southwestern corner of South Dakota, and the Nebraska Panhandle. Productive traps have been primarily stratigraphic (mainly facies change and updip pinch-out of reservoir intervals). The Denver Basin Province occupies a small part of the Field Office area in a region where only a small portion of the mineral estate is managed by the Bureau.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2003a and 2003c) divided the Denver Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays." Each assessment unit falls within one of two types of potential undiscovered accumulation: conventional and continuous accumulations (see Glossary definitions). Most of the older fields within the Field Office area can be classified as conventional accumulations of hydrocarbons. Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. The Silo Field area (Figure 10) is presently the only continuous accumulation producing within the Field Office Area.

The U.S. Geological Survey recognized five conventional assessment units in the Denver Basin Province. Four of the five identified assessment units lie partly within the Field Office boundary (Figures A2-22, A2-23, A2-24, and A2-25). The U.S. Geological Survey has made available some statistical information for these assessment units (Table A2-4), but the supporting geologic studies await formal publication.

The U.S. Geological Survey also recognized seven continuous assessment units in the Denver Basin Province. Three of the seven identified continuous assessment units, including two coalbed gas units, lie partly within the Field Office boundary (Figures A2-26 and A2-27). Again, the U.S. Geological Survey has made available some statistical information for these assessment units (Table A2-5), but the supporting geologic studies await formal publication. The Denver Formation Coals and Laramie Formation Coals coalbed gas assessment units were not quantitatively assessed.

<u>Assessment Unit Resource Results</u>

The U.S. Geological Survey (2003a and 2003c) estimated undiscovered technically recoverable resource quantities of oil and gas that could be added to the proved reserves within each assessment unit, using a forecast span of 30 years. A 30-year forecast span affects the minimum undiscovered accumulation size, the number of years in the future that reserve growth is estimated, economic assessments, the accumulations chosen for consideration, and the assessment of risk. Below, we summarize the estimated volumes of hydrocarbons in the four conventional and three continuous assessment units lying at least partly within the Field Office area. The U.S. Geological Survey did not quantitatively assess the Denver Formation Coals and Laramie Formation Coals coalbed gas assessment units, because they lack sufficient supporting data to calculate resource estimates. In the future, if reserves are discovered within these two assessment units, resulting resource estimates would be greater than those presented below.

In Table A2-6, the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) are shown for the conventional and continuous assessment units in the Denver Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Field Office area. To determine the potential resource within the Field Office area we:

- assumed a homogenous distribution of each hydrocarbon type within each assessment unit,
- calculated the percent of each assessment unit that lies within the Field Office area, and
- multiplied that percentage by the U.S. Geological Survey estimates for the entire assessment unit to calculate Field Office area resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Field Office area, are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a five percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Field Office area contains a mean undiscovered volume of **11.92 million barrels of oil, 15.73 billion cubic feet of gas, and 1.97 million barrels of natural gas liquids,** in the Denver Basin Province assessment units.

Proved reserves (cumulative production plus remaining reserves) were also estimated by the U.S. Geological Survey (TableA2-7). They only estimated proved reserves for the Dakota Group and D Sandstone and for the Permian-Pennsylvanian Reservoirs assessment units. We determined the proved reserves lying within the Field Office area in the same manner as we determined undiscovered resources above. Estimated proved reserves for the two assessment units are **44.72 million barrels of oil, 60.36 billion cubic feet of gas, and 4.16 million barrels of natural gas liquids**, in the Denver Basin Province.