INTRODUCTION 7

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS 9

EXPLORATORY ACTIVITY AND OPERATIONS 9
FEDERAL DEVELOPMENT CONTRACTS 13
FEDERAL OIL AND GAS UNIT AGREEMENTS 13
COMMUNITIZATION AGREEMENTS 14
TYPICAL DRILLING AND COMPLETION SEQUENCE 14
DRAINAGE PROTECTION 16
HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED 16
EARLY EXPLORATION AND DEVELOPMENT ACTIVITY 16
PRODUCING ZONES 19
TECHNOLOGY DEVELOPMENT 19
DRILLING AND COMPLETION ACTIVITY 20
DRILLING RIG COUNTS 21
PRODUCTION 21
COALBED NATURAL GAS 24
MARGINAL WELLS 24
DEEP WELL DRILLING: GREATER THAN 15,000 FEET 25
DEEP WELL DRILLING AND COMPLETION ACTIVITY: 10,000 TO 15,000 FEET 26
WELL DRILLING AND COMPLETION ACTIVITY: 0 TO 10,000 FEET 26
SUMMARY OF CURRENT DRILLING TECHNIQUES AND TRENDS 27
Directional and Horizontal Drilling and Completion Activity 27
Reverse Circulation Drilling 30
Slimhole Drilling and Coiled Tubing 30
Light Modular Drilling Rigs and Pad Drilling 31
Pneumatic Drilling 31
Measurement-While-Drilling 31
Improved Drill Bits 31
SUMMARY OF CURRENT COMPLETION TECHNIQUES 32
DRILLING AND COMPLETION COSTS 32
SUMMARY OF PRODUCTION AND ABANDONMENT TECHNIQUES 33
SECONDARY OIL RECOVERY 35
ENHANCED OIL RECOVERY 35
SECONDARY AND ENHANCED RECOVERY PROJECTS IN SOUTH DAKOTA 36
Waterflooding and Gas Injection 36
Steamflooding 37
Polymer-Enhanced Waterflooding 37
Surfactant Flooding 37
In-Situ Combustion (High Pressure Air Injection) 37
Carbon Dioxide Injection 38

Acid Gas Removal and Recovery 39
Artificial Lift Optimization 39
Glycol Dehydration 39
Produced Water Management 39
Leak Detection and Low-bleed Equipment 40
Downhole Water Separation 40
Vapor Recovery Units 41
Site Restoration 41
UNDERGROUND GAS STORAGE 41

ASSESSMENTS OF OIL AND GAS RESOURCES 41

OIL-IN-PLACE ESTIMATES 43
GAS-IN-PLACE ESTIMATES 43
PROVED OIL AND GAS RESERVES 44
U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS 44
DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS 45
POTENTIAL GAS COMMITTEE ASSESSMENT 46
NATIONAL PETROLEUM COUNCIL ASSESSMENT 47
RAND SCIENCE AND TECHNOLOGY ASSESSMENT 47
BIOGENIC AND SHALLOW GAS 48
RESERVATION LANDS 49

OIL AND GAS OCCURRENCE POTENTIAL 50

PROJECTIONS OF FUTURE ACTIVITY 2010-2029 51

OIL AND GAS PRICE ESTIMATES 52
Gas Prices 52
Oil Prices 54
LEASING 55
SEISMIC SURVEYS 56
PROJECTIONS OF FUTURE DRILLING ACTIVITY 56
Projected Oil and Gas Drilling Activity 57
Projected Coalbed Natural Gas Drilling 59
PRODUCTION 60
ESTIMATED FUTURE OIL AND GAS PRODUCTION 61
OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES 62
Shale Gas 62
Coal Gasification 63
Carbon Dioxide Sequestration 63

PIPELINE INFRASTRUCTURE **65**

POTENTIAL SURFACE DISTURBANCE **65**

SUMMARY **66**

REFERENCES **67**

APPENDIX 1 - U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED OIL AND GAS RESOURCES WITHIN THE STUDY AREA **78**

INTRODUCTION **78**
DENVER BASIN PROVINCE ASSESSMENT **78**
ASSESSMENT UNIT SUMMARIES 78
ASSESSMENT UNIT RESOURCE RESULTS 79
WILLISTON BASIN PROVINCE ASSESSMENT **80**
ASSESSMENT UNIT SUMMARIES 80
ASSESSMENT UNIT RESOURCE RESULTS 81
SIOUX ARCH PROVINCE ASSESSMENT **82**
PLAY SUMMARIES 82

GLOSSARY **84**

Figure List

Figure 1. The South Dakota Study Area and its location within the South Dakota Planning Area.
Figure 2. Location and initial status of all wells drilled within the South Dakota Study Area.
Figure 3. Major structural elements of the South Dakota Study Area.
Figure 4. Stratigraphic chart of South Dakota Study Area, with oil and gas bearing zones indicated.
Figure 5. Field boundaries within Harding County, in the northern part of the South Dakota Study Area.
Figure 6. Field boundary within Dewey County, in the northern part of the South Dakota Study Area.
Figure 7. Field boundaries within Fall River and Custer Counties, in the southwestern part of the South Dakota Study Area.

Figure 8. Location of all Harding County oil and gas unit agreements within South Dakota Study Area.
Figure 9. Location of all Fall River County oil and gas unit agreements within South Dakota Study Area.
Figure 10. Location of all communitization agreements within South Dakota Study Area.
Figure 11. Views of the Indian School water well showing bubbles from associated gas (top) and New Gas No. 1 well (bottom), Pierre, South Dakota, circa 1929(Bureau of Land Management, Wyoming State Office archives).
Figure 12. Oil and gas yearly production rates for South Dakota Study Area.
Figure 13. Oil and gas cumulative production rates for South Dakota Study Area.
Figure 14. Historical five year epoch oil production data for South Dakota Study Area.
Figure 15. Historical five year epoch gas production data for South Dakota Study Area.
Figure 16. Known areas of coal bearing sediments within South Dakota Study Area, Fort Union and Black Hills coal regions.
Figure 17. Range of drilling depths for all vertical and deviated (directional and horizontal) wells, within South Dakota Study Area (IHS Energy Group, 2008).
Figure 18. All vertical and all deviated wells with a recorded true vertical depth greater or less than 5,000 feet deep within the South Dakota Study Area.
Figure 19. Range of drilling depths for all vertical and deviated (directional and horizontal) producing wells within South Dakota Study Area (IHS Energy Group, 2008).
Figure 20. All producing vertical wells and all producing deviated wells with a recorded true vertical depth greater or less than 5,000 feet deep within the South Dakota Study Area.
Figure 21. Wells spudded between January 1, 1998 and December 31, 2007 within the South Dakota Study Area.
Figure 22. Chart of frequency of horizontal wells spudded in the South Dakota Study Area from 1994 through 2007.
Figure 23. Geographic distribution of water quality samples across the Study Area and distribution of sample salinity.
Figure 24. Potential for occurrence of oil and gas within South Dakota Study Area, 2010 through 2029.
Figure 25. South Dakota historical natural gas prices with future natural gas price projections (Energy Information Agency, 2008)
Figure 26. South Dakota historical crude oil prices with future crude oil price projections (Energy Information Agency, 2008).
Figure 27. Leased and unleased Federal oil and gas minerals within South Dakota Study Area.
Figure 28. Present two-dimensional seismic survey density with South Dakota Study Area.
Figure 29. Oil and gas (excluding coalbed natural gas) development potential within South Dakota Study Area, 2010 though 2029.
Figure 30. Coalbed natural gas development potential within South Dakota Study Area, 2010 through 2029.

Table List

Table 1. Cumulative oil and gas production by field for the South Dakota Study Area.
Table 2. Cumulative oil and gas production by operator for the South Dakota Study Area.
Table 3. Active secondary and enhanced recovery units in the Study Area.
Table 4. Estimated oil and gas (excluding coalbed natural gas) development potential classification acres, number of townships, projected average drilling densities, and percentage of the South Dakota Study Area within each development potential classification type for the period 2010 through 2029.
Table 5. Annual projection of South Dakota Study Area wells drilled from 2010 through 2029 and their associated confidence interval.
Table 6. Forecast of South Dakota Study Area annual and cumulative oil and gas production for 2010 through 2029.
Table 7a. Disturbance Associated With New Drilled Wells, Existing Wells, and Projected Active Wells for the Baseline Scenario (Short-Term Disturbance).
Table 7b. Disturbance Associated With New Producing Wells, Existing Wells, and Projected Producing Wells for the Baseline Scenario (Long-Term Disturbance).

Appendix 1 – Figure List

Figure A1-1. Location of the provinces lying partially within the Study Area (U.S. Geological Survey, 2008).
Figure A1-2. Location of the Denver Basin Province, Lower Cretaceous total petroleum system (Dakota Group and D Sandstone assessment unit) and Permian-Pennsylvanian total petroleum system (Permian-Pennsylvanian reservoirs assessment unit) with respect to the Study Area boundary.
Figure A1-3. Location of Denver Basin Province, Upper Cretaceous Niobrara Biogenic Gas total petroleum system, Niobrara Chalk assessment unit with respect to the Study Area boundary.
Figure A1-4. Location of Williston Basin Province, Coalbed Gas total petroleum system, Fort Union Coalbed Gas assessment unit with respect to Study Area boundary.
Figure A1-5. Location of Williston Basin Province, Red River total petroleum system, Red River Fairway and Interlake-Stonewall-Stony Mountain assessment units with respect to Study Area boundary.
Figure A1-6. Location of Williston Basin Province, Red River total petroleum system, Red River East Margin assessment unit with respect to Study Area boundary.
Figure A1-7. Location of Williston Basin Province, Duperow-Birdbear, and Dawson Bay-Souris River assessment units with respect to Study Area boundary.
Figure A1-8. Location of Williston Basin Province, Cedar Creek Paleozoic total petroleum system, Cedar Creek Structural assessment unit with respect to Study Area boundary.
Figure A1-9. Location of Williston Basin Province, Tyler total petroleum system Tyler Sandstone assessment unit with respect to Study Area boundary.
Figure A1-10. Location of Williston Basin Province, Shallow Biogenic Gas total petroleum system, Shallow Biogenic Gas assessment unit with respect to Study Area boundary.

Figure A1-11. Location of Sioux Arch Province, Truncated Paleozoics Play (hypothetical) with respect to Study Area boundary.

Appendix 1 – Table List

Table A1-1. Data for undiscovered conventional accumulations in assessment units in the Denver Basin Province, South Dakota Study Area.
Table A1-2. U.S. Geological Survey estimated undiscovered technically recoverable resource quantities within Denver Basin Province and the Study Area.
Table A1-3. U.S. Geological Survey estimated undiscovered technically recoverable resource quantities within Williston Basin Province and the South Dakota Study Area.

INTRODUCTION

The South Dakota Planning Area (Study Area) occupies the entire state, although for this report we were only asked by the Bureau of Land Management (Bureau), North Dakota Field Office, to prepare reasonable foreseeable development scenarios for approximately the western half of the state (Figure 1). The main goal of this reasonable foreseeable development projection is to technically analyze the oil and gas resources known to occur and potentially occurring within the Study Area and to project future development potential and activity levels for the period 2010 through 2029. Historic oil and gas related development areas are presented for all lands, including Indian Reservation lands (Figure 2).

Our analysis makes a base-line projection that assumes future oil and gas related activity levels on all assessed lands within the Study Area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2002). National Forest lands, other Federal agency lands, Indian Reservation lands, and State managed lands are included in the base-line projection for those lands assessed for future development (Figure 1). Certain other federally managed lands within the Study Area are not assessed for the potential for future reasonable foreseeable oil and gas related development. Those lands with legislatively imposed restrictions (no leasing) are not included in this base-line projection since oil and gas activities will not be allowed. Those restricted lands are National Park Service lands (Figure 1).

The reasonable foreseeable development evaluation and projections presented below review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential for oil and gas, coalbed natural gas, and deep oil and gas (at depths greater than 15,000 feet), as well as available estimates of the hydrocarbon resources that may be present within the Study Area. Additional 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, a review of petroleum technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are not worst-case projections, but reasonable and science based projections of the anticipated oil and gas activity, and logical and technically based assumptions were used to make those projections. Finally, projections of future activity levels for each resource management plan alternative are presented.

The Study Area contains about 25,838,451 surface acres of all oil and gas mineral ownership types. Total Federal oil and gas mineral ownership, in the Study Area, amounts to about 3,374,457 acres, or about 13 percent of total acres. Indian tribes and individual Allottees own about 7,028,785 surface acres, or about 27 percent of total acres. The oil and gas resource on these lands are managed for the tribes by the Bureau of Indian Affairs and the Bureau. The remaining 15,435,209 acres (60 percent) is owned by state and private interests.

The U.S. Forest Service manages most of the Federal oil and gas mineral lands in the Study Area (about 1.774 million acres, or about 53 percent). The Bureau manages about 1.471million acres of the Federal oil and gas mineral lands in the Study Area (about 44 percent). All Bureau managed oil and gas mineral lands will be covered by decisions made in the associated Resource Management Plan/EIS.

Smaller amounts of Federal oil lands within the Study Area are managed by the National Park Service (about 103,845 acres or about three percent), Bureau of Reclamation (about 14,219 acres) and Military Reservations/Corps of Engineers (about 14,219 acres). Decisions made as part of the Resource Management Plan/EIS for the Study Area will be made for these lands, excluding the National Park lands. Any decisions made for Bureau of Reclamation and Military Reservations/Corps of Engineers lands will be made in consultation with the surface management agency in the Resource Management Plan/Environmental Impact Statement.

We would like to thank Cathy Stilwell of the Bureau of Land Management, Wyoming State Office, Reservoir Management Group staff and Allen Ollila of the Bureau of Land Management, North Dakota Field Office for the important contributions that they have made to this reasonable foreseeable development analysis. In addition, we would like to thank Russell Pigors, John Bown, and Jack Wunder for their review of the first draft of this document.

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 Study 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 ACTIVITY AND OPERATIONS

The petroleum industry in the U.S. has historically relied on continual improvements in technology to better understand the oil and gas resource locked in the earth and to find and produce it. Some of the biggest breakthroughs have been:

- the anticlinal theory (1885) that oil and gas tend to accumulate in anticlinal structures, which allowed drillers to locate better drilling spots with improved opportunities to find oil and gas;
- rotary drilling rigs (1900s), which became the chief method of drilling deeper wells;
- seismograph (1914), which allowed one dimensional subsurface imaging;
- well logging (1924), which allowed measurement of subsurface rock and fluid properties;
- digital computing (1960s), which allowed two dimensional imaging of data;
- directional drilling (1970s), which allowed more cost efficient management of reservoirs;
- three dimensional seismic (1980s), which allowed more accurate subsurface imaging;
- three dimensional modeling and four dimensional seismic (1990s), which allowed the prediction of fluid movement in the subsurface;
- identification of new types of reservoirs and improved exploitation methods (1990s to present) allowed development of heavy oil, tight gas, shale gas, coalbed natural gas, and the use of carbon dioxide in the flooding process to increase recoveries; and
- multi-discipline collaboration (2000s), which allows for better drilling decisions, higher success rates, improved risk assessment, and enhanced reservoir development.

Exploratory activity includes:

- the study and mapping of surface and subsurface geologic features to recognize potential oil and gas traps,
- determining a geologic formations potential for containing economically producible oil and gas,
- 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, and
- completing wells that appear capable of producing economic quantities of oil and gas.

A number of components can control and characterize potential oil and gas accumulations in the Study Area. Those major components of accumulations can be:

1. Major structural elements of the Study Area (Figure 3) define regions with different oil and gas target types. The largest part of the Study Area lies within the Williston Basin, defined by Peterson (1995) as a structural-sedimentary intracratonic basin (see Glossary) located on the western shelf of the Paleozoic North American craton (see Glossary). It contains the productive Ordovician Red River Formation and Cretaceous Shannon Sandstone (Figure 4) fields in Harding County (Figure 5) and one Ordovician Red River Formation oil field in Dewey County (Figure 6) of the Study Area. The eastern Powder River Basin area is also an intracratonic basin and in the Study Area it contains oil fields (Figure 7) producing from the Minnelusa Formation (Leo Sandstone). One Minnelusa Formation (Leo Sandstone) oil field (Barker Dome Field, see Figure 7) produces on the southern end of the Black Hills Uplift. The other three structural elements (Sioux Ridge, Kennedy Basin, and Chadron Arch) do not presently produce hydrocarbons.
2. Accumulations of sandstones, carbonates, shales, and locally coal (potential source and reservoir rocks) exist.
3. Burial and thermal histories that promoted the development and preservation of diagenetic pore-throat traps (see Glossary) and extensive oil and gas generation.
4. Structure traps (see Glossary) have played a large role in localizing oil and gas accumulations, especially when coupled with stratigraphy.
5. Stratigraphic traps (see Glossary), such as the Red River Formation horizontal drilling play, have had a large role in exploration and development in the northwest part of the Study Area in recent years (since 1994).
6. Secondary porosity, produced by the dissolution of unstable grains and rock fragments, dolomitization, or fracturing, is important in local accumulations.

We believe that these components are important in exploring for and developing new oil and gas resources in the Study Area. Almost all recent drilling activity (since 1994) has occurred in the northwest part of the Study Area (Figure 2). Minor amounts of exploratory and development activity have occurred in the southwest (Fall River County), with occasional exploratory wells being drilled at widely scattered locations within the Study Area.

Of the 187 boreholes (see Glossary) spudded (see Glossary) in the 10-year period (January, 1998 through December, 2007), 53 wells (28 percent) were initially classified as wildcats, 131 as development wells, and two as injection wells (see Glossary) as defined by IHS Energy Group, (2008). These new wildcat wells are concentrated within Harding and Butte counties in the northwest part of the Study Area (30 boreholes), in Fall River County in the southwest portion (16 boreholes), and in Stanley County (seven wells). During this period nine were completed as oil producible, three were completed as gas producible, 29 were drilled and abandoned, and 15 were not yet completed (10 spuds, four temporarily abandoned, and one suspended). Of the completed boreholes, 29 percent were successful. Only seven wildcat boreholes were drilled horizontally (12.5 percent) with six successfully completed as oil wells and one still temporarily abandoned. Of the seven wildcat wells spudded in Stanley County five were drilled and abandoned and a final completion status was not yet available for the other two.

Nineteen operators were responsible for the 53 wildcats drilled. The top six operators (Peter K. Roosevelt, Fidelity Exploration and Production, Luff Exploration Company, The Houston Exploration Company, Spyglass Cedar Creek, and Delta Petroleum) are responsible for 37 wells (66 percent). Six operators are responsible for only two wildcats and the other seven operators drilled one well each.

Vertical drilling depths for all wildcats have ranged from 517 to 9,140 feet. More than 79 percent were drilled to depths of 4,000 feet or less. The remaining boreholes (21 percent) were deeper than 5,900 feet in depth.

Of the 131 development boreholes spudded in the 10-year period (January, 1998 through December, 2007), 130 are concentrated within Harding County in the northwest part of the Study Area, and one lies in Custer County in the southwest portion (IHS Energy Group, 2008). During this period 118 were completed as oil producible, eight were completed as gas producible, three were drilled and abandoned, and one was not yet completed. Almost all development boreholes were drilled horizontally (90 percent) with six drilled directionally and only seven drilled vertically. Of the completed boreholes, about 98 percent were successful oil or gas wells. This rate is quite high due to the additional horizontal bore holes drilled from existing wells.

Only eight operators were responsible for the 131 development boreholes drilled. Their share of the development drilling was:

- Continental Resources Inc. – 56 wells;
- Luff Exploration Company – 53 wells;
- Prima Exploration – 10 wells;
- Sands Oil Company – 5 wells;
- David L. Arnold – 2 wells;
- Bowers Oil & Gas Inc. – 2 wells;
- Murex Petroleum Corp, – 2 wells;
- L&J Operating Inc. – 1 well.

Only a handful of development boreholes drilled were vertical (7 wells). These wells were shallow (1,200 to 1,600 feet in depth). Four were drilled at Cady Creek Field, two at West Short Pine Field, and one at Barker Dome Field. True vertical drilling depths for horizontal development boreholes range from 8,400 to 9,400 feet in the Study Area.

Innovative drilling and completion techniques have enabled the industry to drill fewer dry holes and to recover more oil and gas reserves per well. Smaller accumulations once thought to be uneconomic can now be produced. In some cases, improvements have also allowed down spacing [additional well(s) in a spacing unit] to occur. Increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). Industry is drilling fewer dry holes and reducing the number of wells needed to fully develop each reservoir. The Energy Information Administration (2007b) has projected the increase in percentage of wells drilled successfully will be 0.2 percent per year to 2030. Their estimate includes wildcat and development wells combined.

From the early 1990's to present, activity has 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 in the Study Area and to determine whether its potential coalbed natural gas resource is economic to produce. Since the risk of failure is higher for these types of activities, the success rates 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 processing capability and speed;
- 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; and
- 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.

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). Also, drilling fewer wells will reduce surface disturbance and volumes of waste, such as drill cuttings and drilling fluids. An added benefit of improved remote sensing technology is the ability to identify oil and gas "seeps" so that they can be cleaned up. These seeps can also help pinpoint undiscovered oil and gas.

Technology improvements have also cut the average cost of finding oil and gas reserves in the United States. Finding costs are the costs of adding proven reserves of oil and natural gas via exploration and development activities and the purchase of properties that might contain reserves. U.S. Department of Energy (1999) estimated finding costs were approximately 2 to 16 dollars per barrel of oil equivalent in the 1970's. Finding costs dropped to 4 to 8 dollars per barrel of oil equivalent in the 1993 to 1997 period. Since that time finding costs have fluctuated around the higher end of this range. During the 2003 to 2005 period, finding costs were 7.05 dollars per barrel of oil equivalent and they increased by 60.9 percent to 11.34 dollars per barrel for the 2004 to 2006 period (Energy Information Administration, 2007a). Most of this increase was reported to have come from a rise in exploration and development spending, which was amplified by a drop in reserves found. Producers have been willing to spend more to find oil and gas since prices received during this period have been higher.

Once hydrocarbons have been found, acquired, and developed for production the cost of operating and maintaining wells and related equipment and facilities is tracked. This cost is referred to as a lifting or production cost. During 2006 lifting costs in the U.S. were 9.09 dollars per barrel of oil equivalent, which was an increase of 20.0 percent from a 2005 cost of 7.57 dollars per barrel (Energy Information Administration, 2007a). Lifting costs have increased in recent years because more producers are willing to spend more to produce oil and natural gas when their selling prices are higher.

FEDERAL DEVELOPMENT CONTRACTS

The United States approves development contracts between operating companies with a number of oil and gas leases sufficient to justify operations for discovery, development, or production of the oil or gas resource. Contracts are approved when the United States determines that conservation of oil and gas products or the public convenience, necessity, or interests of the United States is best served. This program is intended to stimulate exploration on Federal lands. Contracts are usually approved for large, relatively unexplored areas of Federal lands. The contract normally calls for definite exploratory objectives, a timetable for accomplishing those objectives, significant financial expenditures, and it may require a definite drilling obligation. Presently, there are no Development Contracts within the Study Area.

FEDERAL OIL AND GAS UNIT AGREEMENTS

A Federal unit agreement is a contract between the Federal Government and lessees that hold leases over a potential oil and gas reservoir or over oil reservoirs which are candidates for enhanced recovery. Federal units are intended to facilitate the orderly and timely exploration, development, and operation of multiple leases under a single operator. Units may overlie a portion of, or an entire geologic structure. An approved agreement establishes performance obligations, promotes the exploration of unproven acreage or logical enhanced recovery procedures, and permits controlled development of the unit. This process stimulates exploration and/or development of Federal lands and encourages the drilling of the optimum number of wells needed to maximize resource recovery.

Federal oil and gas leases are incorporated into nine unit agreement areas that lie wholly or partly within the Study Area (Figures 8 and 9). All of the unit agreements in the Study Area are secondary (enhanced) recovery units. Five of these are API units in which Federal participation comprises less than 10 percent of the total unit area. The units encompass lands totaling approximately 48,097 acres in area, or approximately 0.19 percent of the total Field Office area. Seven of these unitized areas are located in the

Williston Basin in Harding County (Figure 8). The remaining two areas are in the Eastern Powder River Basin in Fall River County (Figure 9).

All of the active units are oil-productive secondary units. The seven unit areas in Harding County each target the oil-producing Red River Formation; whereas, the two unit areas in Fall River County target oil from the Minnelusa Formation (Leo Sandstone). The earliest of these units was established in November, 1978; the most recent in December, 2004. New units, especially in Harding County, where the majority of the oil and gas activity in the Study Area lies, could be established at any time in the future in response to evolving geological interpretations, improvements in exploration, drilling, and production technologies, or other factors.

No coalbed natural gas units have been established within the Study Area. Future coalbed natural gas exploration in the Study Area is anticipated to be minimal; thus, it is not anticipated that any coalbed natural gas units will be formed during the planning period.

COMMUNITIZATION AGREEMENTS

Communitization Agreements may be authorized when a Federal lease cannot be independently developed and operated in conformity with an established well-spacing or well-development program. In the Study Area, the following circumstances can constitute good reason for communitization to occur.

- Communitization is required in order to form a drilling unit that conforms to acceptable spacing patterns established by State order.
- Adequate engineering and/or geological data is presented to indicate that communitizing two or more leases or unleased Federal acreage will result in more efficient reservoir management of an area.
- Communitization is required when the logical spacing for a well includes both unit and non-unit land.

At present, 48 active communitization agreements lie within the Study Area. All communitization agreements lie within Harding County (Figure 10).

TYPICAL DRILLING AND COMPLETION SEQUENCE

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the South Dakota Department of Environment & Natural Resources, Minerals and Mining Program, Oil & Gas Section (http://www.state.sd.us/denr/DES/Mining/Oil&Gas/O&Ghome.htm). If the well will be located on Federal or Indian Reservation lands, an Application for Permit to Drill must also be approved by the Bureau. Not every approved application is actually drilled. The drilling and completion sequence for a targeted reservoir in the Study Area generally involves:

- constructing the well pad, associated reserve pits, and the access road prior to moving the drilling equipment on to the well location;

- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate the drill bit, which all result in easier penetration of the earth's surface;
- for horizontal boreholes, geosteering (intentional directional control of the borehole based on the results of downhole geological logging measurements) the drill bit to maintain correct hole trajectory and keep a borehole in a particular reservoir to maximize economic production;
- inserting casing and cementing it in place 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 (some laterals are completed open hole, so no perforations are required);
- hydraulically fracturing and propping fractures open with sized particles and/or acidizing the formation to increase permeability and the deliverability of oil and gas to the borehole;
- inserting tubing into each well to allow for controlled flow of fluids (oil, gas, and water) from the reservoir to the surface;
- installing a wellhead at the surface to regulate and monitor fluid flow and prevent potentially dangerous blowouts;
- reclaiming the portions of the well pad and access road that will not be used in the production phase of the well; and
- reclaiming the entire pad and access road after the well has ceased production and is plugged and abandoned.

The cost of developing conventional deposits of oil and gas in the Rocky Mountain region is higher than the average for the onshore 48 contiguous states (Cleveland, 2003). Factors that may contribute to higher costs in the Study Area could be:

- access to well sites is generally more difficult due to remoteness from the main activity areas and sometimes steep terrain,
- lower development priority due to industry focus in other areas (e.g. the Bakken play in North Dakota),
- harsh environments (particularly cold temperatures), and
- labor market conditions.

Drilling improvements have occurred in new rotary rig types, coiled tubing, drilling fluids, and borehole condition monitoring during the drilling operation. Improvements in technology are 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 (see Glossary) 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, and
- better protection of sensitive environments and habitat.

DRAINAGE PROTECTION

Producing oil and gas wells may cause drainage (migration of hydrocarbons toward the borehole) from nearby lands. This drainage will result in the loss of oil and gas from those lands and result in loss of royalty revenues for landowners. Drainage is most often avoided or reduced by the drilling of a protective well. By protecting Federal and tribal lands from drainage the Federal Government may stimulate drilling and development activity in an area and help to insure timely and more efficient management of the producing reservoir.

HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED

Unlike other states in the region, oil seeps were not the first indication of hydrocarbons in South Dakota. Rather, it was natural gas that was first discovered associated with development of water wells. This type of shallow natural gas appears to have been encountered (at probably more than one location) some time before 1890.

Early Exploration and Development Activity

The portion of South Dakota which lies within the Study Area has been of interest to oil and gas developers for over a century. Even though the most prolific production is currently from fields in the southern Williston Basin in Harding County, early exploration centered on and around the Missouri River and the state's capital, Pierre. While these areas today may seem puzzling from a geologic point of view, in a historical perspective neither are surprising. The Study Area in the late 1800s and early 1900s was sparsely populated, much more so than today, and Pierre was one of the few population centers in the state. Additionally, one of the prevailing theories of the time was that oil traps occurred primarily in paleo-river channels; channels thought to generally parallel the course of existing rivers.

Exploring in such a way was not entirely ineffective. Shallow gas was discovered in the 1880s near Pierre and a gas plant was installed to process the gas in 1889 (Steece and McGillivary, 2005). The presence of gas in the area around Pierre and the Missouri River was well documented. In 1917, the State Geologist, Freeman Ward, published the first circular of the South Dakota Geological and Natural History Survey (now the South Dakota Geological Survey). In it, Ward postulated that oil may be present in the area due to the presence of gas associated with wells and springs:

> "Natural gas has been known and used in the state for many years. It is found in some springs and in a large number of artesian wells in the north central part of the state in the region immediately bordering the Missouri River. Because oil and gas have similar origin and because the two so often occur together, the presence of gas very naturally suggest that oil may be in the same region (Ward, 1917)."

One such particular spring well was the Indian School water well of Pierre (Figure 11). Gas from the well was flared continuously from 1892 to 1939 (Steece and McGillivary, 2005). Natural gas from the area was used extensively at the time for municipal needs (e.g., city street lamps) and supplying the Locke Hotel gas for heating, cooking and lighting (Figure 11).

Enough was known at that early time about how certain geologic structures trapped oil and gas that an extensive survey was undertaken by the state survey and Professor J.R. Todd (University of Kansas) along portions of the Missouri River in search of evidence for subsurface structures, specifically domes and anticlines (Ward, 1917). No such evidence was found. Limited gas exploration continued and several more wells were brought online in the Pierre area throughout the first half of the 20th century. Presently, however, there is no commercial gas production from the Pierre area.

The South Dakota Geological and Natural History Survey's fourth circular, published in 1918 was titled "The Possibilities of Oil and Gas in Harding County." Also written by Freeman Ward, the circular summarized the evidence for the presence of oil and gas in Harding County. Ward concluded that "there is a reasonable chance of discovering gas (and possibly oil) in the county (Ward, 1918)." However, it would not be for another 35 years before an oil discovery would be made in Harding, a county that today is the state's richest for oil and gas production.

In October of 1953, Shell Oil drilled the State 34-9 well in Harding County to a depth of 9,332 feet (South Dakota Geological Survey, 2008). The well would be the discovery well for the Buffalo Field, the state's largest (in both production and aerial extent) oil field (Figure 5). The State 34-9 began production in January of 1954. The well is currently listed as inactive (though unplugged) and through 2002 it produced 342,284 barrels of oil, over 2.2 billion cubic feet of gas, and 401,244 barrels of associated water from the Ordovician Red River Formation (Figure 4) (IHS Energy, 2008).

Since 1954, the Buffalo Field has expanded to be the largest field in the state at over 84,820 acres in aerial extent, almost two and one half times as large as the next largest field, Cady Creek. In the decades following discovery at Buffalo Field, a number of additional discoveries were made in Harding County. Presently, there are over 360 active wells in the area adjacent to and including Buffalo Field (IHS Energy, 2008). All but one of the producing wells clustered around Buffalo Field produce from the Red River Formation. The majority of these produce oil, but five currently are producing gas and 26 wells are currently used as injection wells for secondary recovery efforts.

Southwest of Buffalo Field, and also in Harding County, are West Short Pine Hills and Cady Creek Fields (Figure 5). These are the Harding County's only producing gas fields. Discovered in 1977, these wells produce gas from the Cretaceous Shannon and Eagle sandstone members of the Pierre Shale (Figure 4) (IHS Energy, 2008 and Petres, 1989). With nearly 100 producing gas wells, these fields have been continually expanding since discovery. The most recent completion was in January, 2008. Since their discovery, these fields have produced a combined total of over 24 billion cubic feet of gas (IHS Energy, 2008).

In addition to Buffalo, West Short Pine Hills, and Cady Creek fields, there are a number of smaller, associated fields in the area with similar production. There are also over a dozen staked well locations south of the Buffalo Field area and northeast of Cady Creek Field. These locations, all classified as wildcat are targeting gas from the shallow Shannon and Eagle sandstone members of the Pierre Shale (IHS Energy, 2008).

Still in the Williston Basin, but approximately 120 miles to the east of Buffalo Field is the Lantry Field (Figure 6). Discovered in 1970, the Lantry Field is the only field of the Williston Basin portion of the Study Area not in Harding County. Located in western Dewey County, the field has produced over 150,000 barrels of oil from the Red River Formation. Production from the field ceased in 2001 (IHS Energy, 2008).

Recent limited exploratory drilling has occurred approximately 40 miles southeast of Lantry Field, in Stanley County. In 2005, five wildcat wells were drilled south of the Cheyenne River and west of the Missouri River. These wells, each about 10 miles apart, targeted Dakota Group gas (IHS Energy, 2008). Each of the wells was abandoned as a dry hole.

The other large area of oil and gas production in the Study Area lies in Fall River and Custer counties (Figure 7). There are a number of small fields scattered throughout the western portions of these counties (all but one of these are located in Fall River County). The Fall River County fields are all located within the Eastern Powder River Basin. The largest of these, the Indian Creek Field in the southwestern corner of Fall River County, produced both oil and gas from the Pennsylvanian Minnelusa Formation (Leo Sandstone informal member, see Figure 4) (IHS Energy, 2008). Discovered in 1978, the field consists of six wells, all of which are presently inactive. The field has produced 383,928 barrels of oil and over 199 million cubic feet of associated gas.

The next largest field in Fall River County is Alum Creek Field (Figure 7). Discovered in 1981, it also produces primarily oil from the Minnelusa Formation (Leo sandstone). The field reached peak production of 252,601 barrels of oil in 1987, and is still producing today under secondary recovery (IHS Energy, 2008). It is the oldest secondary recovery project in the Study Area. The waterflood (see Glossary) commenced in 1985 and continues to the present (South Dakota Department of Environment and Natural Resources, 2008). The field has produced a total of over 2.5 million barrels of oil and more than 3.6 billion cubic feet of natural gas. East Simms Field, immediately adjacent to Alum Creek to the west also produced from the Minnelusa Formation (Leo sandstone).

The field was discovered in 1984, and produced from a maximum of 5 wells until 1997 (IHS Energy, 2008), with a total production of 351,472 barrels of oil and 85.5 million cubic feet of gas.

A number of other small fields (less than 5 wells each) in Fall River County also produce from the Minnelusa Formation (Leo Sandstone). All of these fields were discovered after 1980.

While the Williston and Eastern Powder River Basins are the top producing areas in the Study Area, one other area bears mentioning. In 1955, the Barker Dome Field was discovered in Custer County. According to Petres (1989), "the discovery marked the successful conclusion to a long running exploration effort on the Barker Dome anticlinal structure and others associated with the Black Hills uplift." Today the field encompasses 2,677 acres with four wells producing oil from the Cretaceous Dakota Sandstone. Since its discovery, the Barker Dome Field has produced 303,719 barrels of oil (IHS Energy, 2008).

Producing Zones

Oil and gas has been produced in only a limited number of formations within the Study Area in geologic formations, or members of formations, which range in age from the oldest producing formation (Ordovician Red River Formation), upward in time to the Upper Cretaceous Eagle and Shannon Sandstone members of the Pierre Shale. The range of producing oil and gas zones is shown in the stratigraphic chart presented in Figure 4.

Ordovician and Cretaceous aged stratigraphic units are the dominant producers in Harding County. In this area the Ordovician Red River Formation produces dominantly oil with minor amounts of gas. The Upper Cretaceous produces gas in this part of the Study Area.

In Dewey County the Ordovician Red River Formation produced oil at Lantry Field (Figure 6).

The Pennsylvanian aged Minnelusa Formation (Leo Sandstone member) is the dominant producing interval in Fall River and Custer counties. It produces oil with minor amounts of gas.

Technology Development

“Technology has historically contributed significantly to the ability of the petroleum industry to find, develop, and produce natural gas resources” (National Petroleum Council, 2003). The National Petroleum Council (2003) postulates that technology improvements will play a lesser role in gas resource enhancement in the 2003-2008 time periods. Technology improvements will play a greater role after 2008 when higher gas prices will motivate industry to invest more in development of technology. Future average improvement rates for certain types of technology are:

- Exploration well success rate 0.53% annual improvement
- Development well success rate 0.46% annual improvement
- Estimated ultimate recovery per well 0.87% annual improvement
- Drilling cost reduction 1.81% annual improvement
- Completion cost reduction 1.37% annual improvement
- Initial production rate 0.74% annual improvement
- Infrastructure cost reduction 1.18% annual improvement
- Fixed operation cost reduction 1.00% annual improvement.

The National Petroleum Council (1999) suggested that access restrictions can add 25 thousand dollars to the average cost of drilling a well in the Rocky Mountains. They also suggested access restrictions delay drilling activity by an average of two years.

Drilling and Completion Activity

There have been approximately 1,574 wells (including horizontal bore holes) drilled in the Study Area (IHS Energy Group, 2008). Of this total, 82 have been sidetracked once, 35 have been sidetracked twice, four have been sidetracked three times, and finally, two were sidetracked four times. Only one well that was sidetracked was plugged back.

Of the 1,574 wells (including horizontal bore holes) drilled in the Study Area, 221 wells, or 14 percent, appear to have been on Bureau managed oil and gas lands and 115 wells, or 7 percent appear to have been on U.S. Forest Service managed lands.

At the close of 2007 there were 201 active producing wells and 38 active injection wells within the Study Area (IHS Energy Group, 2008). All active wells lie within Harding, Fall River, and Custer counties (Figure 1). 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 later date; or
- mechanical difficulties within a borehole prevented economic oil and gas production.

A map of the Study Area shows locations of all 1,574 wells spudded to August 7, 2008 (Figure 2). For this map we considered active wells to be those with an initial completion status of oil, gas, spud, temporarily abandoned, suspended, injection, or service. All other wells we considered to be abandoned. This map shows that drilling has been spread out across the Study Area, with the largest drilling concentrations in Harding and Fall River counties. Many townships have received no drilling activity and many others have had only a few wells drilled. More than 310 townships have had only one or two wells drilled. This is about 70 percent of all townships that have seen some drilling activity. Park Service lands (Figure 3) are closed to oil and gas leasing.

Drilling Rig Counts

Nationwide, rig counts have been increasing since late 2002 (Smith Technologies, 2008). Weekly rig counts for the Study Area generally have followed the national trend (Smith Technologies, 2008). No rigs were working during much of 2002 and one rig began drilling during most weeks, beginning in the middle of October. The average weekly rig count in 2003 rose to 1.15 and then to 1.96 in 2004. The rig count dropped slightly in 2005 (1.81 rigs per week) and then dropped significantly in 2006 (to 0.69 rigs per week). The average weekly rig count began to rise in early 2007 and averaged 1.44 rigs per week. Through the week of July 18, 2008 the average weekly rig count for 2008 was the highest (1.97 rigs per week) during the 7-year period. Since then, the rig count has dropped to zero.

Production

Data from IHS Energy Group (2008) was used to compile cumulative production by field and by operator. Total cumulative production (through 2007) for the Study Area was almost 200 billion cubic feet of gas and about 46 million barrels of oil (Table 1). Of the 485 producing wells in the Study Area at the end of 2007, there were 261 active wells and 224 inactive wells. This production has been from 30 fields and four distinct production zones.

Cumulative water production through the end of 2007 was 105,817,672 barrels (IHS Energy Group, 2008). Total air injected (high pressure air injection for secondary recovery projects) and water injected (for waterflooding or water disposal) was 245,174,520 thousand cubic feet and 24,023,943 barrels respectively (IHS Energy Group, 2008).

Table 1 itemizes the Study Area cumulative oil and gas production by field. Included are the number of wells in each production zone for each field and their respective well status activities. Three of the fields have produced hydrocarbons from more than one production zone. The Buffalo field is the largest producer followed by the West Short Pine Hills dry gas field. The Buffalo field produces oil and gas from the Red River Formation zone and has by far the largest number of active and inactive wells. The West Short Pine Hills Field produces gas from the Shannon Sandstone zone and had 53 total wells of which 45 were active at the end of 2007. Both of these fields are located in the northwest corner of the Study Area, and 20 total fields are located in Harding County in this part of the Study Area (Figure 5).

Nine of the Table1 fields are located in the southwestern corner of the Study Area in Fall River and Custer Counties (Figure 7). The remaining field is located in the southwestern corner of Dewey County (Figure 6).

Dry gas is produced from the Shannon Sandstone and Niobrara Formation production zones (Table1) in the West Short Pine Hills and Cady Creek Fields (Figure 5). The remaining fields are classified as oil fields. The gas-oil-ratio at Buffalo Field indicates that production could be gas-condensate. The abnormally high gas-oil-ratio appears to be due to gas injection into the reservoir for secondary purposes.

Table 2 present's cumulative oil and gas production (through the end of 2007) by operator. Forty-six companies operate producing wells within the Study Area (IHS Energy Group, 2008). The three operators with the highest cumulative gas and oil production are Continental Resources Inc., Luff Exploration Company, and Journey Operating LLC (IHS Energy Group, 2008). Continental Resources Incorporated has produced the largest volumes of both oil and gas. Six operators have only produced gas with eighteen operators only producing oil and another twenty producing both oil and gas. One operator has no reported production.

Continental Resources Incorporated currently has been the most active operator with a total of 211 wells of which 111 were active at the end of 2007 (IHS Energy Group, 2008). Their wells account for about 43 percent of all the wells that active in the Study Area. Hydrocarbons produced by Continental Resources Incorporated account for about 83 percent of the gas and about 54 percent of oil produced.

Luff Exploration Company has a total of 70 wells of which 37 were active at the end of 2007. They are the second most active operator with approximately 14% of all the wells that are active in the Study Area. Luff Exploration Company has produced approximately 1 percent of all the gas and 17 percent of all the oil.

Thirty of the 46 operators had no active wells at the end of 2007, seven operators had 10 or less, five operators had between 11 and 20 active wells, and two operators had twenty-one active wells.

The Red River Formation produced more than 170.7 billion cubic feet of gas through 2007 (IHS Energy Group, 2008). This amounts to about 85 percent of the gas produced in the Study Area. The next largest gas producer is the Shannon Sandstone with almost 24.6 billion cubic feet of gas produced (12 percent of the total gas production), followed by the Minnelusa Formation (Leo Sandstone) with over 4.2 billion cubic feet of gas or about two percent of total gas production. The Niobrara Formation has only produced gas, 130,470,000 cubic feet of gas, or about 0.07 percent of all the gas produced in the Study Area.

The Red River Formation produced 41,136,161 barrels of oil through 2007 (IHS Energy Group, 2008). This amounts to about 89 percent of the oil produced in the Study Area. The Minnelusa Formation (Leo Sandstone) has produced 4,856,154 barrels, or approximately 11 percent of all the oil produced in the Study Area.

The Red River Formation had 359 wells of which 178 were active at the end of 2007 (IHS Energy Group, 2008). The Red River Formation accounted for 73 percent of all wells and 78 percent of all active wells. The Shannon Sandstone had 65 active wells, equating to 24 percent of all active wells and the Minnelusa Formation (Leo Sandstone) had 19 active wells, equating seven percent of all active wells. The Niobrara Formation had only two wells of which one was active.

Yearly oil and gas production rates (Figure 12) and cumulative oil and gas production rates (Figure 13) are graphed to illustrate historical volume rates and cumulative volumes of oil and gas as a function of time from 1954 through 2007 (IHS Energy Group, 2008). The various changes or trends in the shapes of these curves are the result of the same market forces that have impacted all production everywhere in the world. The only difference between the Study Area and the rest of the world would be the magnitude of the numbers. Historically, producers primarily only had an interest in oil. This changed with the 1973 Oil Crisis and the raised consciousness of the impact of oil on the environment. The Arab members of the Organization of Arab Exporting Countries, reduced oil supply which created a worldwide oil shortage. As a result, exploration activity increased in the United States, and after a lag of several years production began to increase. As the Study Area's yearly production rate for oil in the Figure 12 graph demonstrates, production increased from 200,000 barrels per year in 1970 to 1,600,000 barrels per year in 1984. This translates to a yearly production rate increase of approximately 100,000 barrels per year for the Study Area. Conservation, alternative energies, and numerous other interacting factors eventually resulted in a glut of oil that is reflected in the 1984 oil production rate flattening out at about 1,600,000 barrels per year. With the glut of oil came a sharp market correction in oil price from a high of about 80 dollars per barrel in the early 1980s to about 20 dollars per barrel in 1987 and prices stayed very low until late 1999.

The impact of inflation on the costs associated with producing oil combined with cheap oil imports resulted in a contraction and restructuring of the oil business in the United States beginning in the middle 1980s. Small producers operating in isolated areas, such as the Study Area, were forced to sell off or shut in existing production. This is reflected in the decreased production rate illustrated in the graph from about 1990 to 2000. Many operators in the Rockies were selling properties and heading offshore in the Gulf of Mexico taking advantage of royalty relief incentives to find and produce hydrocarbons in deep water. Since 2000, the oil production rate for South Dakota has rebounded and exceeded the 1,600,000 barrel per year rate of the early 1980s. This may be due in large part to the emerging economies of China and India as they require huge volumes of imported hydrocarbons to expand and increased demands for oil have caused significant increases in the price of oil.

A historical 5-year epoch oil production graph (Figure 14) shows that oil wells completed from 2005 through 2007 account for about 55 percent of present production. Wells completed in the period from 2000 to 2004 are now only producing about 21 percent of the today's total production. Wells drilled from 1985 to 1999 have significantly declined and are only producing about 10 percent of today's total production. Wells drilled from 1970 to 1984 are now producing the remaining 14 percent of the total gas produced.

The gas production rate curve for South Dakota (Figure 12) shows that yearly production started to climb steadily, beginning in 1978. In 1978 the gas production rate was very low but now it stands at about 12 billion cubic feet per year. This averages out to a growth rate of about 4.1 million cubic feet per year. In the late 1970s, oil for space heating was expensive and many homes converted to natural gas. Gas burns clean and is the preferred alternative, given the option. An ever expanding gas pipeline network has enabled remote isolated producers, such as those in the Study Area, to get their product to market. Natural gas is a non-renewable energy alternative that complements renewable energies such as wind and solar with respect to the environmental issue. The cumulative gas production graph (Figure 13) grew exponentially starting in 1978 and up to 2001, and has since exhibited linear growth.

A historical 5-year epoch gas production graph (Figure 15) shows that gas wells completed from 2005 through 2007 account for about 58 percent of present production. Wells completed in the period from 1985 to 2005 are only producing about 25 percent of today's total production. Wells drilled from 1975 to 1979 are now producing the remaining 17 percent of the total gas produced.

<u>Coalbed Natural Gas</u>

Presently, there is no coalbed natural gas production in the Study Area, nor are there any ongoing exploration activities. Figure 16 shows the Study Area with mapped areas of known coal bearing strata (U.S. Geological Survey, 2001a and 2001b). The Study Area lies within the Fort Union and Black Hills coal regions. The Fort Union coal region contains lignite coals (Tertiary and Cretaceous) and the Black Hills coal region contains medium and high volatile bituminous coals. Wood and Bour (1988) reported some information about these coal regions. They found that the Fort Union Coal Region contains up to 20 coal beds greater than 30 inches thick and at depths less than 2,000 feet. Few coals are known to exceed a thickness of 10 feet. Rothrock (1947) mapped operating and abandoned coal mines, and coal outcrops in northwestern South Dakota.

Some preliminary coal coring tests have reportedly occurred in North Dakota, but no data is available. Currently, the Plains CO_2 Reduction Partnership is evaluating the efficacy of carbon sequestration through injection of carbon dioxide into an unminable lignite coal seam in northwestern North Dakota (Plains CO_2 Reduction Partnership, 2008, and U.S. Department of Energy, 2007). A test pod of five wells were drilled in August of 2007, in Burke County and are classified by the North Dakota Industrial Commission (2008) as exploratory coalbed natural gas wells. If successful, the results of the study could provide future incentive to coalbed natural gas producers in South Dakota when and if coalbed natural gas reserves are discovered through more extensive exploratory drilling programs.

<u>Marginal Wells</u>

Low-volume oil and gas wells yield an important percentage of hydrocarbons produced in the U.S. During 2003, about 29 percent of crude oil production and more than 10 percent of natural gas production was credited to marginal wells (Duda and Covatch, 2005). Producing oil or natural gas wells are considered to be "marginal" when their producing rate is at the limit of profitability. The Interstate Oil and Gas Compact Commission (IOGCC, 2006) and the South Dakota Department of Environment and Natural Resources (McGillivray, 2008b) each define marginal or stripper wells as wells that are producing 10 (or less) barrels of oil per day or are producing less than 60,000 cubic feet per day of natural gas. Most recent data of the IOGCC shows that marginal oil wells produced 17.2 percent of U.S. production and marginal gas wells produced 9.2 percent during 2005 (IOGCC, 2006).

The majority of marginal wells are owned, maintained, and produced by independent operators rather than integrated exploration and production firms which operate globally. They account for a large proportion of the jobs and corresponding economic growth associated with the petroleum industry in this country (Duda and Covatch, 2005). In addition, as long as these wells remain productive there are additional opportunities to use advanced technology to enhance recovery.

In 2005, South Dakota ranked 26th of the 28 major producing states in the number of marginal oil wells (IOGCC, 2006). According to the South Dakota Department of Environment and Natural Resources, in 2007 there were 30 marginal oil wells that produced 63,054 barrels of oil (South Dakota Department of Environment and Natural Resources, 2008b). Marginal well production amounted to approximately 3.8 percent of total South Dakota crude oil production, and almost 70 percent of all secondary oil production. In 2005, South Dakota's marginal oil well reserves from 24 wells were estimated to be 154,000 barrels from primary production and 149,000 barrels from secondary production (Moritis, 2005). From 2005 to 2007 the number of marginal oil wells in South Dakota increased by 20 percent (from 24 to 30 wells).

In 2005, South Dakota ranked 26th of the 28 major producing states in the number of marginal gas wells (IOGCC, 2006). According to the Environment and Natural Resources, in 2007 there were 63 marginal gas wells that produced 399,907 million cubic feet of gas (South Dakota Department of Environment and Natural Resources, 2008b). Marginal well production amounted to almost 95 percent of total South Dakota gas production. From 2005 to 2007 the number of marginal gas wells in South Dakota, increased by over 10 percent (from 56 to 63 wells).

In 2005, the state received 130,049 dollars in marginal oil production tax revenue (IOGCC, 2006).

<u>Deep Well Drilling: Greater than 15,000 feet</u>

Dyman, et al. (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to vertical depths greater than 15,000 feet. Drilling and completing deep gas wells are very costly due to the extremely high temperatures and pressures and hard rock encountered. Dyman, et al. (1997), do not report the presence of sedimentary rocks at depths greater than 15,000 feet anywhere within the Study Area. No wells drilled in the Study Area have exceeded 15,000 feet vertically (IHS Energy Group, 2008 and South Dakota Department of Environment and Natural Resources, 2008a).

<u>Deep Well Drilling and Completion Activity: 10,000 to 15,000 feet</u>

There appears to be sedimentary rocks in the 10,000- to 15,000-foot depth range within the Study Area. No wells drilled in the Study Area have exceeded 10,000 feet vertically (IHS Energy Group, 2008 and South Dakota Department of Environment and Natural Resources, 2008a). A number of horizontal wells exceeded 10,000 feet in measured depth, but true vertical depth for these wells was always less than 10,000 feet.

<u>Well Drilling and Completion Activity: 0 to 10,000 feet</u>

Figure 17 portrays the range of drilling depths of all vertical wells and all deviated wells (directional or horizontal) with a recorded true vertical depth, within the Study Area. Drilling depths are shallow in this region. About 66 percent of all wells have been drilled to 5,000 feet or less, with the majority of those wells drilled in the 1,001 – 3,000-foot depth range. The remaining 34 percent of all wells have been drilled in the 5,001- to 10,000-foot depth range, with the majority of those wells drilled in the 8,001 – 9,000-foot depth range. The deepest well was drilled to 9,771 feet.

The north portion of the Study Area lies in the southern end of the Williston Basin, which contains the thickest section of sedimentary rocks in the Study Area. The north part of Harding County contains most of the wells drilled to depths of more than 5,000 feet (Figure 18), with the deepest well drilled to 9,771 feet. The leading target of drilling in this area has been the Ordovician Red River Formation. In the north portion of the study area four other counties have had a majority of tests drilled below 5,000 feet. The deepest vertical borehole penetration in each of these four counties has been:

- Perkins County – 9,433 feet,
- Corson County – 8,445 feet,
- Ziebach County – 6,410 feet, and
- Dewey County – 6.325.

Other counties with a minor number of tests below 5,000 feet and the deepest well penetration are:

- Butte County – 7,772 feet,
- Meade County – 6,910 feet,
- Fall River County – 6,067 feet,
- Bennett County – 5,800 feet
- Pennington County – 5,575 feet, and
- Haakon County 5,556 feet.

Figure 19 portrays the range of drilling depths of all vertical wells and all deviated wells (directional or horizontal) with a recorded true vertical depth, that were completed as producing wells, within the Study Area. The largest numbers of producing wells (53 percent) were drilled in the 8,001 – 9,000-foot depth range, followed by the 1,001 –

2,000-foot depth range with 23 percent, and the 9,001 – 10,000-foot depth range with 11 percent. The deepest well was drilled to 9,771 feet and produces from the Red River Formation.

Producing wells, with depths greater than 5,000 feet, occur only in Harding and Dewey counties (Figure 20) and all produce from the Red River Formation. The deepest producing well in Harding County is 9,771 feet and in Dewey County it is 5,099 feet. Producing wells, with depths less than 5,000 feet, are located in southern Harding County and in Butte, Custer and Fall River counties. In Fall River County the deepest producing well is 4,431, in Custer County it is 1,928 feet, and in Butte County it is 1,500 feet. Production from these shallow wells is predominately from the Shannon Sandstone and the Minnelusa Formation (locally called the Leo Sandstone).

Summary of Current Drilling Techniques and Trends

Developments in drilling techniques have allowed for more widespread use of directional and horizontal drilling (see Glossary for directional and horizontal drilling) technology. Directional drilling has many benefits, but also limitations. For instance, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a well bore contacts a producing formation, and, when multiple directional well legs are drilled from the same vertical well bore or from the same surface location, reduce drilling time, associated waste volumes and emissions, and provide greater protection of sensitive environments (Carr, et al. 2003).

Directional and Horizontal Drilling and Completion Activity

In addition to the benefits of directional and horizontal drilling outlined above, such wellbores will often be allowed to move in an updip (see Glossary) direction along the flanks of geologic structures (e.g., along the axis of a plunging anticline), thereby naturally contacting more of the producing formation. Directional wells also have the benefit of providing the operator with the option of drilling multiple wells from the same location, substantially reducing the surface disturbance and potentially avoiding environmentally sensitive areas.

Drilling and completion costs for directional and horizontal wells are typically significantly higher than for conventional vertical boreholes, even when the cost savings associated with reduced need for surface disturbance is taken into account. Eustes (2003) and Fritz and others (1991) identified the following specialized requirements and risk factors unique to horizontal and directional drilling that can affect drilling and completion costs for these types of wells:

- specialized equipment [e.g., mud motors (see Glossary), measurement while drilling tools] and specially trained personnel,
- a larger drilling rig and associated equipment,
- casing and drilling string modifications to address problems associated with ovality (see Glossary) and bending stresses,

- increased risk of borehole damage due to unique tectonic stresses,
- slower penetration rates lengthens overall drilling time on location, and/or
- increased torque and drag on borehole equipment.

In addition to increased costs, the risk of losing the well due to geologic and/or mechanical failures is also greater in directional and especially horizontal boreholes than in conventional vertical boreholes. As a result of these increased costs and risk, operators tend to prefer vertical over directional or horizontal boreholes unless special circumstances exist that make such drilling a necessity or economically attractive. As an example, the geology of a reservoir may be such that a vertical borehole may only contact a few feet of the productive horizon, while a horizontal borehole may be able to contact tens to thousands of feet depending on factors such as how the well is completed and the areal extent of the pool. In a case such as this, the operator must make the determination that the increased potential for productivity outweighs the inherent risks involved in directional and horizontal drilling.

The majority of oil and gas wells in the Study Area have traditionally been drilled vertically, but recent activity in the Red River Formation in Harding County has reversed this trend. Of the 189 wells spudded between January 1998 and December 2007, only 61 were vertical wells, with the remainder being horizontal (117) or directional (11) (IHS Energy Group, 2008) (Figure 21). In 2007, only seven of the 41 wells spudded, were vertical. The vertical wells producing in the Study Area are completed in a variety of formations for both gas and oil. Productive horizons span the shallow Cretaceous Eagle Formation to the deeper Ordovician Red River Formation, with wells located in Dewey, Fall River, Custer, and Harding counties. By contrast, all of the currently producing horizontal and directional wells in the Study Area are producing oil from the Red River Formation, and all are located in Harding County.

True vertical well depths in the Study Area range from a few hundred feet in the Powder River Basin, in the southwestern corner of the state (Fall River County), to over 9,771 feet in the Williston Basin in Harding County to the northwest. The deepest producing vertical well drilled to date is the Luff Exploration Company, Dworshak # 1-19. This well produced oil from the Red River Formation and is now plugged and abandoned. It was spudded in 1976 and it was abandoned in 1995, after producing 195,784 barrels of oil and 81,764,000 cubic feet of gas. By comparison, the longest horizontal well is the Prima Exploration Incorporated, SBRRU 42-6H. It was drilled to a measured depth of 17,025 feet, with the horizontal leg exceeding 7,000 feet. The well was completed in May of 2006 as an injection well in the Red River Formation in Buffalo Field.

Successful productive well completion rates from January 1998 to December 2007 for directional and horizontal wells in the area were 97.6 percent (IHS Energy, 2008). It should be noted that when viewed separately over the same time period directional and horizontal wells have completion rates of 100 percent and 97.4 percent, respectively. These rates are in stark contrast to the completion rate of 32.7 percent for vertical wells during that same time. This low completion rate for vertical wells is likely related to the fact that all but one of the dry and abandoned wells were exploratory wells targeting gas in the shallow Leo, Eagle, Dakota, and Shannon formations. The significantly higher success rate for horizontal wells compared to vertical wells is likely influenced by two additional factors. First, the density of existing vertical wells in the areas where horizontals are concentrated has provided increased geologic knowledge of the reservoir, thereby increasing the likelihood that a horizontal well is drilled into a productive formation. Second, horizontal wells are often part of sets of multiple lateral boreholes off an initial vertical wellbore. The success of the first lateral increases the chance of success of subsequent laterals from the same wellbore.

The earliest known directional well, the Pawnee Oil Company, Milo Downing 1-P in Harding County was drilled and abandoned in April, 1991 (IHS Energy Group, 2008). The well was targeting oil in the Red River Formation. The well was located approximately 23 miles north-northeast of the town of Buffalo in Harding County.

The earliest horizontal well drilled was the Meridian Oil Inc., East-Buffalo Federal 14-30. The well was spudded in December of 1988 and abandoned five months later after reaching a total drilled depth of 10,042 feet. The well was a wildcat exploration well with oil shows in Harding County targeting oil in the Red River Formation. The horizontal portion or the well bore had 1,178 feet of offset to the northeast from the surface location.

Only one directional well was drilled from 1992 through 2005. However, although no horizontal wells were drilled in the years 1989 through 1993, the frequency of horizontal wells drilled increased dramatically beginning in 1994. From 1994 through the end of 2007, a total of 140 horizontal wells were drilled in the Study Area. All of these wells targeted the Red River Formation oil. Figure 22 clearly shows the frequency of horizontal wells spudded from 1994 through 2007. There are two moderate peaks in 1996 and 2000, and beginning in 2004 the frequency increased dramatically. As all these wells have been drilled to the Red River Formation, it is difficult to isolate the reasons behind the first two peaks. However, the upward trend which started in 2004 and continues to the date of this writing is likely related to the sharp increase in the price of oil, as well as advancements in horizontal drilling technology in the area associated with the Bakken Formation play of North Dakota and Montana.

Ninety horizontal and directional wells were producing oil or gas at the end of July of 2008, with many others in a shut-in status. Of the 90 producing wells, 53 were operated by Continental Resources, 29 by Luff Exploration, 5 by Prima Exploration, 2 by Murex Petroleum, and 1 by Citation oil and gas. Of the 90 producing wells, 88 were classified as oil wells and only 2 as gas wells, and all were producing from the Red River Formation in Harding County (IHS Energy, 2008). Citation, Continental, Luff, and Prima operated an additional 12 horizontal wells and 1 directional injection well: all being used in secondary Red River oil recovery projects in Harding County.

Horizontal drilling depths (measured depth) in the Study Area range from 7,950 to 17,025 feet. However, most of these wells have a measured depth that is within the

10,000 to 13,000 foot range; directional wells range from 8,640 to 14,900 feet in measured depth, with most falling in the 10,000 to 12,000 foot range.

Reverse Circulation Drilling

Reverse circulation drilling uses a dual-wall drill string. Drilling fluid is carried to the bit between the outer and inner wall of the drill pipe and cuttings and fluid are returned to the surface in the inner part of the pipe. Reverse circulation drilling appears to be an ideal system for drilling and producing tight low- or under-pressured formations that could be easily damaged by conventional drilling. K2 Energy of Calgary has applied this technology to successfully drill and test gas wells in the low-pressure (formation pressure estimated at 150 pounds per square inch) Bow Island Formation on the Blackfeet Indian Reservation and in the Montana Thrust Belt (Mackay, 2003).

Slimhole Drilling and Coiled Tubing

Slimhole drilling (see Glossary), a technique used to recover reserves in mature fields, has not yet been used much in the Rocky Mountain Area. It has the potential to improve efficiency and reduce costs of both exploration and production drilling. Coiled tubing (see Glossary), used effectively for drilling in reentry, underbalanced, and highly deviated wells is often used in slimhole drilling. Most coiled tubing rigs are limited to relatively shallow drilling. Study Area wells have been historically drilled to shallow depths, with about 70 percent drilled to 5,000 feet or less. A review of coiled tubing intervention and drilling and its advantages, disadvantages, and limitations was presented by the U.S. Department of Energy (2005). Most likely, future applications may be for drilling shallow development wells (including coalbed natural gas wells), reservoir data monitoring holes, shallow re-entry wells, and deeper exploration holes (Spears & Associates, Inc., 2003). Brown (2006) has reported that slimhole drilling with coiled tubing may soon begin to replace conventional rotary drilling in the shallow depths across the United States. He reported that cost savings can range from 25 to 35 percent per hole, and other advantages include:

- good hole quality,
- improved safety,
- minimal cuttings, and
- reduced chance of damaging underpressured formations.

Coiled tubing will most likely be first used in some workover situations in the Study Area. 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, and
- protection of sensitive environments.

Light Modular Drilling Rigs and Pad Drilling

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. Use of this type of rig within the Study Area is not likely in the near future. Other Rocky Mountain play areas, in North Dakota and in western Wyoming and western Colorado, have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than within the Study Area.

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 and cost to drill. Shallow drilling targets in the Study Area are not conducive to the use of significant amounts of directional drilling so pad drilling would be unlikely in the area.

Pneumatic Drilling

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 to the fluids commonly used in drilling. Many fields in the Study Area meet these criteria. It is an important tool that can be used when drilling horizontal wells, so it could be used in those types of situations in the future. This type of drilling significantly reduces waste, shortens drilling time, cuts surface disturbance, 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 within the Study Area. In the future, use of this type of drilling system may become more widespread and may be used when drilling other types of directional boreholes.

Improved Drill Bits

Advances in materials technology and bit hydraulics have yielded tremendous improvement in drilling performance. Latest-generation polycrystalline diamond compact bits drill 150 to 200 percent faster than similar bits just a few years ago (U.S. Department of Energy, 1999). 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, and
- less noise.

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

Summary of Current Completion Techniques

Standard completion techniques for the Study 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 can enhance well performance, minimize drilling, and allow the recovery of otherwise inaccessible oil and gas resources. The flow of hydrocarbons is restricted in some low-permeability, tight formations and in nonconventional reservoirs (such as coalbed natural 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 keeps 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.

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.

Drilling and Completion Costs

The National Petroleum Council (2003) reported drilling and completion costs for the Williston/Northern Great Plains region. They reported that the average oil well drilling and completion cost for wells to depths of 5,000 feet was 280 thousand dollars. Wells in the 5,000 to 10,000 foot range cost an average of 955 thousand dollars to drill and complete. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations were assumed to be included in these costs.

For gas wells, the National Petroleum Council (2003) reported an average cost for wells to depths of 5,000 feet was 83 thousand dollars. Most Study Area producing wells in this range have been drilled to depths of only 1,001 to 2,000 feet (Figure 19). Wells in the 5,000 to 10,000 foot range cost an average of 571 thousand dollars to drill and complete. Most Study area producing wells, in this range, have been drilled to depths of 8,001 to 9,000 feet (Figure 19).

The National Petroleum Council (2003) also reported dry hole well costs. They were 100 thousand dollars for average wells to depths of 5,000 feet and 506 thousand dollars for wells between 5,000 and 10,000 feet deep.

Drilling costs have increased since the National Petroleum Council published their 2003 report. Operators in the Rocky Mountain region have been faced with increases in both drilling and completion costs. Drilling rates have increased 20-50 percent (Rocky Mountain Oil Journal, 2005) and service costs have also increased. Rig shortages have affected most areas of the region. Reasons why new Study Area wells may be more expensive to equip and operate are:

- remoteness and cold temperatures, which often requires dehydrators and line heaters, more expensive types of steel casing, and insulation of surface equipment;
- workovers and preventive maintenance is more frequent, which minimizes shut-in days in the winter when well site access is difficult;
- and
- oil and gas price increases have increased the demand for rigs;
- lack of rig availability due to a lower drilling priority relative to the nearby large Bakken play in North Dakota.

Recent drops in oil and gas prices have resulted in at least a short-term decrease in rig demand and will lead to some reductions in drilling and completion costs. These reductions in rig demand and costs are expected to only be in effect for a few years into the future.

SUMMARY OF PRODUCTION AND ABANDONMENT TECHNIQUES

Once production begins application of reservoir management procedures are needed to ensure maximum hydrocarbon production at the lowest possible cost, with minimal waste and environmental impact. In earlier days, recovery was only about 10 percent of the oil-in-place 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-in-place. Also, 75 percent or more of the natural gas-in-place in a typical reservoir is now recovered. Operators have also taken significant steps in reducing production costs. U.S. Department of Energy estimated that costs of production had decreased from a range of 9 to 15 dollars per barrel of oil equivalent in the 1980's to an average of about five to nine dollars 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 most recent reserve additions in the Study Area have come from existing fields and horizontal drilling. Very few new wildcats have been drilled indicating the mature nature of oil and gas plays within the Study Area.

Recovering oil and gas from a geologic reservoir often occurs in a staged process using different recovery techniques (or a combination of techniques) as the reservoir is drained. Traditionally, processes were referred to as primary, secondary, or tertiary depending on when the process was applied. However, as technology has improved and the price of oil and gas has increased, reservoirs that had previously been bypassed are now being tapped using secondary or tertiary processes from the outset. Therefore, the terms "secondary" and "tertiary" are seeing less usage, or are more narrowly defined. "Secondary recovery" has become synonymous with water flooding and gas (not carbon dioxide) injection and "enhanced recovery" broadly encompasses any recovery techniques that are not part of primary recovery or waterflooding. The following definitions will be used in this report:

- <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 extend productive life when a reservoir's natural pressure dissipates.
- <u>Secondary Recovery</u> – Stimulation of reservoir production via injection of water into the producing formation thereby driving oil to production wells, or via injection of gas to expand the gas cap and/or regulate the reservoir pressure.
- <u>Enhanced Oil Recovery</u> - Injection of fluids (e.g., water, 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.

According to the Department of Energy, as much as 90% of the oil originally in place in an oil reservoir is left behind once primary recovery methods are completed (U.S. Department of Energy, 2008). In other words, the recovery factor (the percent of original oil in place removed from a reservoir) for primary recovery can be as low as 10%. However, the primary recovery factor varies depending on oil and reservoir characteristics, but as a general rule 15-20% is considered the norm (Sandrea and Sandrea, 2007). Primary recovery relies on the natural pressure found in the reservoir to bring hydrocarbons to the surface for production. Once that pressure is depleted, the reservoir must either be abandoned or other methods for recovering additional hydrocarbons must be employed. Historically, many secondary and enhanced oil recovery methods were cost prohibitive and a large percentage of the oil or gas in any given reservoir was left behind for future recovery.

As new discovery volumes decline and demand, and consequently price, for oil and gas continues to climb, methods for removing more of the oil and gas left behind by primary recovery methods are becoming increasingly utilized. These secondary and enhanced recovery methods all involve some form of artificial stimulation of the reservoir either through the regulation of reservoir pressure or gas cap, or by physically "pushing" the oil toward production wells.

Secondary Oil Recovery

The secondary recovery methods most widely used both historically and today are waterflooding and gas injection (Sandrea and Sandrea, 2007; Williams and Pitts, 1997). In waterflooding, water is injected into the oil-bearing formation and physically displaces, or sweeps the oil toward the production wells. Waterflooding is an economical way to recover additional volumes left behind in the primary recovery process and is usually the first method considered after primary methods have ceased to be effective. Gas injection (as a secondary recovery method) is used to both expand the gas cap and regulate the reservoir pressure of an oil reservoir, or to displace oil immiscibly, i.e., physically pushing the oil toward production wells (Green and Whillhite, 1998). Once secondary recovery is no longer effective in improving recovery factors (or, if they were deemed inappropriate due to reservoir and hydrocarbon characteristics) enhanced recovery methods must then be considered.

Enhanced Oil Recovery

Enhanced oil recovery projects are initiated because of the limited production efficiency of primary and secondary recovery projects (Williams and Pitts, 1997). Green and Whillhite (1998) identified five general enhanced oil recovery categories: mobility-control, chemical, miscible, thermal, and "other" processes (e.g., microbial). With the exception of "other" methods (which is generally a catch-all used for methods that do not fit the other categories) these methods all involve the injection of fluids (e.g., water, 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. As with secondary recovery injection methods, enhanced recovery injection causes an increase in pressure gradient between injection wells and production wells, increasing the tendency of oil in the reservoir to flow toward the production wells. Many injection fluids also have additional chemical or physical effects that help mobilize the oil and allow it to be swept towards production wells (Nummedal et. al., 2003).

Williams and Pitts (1997) reported that locale can also 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 steamflood or chemical projects. Oil and gas prices play a very important role in determining whether an enhanced oil recovery project will be viable, and deciding what type of recovery project would be appropriate. There are a large number of older oil fields within the Study Area, and a number of different types of enhanced oil recovery projects have been used to increase production. Water floods have been the predominant method of increasing oil recovery and fewer floods of different types have been used.

Secondary and Enhanced Recovery Projects in South Dakota

Waterflooding and Gas Injection

Waterflooding incrementally increases the recovery of reserves that would otherwise not be produced. It typically yields an extra 10 to 25 percent recovery of the original oil in place (Nummedal et. al., 2003). Many South Dakota oil reservoirs are good candidates for waterflooding and waterfloods have been the predominant method used to recover additional oil reserves.

Gas injection typically refers to the re-injection of produced natural gas into an oil producing formation (as opposed to disposal injection into another formation). In today's market, most produced natural gas is sold rather than re-injected.

There are currently five active waterflood projects located in oil fields throughout the Study Area, and these projects represent the bulk of any secondary or enhanced recovery efforts in the Study Area (Table 3); however, there are no active gas injection projects.

The Alum Creek Unit operated by Citation Oil in Fall River County (Figure 9) is the oldest existing waterflood and natural gas injection project in the Study Area (McGillivray, 2008a). The field produces oil and natural gas from the Minnelusa and 2nd Leo formations. Reinjection of natural gas began in November of 1982, with the waterflood commencing shortly thereafter in March of 1985. Over 10 million barrels of water and 2 billion cubic feet of gas have been injected as of July 2008. The field was online for less than a year before gas reinjection began and produced a total of 36,865 barrels of oil prior to secondary recovery efforts (IHS Energy Group, 2008). Since that time, the Alum Creek field has produced over 2,500,000 barrels of oil and 3.4 billion cubic feet of gas (re-injection of produced gas ceased in 1995). Annual production from the field has been in a steady decline since injection began. In 1982, over 246,000 barrels of oil and 326 million cubic feet of gas were produced. By contrast, only 17,098 barrels of oil and 3.8 million cubic feet of gas were produced in 2007.

The largest active waterflood project (by total well count) in the Study Area is the West Buffalo "B" Red River Unit in Harding County (Figure 8). It is operated by Citation Oil (McGillivray, 2008a). As the name suggests, the field produces oil from the Red River "B" Formation. There are presently seven water injection wells and seven production wells in the unit within the larger Buffalo Field (which has a total of six active secondary and enhanced recovery projects – three waterflood and four in-situ combustion projects). The West Buffalo "B" Red River Unit waterflood project began in 1987, and has produced a cumulative total of over 1.8 million barrels of oil. There are three additional waterflood projects in the Study Area, each in Harding County, and each producing from the Red River "B" Formation. These include the Central Buffalo Red River Unit operated by Prima Exploration, and the North Buffalo Red River and East Harding

Springs Red River Units each operated by Luff Exploration. Together, these three units have produced in excess of 5.3 million barrels of oil.

Steamflooding

Steamflooding uses heat to mobilize oil and is especially applicable to heavy (viscous) oils that are not easily produced just by pumping. Steam injection into an oil reservoir under pressure thins the oil (lowering viscosity) and increases pressure which helps push the oil toward nearby producing wells. Currently, there are no active steamflooding injection projects located in the Study Area.

Polymer-Enhanced Waterflooding

Polymer-enhanced waterflooding is used to control mobility of injected water. It improves sweep efficiency (see Glossary) and reduces channeling and breakthrough (see Glossary); hence it improves overall recovery. Currently, there are no active polymer-enhanced waterflooding injection projects located in the Study Area.

Surfactant Flooding

Adding surfactants to injected water can enhance oil production. A surfactant offers a way to recover residual oil by reducing the surface tension between the oil and injected water phases. A very low oil-water surface tension reduces the capillary pressure and allows the water to displace extra oil towards the borehole. These types of projects are expensive and have not been reported within the Study Area.

In-Situ Combustion (High Pressure Air Injection)

The terms in-situ combustion and high pressure air injection are used synonymously to describe the process by which pressurized air is injected into hot and deep reservoirs causing spontaneous oxidation/combustion of the oil (Manrique, et al. 2006). The term "thermal process" is also a catch-all sometimes used to describe these as well as hot-water and steam floods (Green and Willhite, 1998), but will not be used here as each recovery method is discussed separately. During in-situ combustion, oxygen (as atmospheric air or in a partially purified mixture) is continuously injected under pressure either by itself (dry) or with water (wet) into the reservoir where spontaneous or artificially initiated combustion causes the lighter hydrocarbons to vaporize and be pushed away from the high pressure injection site toward the producing wells. Air injection works well on these types of heavy oil reservoirs. It is much more cost effective than other enhanced oil recovery methods like carbon dioxide injection, since the gas is usually atmospheric air, and is free.

There are presently three in-situ combustion enhanced recovery projects in the Study Area, each operated by Continental Resources, Inc (McGillivray, 2008a). These are the Buffalo, West Buffalo, and South Buffalo Red River units in Harding County (Figure 8), each producing from the Red River "B" Formation. The first of these projects, the

Buffalo Red River Unit, began injection in 1979 (then operated by Koch Oil Company) and is still operated today. Today there are 18 producing wells, and five injectors. The unit currently produces approximately 525 barrels of oil per day and has produced a cumulative total of 7.8 million barrels (Koottungal, 2008, and McGillivray, 2008a).

The West Buffalo Red River Unit began in-situ combustion in 1987. It is the smallest of these three projects (both by surface acreage and number of wells). From a total of four injection and 11 production wells, the unit produces an average of 425 barrels of oil per day. The unit's cumulative production as of July, 2008 is 3.9 million barrels of oil.

By far the largest of these projects is the South Buffalo Red River Unit. It is also the largest of any secondary or enhanced recovery project (by surface acreage, well count, and production) in the Study Area. Encompassing 20,800 acres, the unit is injecting from a total of 13 wells and has 37 producing wells online. The project began in 1984, and has produced a cumulative 12.1 million barrels of oil with a current rate of approximately 975 barrels per day.

Carbon Dioxide Injection

At sufficiently high pressures carbon dioxide is miscible with oil, and once dissolved, carbon dioxide:

- Causes oil to swell, and so lowers the oil’s viscosity significantly, making it flow more easily and
- Under miscible conditions, it reduces forces causing oil to stick to the reservoir rock, again allowing for more oil flow.

Carbon dioxide enhanced recovery processes are typically employed in one of four ways:

- the "huff and puff" method whereby the carbon dioxide is injected, allowed time to physically interact with the oil, resulting in a reduction in its viscosity and increasing its flow rate towards the borehole and is followed by pumping in three separate stages,
- injection of a carbon dioxide "slug" followed by water injection and then pumping,
- pulses of carbon dioxide alternated with water pulses (so-called water-alternating-gas method), or
- continuous carbon dioxide injection with concurrent pumping.

There are currently no carbon dioxide enhanced oil recovery projects in the Study Area; however, such projects are becoming increasingly used throughout the United States and are receiving attention as ways to also sequester carbon dioxide in geologic formations. However, due to the limited size and scope of the fields in the Study Area, lack of a carbon dioxide pipeline or local source, and the success of the lower capital investment in-situ combustion projects, the likelihood of any carbon dioxide enhanced recovery projects beginning during the scope of this document is low.

Acid Gas Removal and Recovery

Before natural gas or oil can be transported safely, any hydrogen sulfide or carbon dioxide gas must be removed. Special plants are needed to separate the unwanted gases from the hydrocarbons and thereby sweeten the hydrocarbon product for sale. Improvements in the process have made it possible to produce sour natural hydrocarbon resources, almost eliminate noxious emissions, and recover almost all of the elemental sulfur and carbon dioxide for later sale or disposal. The majority of hydrocarbon production in South Dakota is in the form of oil, and there are currently no acid gas removal plants in the Study Area.

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 in artificial lift have enhanced production, lowered costs, and lowered power consumption, which reduce air emissions. Artificial lift is used to recover oil from some of the fields in the Study 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.

Produced Water Management

The South Dakota Department of Environment and Natural Resources regulates produced water management practices. Applicable state regulations are 74:10:05:13 (disposal of produced water), which allows water produced with oil and gas to be disposed of by injection in a permitted disposal or enhanced recovery well, evaporation in an approved pit, or discharge into a surface water source through an outfall permit and 74:10:05:15, which approves construction of produced water handling facilities.

Figure 23 documents the geographic distribution of water quality samples across the Study Area and shows the distribution of sampled salinity, expressed as total dissolved solids, in those water samples. This information is from a U.S. Geological Survey (2008a) database of water quality samples. Water quality information is available for 126 samples and salinity ranges from 1,005 to 322,637 milligrams per liter. Water quality sample distribution is:

- less than 5,000 milligrams per liter – 45 samples,
- 5,000 to 9,999 milligrams per liter – 24 samples,
- 10,000 to 49,999 milligrams per liter – 51 samples, and
- Greater than 50,000 milligrams per liter – 6 samples.

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Produced water samples from the U.S. Geological Survey (2008a) data base are available for only three fields in the Study Area. Samples indicate water is at best brackish in these fields. Samples show that:

1. Of 33 samples recorded for Buffalo Field (Figure 5), only eight were in the 4,700 to 10,000 milligrams per liter range and each would be considered to be brackish water. Twenty-three samples ranged from 11,500 to 32,000 milligrams per liter and the final two samples exceeded 50,000 milligrams per liter.
2. Four of the five samples taken from Bull Creek Field (Figure 5) are in the 5,000 to 9,999 milligrams per liter range (brackish) and one exceeded 23,956 milligrams per liter.
3. Four of the six samples taken from Barker Dome Field (Figure) are in the 5,000 to 9,999 milligrams per liter range (brackish) and the others were 13,512 and 18,814 milligrams per liter.

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. Treated water and a brine solution are produced in this process. The treated water is then usually disposed of at the surface while the brine would then need to be disposed of in a pit or injected into the subsurface. In 1998, this type of produced water facility was determined to be successful in southwestern Wyoming (PTTC, 2002). It could probably be successfully used in the cold climate of the Study Area, in locations where production of poor quality water cannot be disposed of by other means.

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 Water Separation

At least some water is produced along with the hydrocarbons in most wells within the Study Area. It is most often stored, at least temporarily, in dug pits on the well site. Small amounts of water may be allowed to evaporate or percolate into the subsoil. Larger amounts may be trucked to bigger 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. Nearest use of this technology has been in southeastern Saskatchewan, Canada (Veil, et al. 1999).

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. Vapor recovery units are not common, but have been installed at some locations in New Mexico and Texas.

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. Risk-Based Corrective Action is a streamlined approach, defined by the ASTM, in which exposure and risk assessment practices are integrated with traditional components of the corrective action process to ensure that appropriate and cost-effective remedies are selected, and that limited resources are properly allocated. 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. West Short Pine Hills and Cady Creek are the largest gas producing fields in the Study Area. 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. Storage sites are most concentrated in consuming regions of the United States and near major pipelines. There are no underground gas storage sites within the Study Area.

ASSESSMENTS OF OIL AND GAS RESOURCES

The Energy Information Administration has recently provided forecasts of United States energy supply (Energy Information Administration, 2007a). Technically recoverable United States oil resources (as of January 1, 2005) were estimated to be 168.8 billion barrels. The technically recoverable natural gas resource was estimated to be 1,341 trillion cubic feet. The Rocky Mountains account for about 37 percent of the natural gas and 17 percent of the oil projections of the technically recoverable resource base on public lands in the lower 48 states (Humphries, 2004).

A number of recent assessments of technically recoverable (see Glossary) gas resources have been made for the Rocky Mountain region. Each estimate has been prepared using somewhat different assumptions. They all show a large natural gas resource for the Rocky Mountain region.

- The Energy Information Administration (2003) uses a natural gas resource base of 383 trillion cubic feet for the Rocky Mountain region.
- The Potential Gas Committee (2003) estimated 288 trillion cubic feet of natural gas, including 50 trillion cubic feet of proved reserves.
- As part of a study done in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003) the U.S. Geological Survey estimated the technically recoverable gas resource for five basins in the Rocky Mountain region at 226 trillion cubic feet. Of that total, they estimated a conventional gas resource of 13 trillion cubic feet, tight gas sand and shale gas resources of 127 trillion cubic feet, and 43 trillion cubic feet each of coalbed natural gas and proved reserves.
- The National Petroleum Council (2003) estimated 284 trillion cubic feet of natural gas for the Rocky Mountain region. The Council also presented a comparative analysis of their estimates with those of the Energy Information Administration, Potential Gas Committee and U.S. Geological Survey to better understand the factors that influenced the differences among each estimate.

The National Petroleum Council (2003) has divided remaining natural gas resources into proved reserves, growth reserves (or reserve growth), and undiscovered resources (see Glossary for descriptions of each). They further divided undiscovered resources into conventional and nonconventional (also known as unconventional) types (see Glossary for descriptions of each).

As of January 1, 2002, the National Petroleum Council (2003) estimated Rockies proved natural gas reserves to be 50 trillion cubic feet. The Energy Information Administration (2004) was able to separately assess proved tight sand gas reserves (26.8 trillion cubic feet) and proved coalbed natural gas reserves (14.8 trillion cubic feet) for the Rocky Mountain region. Growth to proved gas reserves in the Rockies was estimated at 26 trillion cubic feet (National Petroleum Council, 2003). Finally, undiscovered resources for conventional gas were estimated to be 173 trillion cubic feet, while nonconventional gas resources were estimated to be 209 trillion cubic feet (National Petroleum Council, 2003).

The U.S. Department of Energy (2003) has reported that “as geologic knowledge and technology for finding and producing natural gas have improved, the estimated volume of natural gas resources in the Rocky Mountain States has grown.” They assumed that as long as investment continued towards expanding the geologic knowledge base and technology progress, then there would be a continued upward trend in future resource assessment volumes and recovery would be expected to continue to increase, at least through 2015. These reserve additions will be needed in the future to replace those that are being depleted due to production and consumption.

Curtis and Montgomery (2002) reported that “the importance of natural gas as a primary energy source in the United States has grown considerably during the past decade.”

Rising demand in this country will result in a 1.1 percent average annual increase in our consumption of energy to 2030 (Energy Information Administration, 2007a). During that period natural gas consumption will rise from 21.08 trillion cubic feet in 2005 to 26.9 trillion cubic feet in 2030 (Energy Information Administration, 2007a). Our domestic production rose from 17.7 to 19.7 trillion cubic feet (11.3 percent increase) for the 1990 to 2000 period (Curtis and Montgomery, 2002), and then dropped to 18.3 trillion cubic feet in 2005. Production of gas is expected to rise to 20.6 trillion cubic feet in 2030 (Energy Information Administration, 2007a). North American producing areas are expected to provide 75 percent of long-term United States gas needs, but they will be unable to meet the entire projected demand (National Petroleum Council, 2003). The gap between consumption and production has necessitated a rise in imports and concern about our future United States energy supply.

Oil and gas produced within the Study Area to date, has helped supply a portion of United States demand. The Study Area will also continue 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 Study 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 2029.

We will present below the results of a number of oil and gas resource assessments as they relate to the Study Area. A discussion of oil-in-place and gas-in-place estimates will be followed by estimates available for proved oil and gas reserves. Finally, we will review recoverable resource estimates that have recently been made by groups such as the U.S. Geological Survey, the Department of Energy (contracted analysis), and the Potential Gas Committee. Each group uses slightly different methods and assumptions when making their predictions of potential resources. Although these estimates cannot be directly correlated, combined they provide an idea of the range of oil and gas resources that may be available for exploration and development in the Study Area through 2029.

OIL-IN-PLACE ESTIMATES

No recent estimates of oil-in-place (see Glossary definition for *in-place* resources) were available for the Study Area. Curry (1971) estimated 18.1 million barrels of discovered oil-in-place and 16.1 million barrels of remaining undiscovered oil-in-place existed in South Dakota, but Curry's estimate was made decades ago. Oil-in-place for Alum Creek Field has been reported to be 3.859 million barrels (Cardinal and Sherer, 1984).

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. 2002). Rakhit Petroleum Consulting LTD. (2007) has projected 4.5 trillion cubic feet of shallow gas-in place in undiscovered gas reserves in the Western Plains area, which includes the Study Area. No other gas-in-place estimates that cover the Study Area are known.

PROVED OIL AND GAS RESERVES

In 2006, total United States, lower 48, onshore proved reserves (see Glossary) of crude oil were 17.093 billion barrels, natural gas liquid reserves were estimated at 8.134 billion barrels, and dry natural gas reserves were 200.840 trillion cubic feet (Energy Information Administration, 2007a). The Energy Information Administration (2007a) does not report proved reserve estimates for the state of South Dakota, since it is a small portion of the total reserve for each hydrocarbon type. It did report a range of reserves for South Dakota as follows: 1 to 100 billion cubic feet of dry gas, and 10 to 100 million barrels of crude oil.

The U.S. Departments of Interior, Agriculture, and Energy (2008) estimated proved reserves in the Williston Basin of 769 million barrels of liquid and 841 billion cubic feet of gas. These estimates were made for 955 fields of which only 29 fields (3 percent) lie within northwestern South Dakota. They also estimated remaining reserve growth (see Glossary) from the 955 fields (29 fields within northwestern South Dakota) to be 1.641 billion barrels of liquids and 2.801 trillion cubic feet of gas.

The U.S. Departments of Interior, Agriculture, and Energy (2008) also estimated proved reserves in the Powder River Basin of 148 million barrels of liquid and 2.737 trillion cubic feet of gas. These estimates were made for 784 fields of which only 10 fields (1.3 percent) lie within southwestern South Dakota. They also estimated remaining reserve growth (see Glossary) from the 784 fields (10 fields within northwestern South Dakota) to be 170 million barrels of liquids and 839 billion cubic feet of gas.

The National Petroleum Council (2003) estimated that the Rockies had a remaining proved gas reserve of 49.7 trillion cubic feet, with 67.1 trillion cubic feet produced to that time. For the Williston/Northern Great Plains region they estimated 4.5 trillion cubic feet of cumulative gas production and 1.3 trillion cubic feet of proven gas reserves, with an ultimate recovery for the region of 5.8 trillion cubic feet. There are no known recent attempts to estimate proved oil and gas reserves for the Study Area.

U.S. GEOLOGICAL SURVEY RESOURCE ASSESSMENTS

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. 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. Three of those assessed provinces are the Denver Basin, Williston Basin, and Sioux Arch provinces. Each province lies partly within the Study Area.

As part of a study prepared in compliance with the Energy Policy and Conservation Act Amendments of 2000 (U.S. Departments of Interior, Agriculture, and Energy, 2003, 2006, and 2008) the U.S. Geological Survey prioritized oil and gas assessment studies for certain basins. An updated analysis covering the Denver Basin Province, partly lying in the Study Area (U.S. Geological Survey, 2003 and 2007) was prepared in response to their new priorities. In these two reports the U.S. Geological Survey updated their quantitative estimate of the undiscovered oil and gas resources for this province. An updated analysis covering the Williston Basin Province was also recently published (U.S. Geological Survey, 2008b and 2008c). A more complete discussion of the new assessments (Denver and Williston basin provinces) and the earlier 1995 U.S. Geological Survey assessment for the Sioux Arch province, province locations, and estimates of the oil and gas resource volumes is presented in Appendix 1.

For the Denver Basin and Williston Basin province assessments, the U.S. Geological Survey estimated undiscovered technically recoverable resources (see Glossary definition) for each play or assessment unit (Tables A1-2 and A1-3). When preparing estimates of resource quantities for each province, 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. For each province assessment they used a future time frame—forecast span—of 30 years when estimating quantities of the potential oil and gas resource. The U.S. Geological Survey did not prepare an estimate of the undiscovered technically recoverable resources for the single hypothetical play of the Sioux Arch Province.

For each type of hydrocarbon, a mean estimated undiscovered resource volume was recorded for each province assessment unit and a calculation of the portion lying within the Study Area was made (Tables A1-2 and A1-3). We estimate that all portions of assessment units lying within the Study Area contain a mean undiscovered volume of **14.18 million barrels of oil, 351.42 billion cubic feet of gas, and 2.1 million barrels of natural gas liquids**.

In addition, we estimate that the Study Area's oil resource could **range from 4.43 to 28.2 million barrels, the gas resource could range from 92.53 to 762.16 billion cubic feet, and the natural gas liquids resource could range from 0.58 to 4.27 million barrels** (assuming fractile data used has a perfect positive correlation)**.**

Dyman, et al. (1997) show the Williston Basin Province (Figure 6) contains sedimentary rocks at depths greater than 15,000 feet. They also show that those rocks only appear to occur at those depths in the North Dakota portion of the province. They do not report the presence of sedimentary rocks at depths greater than 15,000 feet anywhere within the Study Area.

DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS

The U.S. Departments of Interior, Agriculture, and Energy (2003, 2006, and 2008) have respectively contributed to three publications that inventoried oil and gas resources in parts of the Rocky Mountains, including parts of the Study Area. Potential Denver Basin Province (which includes the southwestern most part of the Study Area) oil and gas resources were analyzed for the 2006 publication. Potential Williston Basin Province (which includes the northern two-thirds of the Study Area) resources were analyzed for the 2008 publication. Only Bakken related In addition, their 2008 publication included extrapolated analysis of a portions of the Williston Basin Province that they had not updated with more detailed analysis. No potential resource values for the Sioux Arch Province were assigned under any of the three publications. In addition, the reports discussed restrictions to development of oil and gas resources in these areas.

The Energy Information Administration (2007b) projected a crude oil technically recoverable resource for the Rocky Mountains of 19.92 billion barrels. They also projected natural gas technically recoverable resources for the Rocky Mountains of 249.41 trillion cubic feet. The projected natural gas resource was further subdivided into several categories which are:

- Undiscovered nonassociated conventional gas – 14.68 trillion cubic feet
- Inferred reserves of nonassociated conventional gas – 15.74 trillion cubic feet
- Unconventional tight gas – 149.47 trillion cubic feet
- Unconventional shale gas - 14.11 trillion cubic feet
- Unconventional coalbed natural gas – 55.41 trillion cubic feet.

POTENTIAL GAS COMMITTEE ASSESSMENT

The Potential Gas Committee is a group of volunteer members from the oil and gas industry, government agencies, and academic institutions. Its objective is to provide periodic estimates, using expert knowledge, “of the potential supply of natural gas that may become available to the nation in addition to currently available proved recoverable reserves of natural gas” (Potential Gas Committee, 2003). The Committee 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. The Potential Gas Committee (2003) made a most likely estimate for each of these three categories and a most likely total resource volume. We will refer to the most likely estimate of undiscovered technically recoverable and marketable volumes of the gas resource in our following discussion.

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 separate estimates for gas resources below a depth of 15,000 feet and for coalbed natural gas resources.

The Potential Gas Committee (2003) estimated the most likely quantity of gas resource (includes all the undiscovered gas resource plus that part of the discovered resource that is not included in proved reserves) for two regions that at least partly lie within the Study Area. The Williston Basin area lies in northwest South Dakota, northeast Montana, and western North Dakota. For the Williston Basin area they estimated that the most likely resources are 1.722 trillion cubic feet of gas from 0 to a depth of 15,000 feet, and 98 billion cubic feet of gas for depths greater than 15,000 feet. We estimate that less than 20 percent of the shallower resources are present within the Study Area. None of the deeper resources are likely to be found in the Study Area since no sedimentary section is apparently present at depths below 15,000 feet.

The Denver Basin, Chadron Arch, and the Las Animas Arch area contains an estimated most-likely resources of 2.437 trillion cubic feet of gas from 0 to a depth of 15,000 feet and no gas for depths below 15,000 feet. We estimate that less than 5 percent of the shallower resources could be present within the Study Area.

Most likely estimates of coalbed natural gas resources (includes all the undiscovered gas resource plus that part of the discovered resource that is not included in proved reserves) were also made for the Fort Union Coal Region in the Williston Basin and the Denver Basin Coal Region (Potential Gas Committee, 2003). The Committee's Fort Union Coal Region includes the Fort Union Coal Region of Figure 16, and includes lands in northwestern South Dakota, northeast Montana, and western North Dakota. Their estimate of most likely coalbed natural gas resources for the entire region is 500 billion cubic feet. The portion of this region within the Study Area is less than 10 percent of the total Fort Union Coal Region.

NATIONAL PETROLEUM COUNCIL ASSESSMENT

The National Petroleum Council (2003) projected an undiscovered gas resource of 11.1 trillion cubic feet of gas for an area defined as the Williston/Northern Great Plains region. They compared the region to an equivalent area studied in the U.S. Geological Survey's 1995 assessment discussed above. The National Petroleum Council projection was about one quarter of the older U.S. Geological Survey's assessment of 45.8 trillion cubic feet of undiscovered gas resources. Their reduction from the U.S. Geological Survey's estimate was based on relatively unsuccessful exploratory drilling during the previous decade, which significantly reduced the area of potential production.

RAND SCIENCE AND TECHNOLOGY ASSESSMENT

The William and Flora Hewlett Foundation funded an assessment of natural gas and oil resources of the Greater Green River Basin, in Wyoming by RAND Science and Technology, a research unit of RAND. A number of reports were published as a result of the RAND Science and Technology study (LaTourrette, et al. 2002a; LaTourrette, et al. 2002b; LaTourrette, et al., 2003; and Vidas, et al. 2003). The LaTourrette, et al. (2002a and 2002b) reports were prepared to:

- review existing resource assessment methodologies and results,
- evaluate recent studies of federal land access restrictions in the Intermountain West,
- consider a set of criteria that can be used to define the “viable” hydrocarbon resource, with particular attention to issues relevant to the Intermountain West,
- develop a more comprehensive assessment methodology for the viable resource, and
- employ this methodology to assess the viable resource in Intermountain West basins.

The report by LaTourrette et al (2003) indicated that the details of their spatial analysis and other data were available on request. We contacted the lead author and asked for this information in order to see the details of how the methodology was applied. Unfortunately, that information had been lost and was no longer available. This type of analysis has not been used to analyze any other regions within the Rocky Mountain region.

BIOGENIC AND SHALLOW GAS

Upper Cretaceous shales underlying the Study Area represent effective source rocks for biogenic gas generation. Twenty percent of the world’s discovered natural gas reserves are of biogenic origin (Rice and Claypool, 1981). Biogenic gas is generated by anaerobic bacteria through the decomposition of organic matter in sediments. This can occur at temperatures between 0 and 65 degrees Celsius (32 and 150 degrees Fahrenheit), and such gas accumulations are known to accumulate in large quantities (Shurr, 2001). This gas is generated in thermally immature sediments and can accumulate in large quantities. Generally, the terms "shallow gas" and "biogenic gas" are used interchangeably; however, some occurrences of shallow gas are not known to be of biogenic origin. In general, the gas occurs at shallow depths (less than 2,000 feet), are underpressured, and are dominantly made up of methane gas (Shurr, 2001).

Chimney, et al. (1992) reported that shallow biogenic gas is produced from Upper Cretaceous rocks along the Cedar Creek anticline and on the north-plunge of the Black Hills Uplift. Shurr and Ridgley (2002) reported that West Short Pine field (Figure 5) contains biogenic gas. In this area, clastic (see Glossary) Cretaceous rocks are thought to be both source beds and reservoirs, and the gas is of an early generation biogenic origin (GeoShurr, 2008). Basin-margin shallow gas accumulations within the northwest part of the Study Area are located at West Short Pine Hills and Cady Creek fields (Figure 5) in the Shannon Sandstone (Shurr, 2001). Both fields are located on anticlinal structures. In recent years, shallow tests at West Short Pine Hills Field have recovered gas shows, but no commercial production (GeoShurr, 2008).

Another shallow gas location is at the abandoned Pierre Gas Field near the town of Pierre, South Dakota, and in the Dakota Sandstone (Shurr, 2001). A surrounding area of several thousand square miles has historic shows of shallow gas (GeoShurr, 2008). Steece and McGillivray (2005) reported on the Pierre Gas Field. They reported that a gas plant was installed at Pierre, South Dakota in 1889, and there are records of methane gas production from 1899 through 1948. Exploration in the area during the 1970s targeting the Niobrara Formation and Dakota Sandstone recorded a few gas shows (GeoShurr, 2008).

An additional shallow gas accumulation is reported near the town of Ardmore, South Dakota, in Fall River County (southwestern part of the Study Area) and in the Newcastle Sandstone (Shurr, 2001).

Shurr, et al. (2006) have identified ultra-shallow microbial methane on the eastern margin of the Williston Basin and in southeastern South Dakota as an untested unconventional gas play. They have identified the Cretaceous Niobrara Formation as having potential for generation of microbial methane at ultra-shallow depths (less than 2,000 feet).

The U.S. Geological Survey (2003 and 2007) has prepared estimates of undiscovered technically recoverable biogenic gas resources for their Denver Basin Province assessment (see Appendix 1). Their Upper Cretaceous Niobrara Biogenic Gas total petroleum system, Niobrara Chalk assessment unit could contain as much as 186.67 billion cubic feet of gas within the Study Area (Table A1-2).

Shurr and Ridgley (2002) indicated that "… reserves of shallow biogenic gas are ideally suited for exploration and development by small, independent operators. Drilling and completion costs are relatively low for these shallow accumulations, and lease costs also are low. Many accumulations are located in areas that are underdeveloped. Consequently, leases are relatively easy to acquire. Furthermore, formerly stranded sweet spots will come online as the domestic infrastructure expands to meet increased demands and attendant higher prices." Hester (2006) has reported that although the potential for production from these reservoirs exists, there are reasons for a lack of commercial development of these resources:

- the lack of pipeline infrastructure (gas pipeline and gathering systems) in the area,
- the lack of predictable and reliable rates of production due to the geologic nature of these continuous-type gas accumulations, and
- the difficulty in recognizing and selecting potentially productive gas-charged reservoirs.

The industry will need to overcome these obstacles in order to develop these resources.

RESERVATION LANDS

The known publicly available assessments of potential for occurrence of oil and gas resources are:

- two reports prepared for the Standing Rock Indian Reservation (Rice and Bretz, 1978, and Bureau of Indian Affairs, 1997), which lies on the South Dakota/North Dakota border,
- a report on the Lower Brule Indian Reservation (Cox and Beach, 1980), which straddles the eastern boundary of the Study Area,

- a report on the Cheyenne River Indian Reservation (Bretz, et al. 1976), in Ziebach and Dewey counties, and
- a report on the Pine Ridge Indian Reservation (Raymond, et al. 1976), in Shannon and Jackson counties.

The Bureau of Indian Affairs (1997) reports undiscovered resources for Province-wide plays that cover the Standing Rock Indian Reservation, but does not attempt to estimate the number of undiscovered fields or proportions of these resources that may lie within the Reservation. All other reports only discuss the potential for the occurrence of oil and/or gas that may occur under Reservation lands and do not attempt to project quantities of oil and/or gas that may occur.

OIL AND GAS OCCURRENCE POTENTIAL

The Bureau has established criteria to use in rating the oil and gas occurrence potential of lands studied for planning documents such as the Resource Management Plan to be prepared for the Study Area. This rating is based on guidance outlined in Bureau of Land Management Handbook H-1624-1 which states:

"Due to the nearly ubiquitous presence of hydrocarbons in sedimentary rock... the following [is used] for classifying oil and gas [occurrence] potential:

- HIGH: Inclusion in an oil and gas play as defined by the [United States Geological Survey] national assessment, or, in the absence of play designation by the [United States Geological Survey], the demonstrated existence of: source rock, thermal maturation, <u>and</u> reservoir strata possessing permeability and/or porosity, and traps. Demonstrated existence is defined by physical evidence or documentation in the literature.
- MEDIUM: Geophysical or geological indications that the following may be present: source rock, thermal maturation, and reservoir strata possessing permeability and/or porosity, and traps. Geologic indication is defined by geological inference based on indirect evidence.
- LOW: Specific indications that one or more of the following may not be present: source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps.
- NONE: Demonstrated absence of (1) source rock, (2) thermal maturation, or (3) reservoir rock that precludes the occurrence of oil and/or gas. Demonstrated absence is defined by physical evidence or documentation in the literature."

Using the above criteria, we consider that Study Area lands have high, moderate, or low potential for the occurrence of oil and gas (including coalbed natural gas, but excluding shallow biogenic gas) as shown in Figure 24. All but one (see below) of the oil and gas play areas and assessment units within the Williston Basin, Denver Basin, and Sioux Arch provinces, as defined by the U.S. Geological Survey (Beeman et al., 1996: Charpentier et al., 1996: Gautier et al., 1996 and U.S. Geological Survey, 2003, 2007, 2008b and 2008c), are considered as being in areas of high occurrence potential for oil and gas. Additionally, the area of the Williston Basin Fort Union Coalbed Gas assessment unit (U.S. Geological Survey, 2008c and 2009) is considered to have a high occurrence potential. Approximately 52 percent of the Study Area falls within the high occurrence potential category.

Areas of moderate occurrence potential are those where no U.S. Geological Survey plays or assessment units or only hypothetical plays have been mapped, but have shown historically to have limited oil and/or natural gas production or tests with shows of oil and/or natural gas (there are geologic indications that source rock, thermal maturation, and reservoir strata possessing permeability and/or porosity, and traps may be present). Approximately 42 percent of the Study Area falls within the moderate category.

The remaining 6 percent of the Study Area are lands that fall outside of play areas or assessment units designated by the U.S. Geological Survey, and have shown no historical oil or gas production. These areas are located in the Black Hills which are made up of Precambrian igneous and metamorphic rocks where traps, reservoir strata, and hydrocarbons are not known to occur. It should be noted, however, that the southern portion of the Black Hills Precambrian rocks which occur in Custer and Fall River counties are included in the U.S. Geological Survey's Denver Basin Lower Cretaceous and Permian-Pennsylvanian total petroleum system assessment units. We consider this portion of the Black Hills to have low potential for occurrence because the Lower Cretaceous and Permian-Pennsylvanian rock units assessed are absent. These areas are designated as low occurrence potential since one or more specific indicators of the presence of hydrocarbons do not appear to be present.

Using the above criteria, we consider all lands within the Study Area to have high occurrence potential for shallow biogenic gas. The U.S. Geological Survey (2008b and 2009) has identified two shallow biogenic gas assessment units that cover the majority of the Study Area. The first of these is the "Upper Cretaceous Niobrara Biogenic Gas" identified in the Denver Basin Province. This play includes approximately one third of the Study Area lands, primarily in the south and east. The second assessment unit is the "Shallow Biogenic Gas" identified in the Williston Basin Province, and includes all lands in the Study Area north of the White River and the northern borders of Custer and Shannon Counties. Combined, these two plays cover all Study Area lands with the exception of Custer and Fall River counties, and the western portion of Shannon County. The more recent Williston Basin assessment studied all potential shallow biogenic gas resources, while the Denver Basin assessment focused on only shallow biogenic gas associated with the Niobrara Chalk as a source rock. We believe that if the older Denver Basin assessment had included all potential shallow biogenic gas sources, these counties would ultimately be shown to have similar potential to those of the Williston Basin area, since the geologic conditions that could produce biogenic gas do not differ significantly from the lands to the north and east.

PROJECTIONS OF FUTURE ACTIVITY 2010-2029

The Energy Information Administration (2005) estimates that over the next two decades:

- U.S. energy demand will grow at an average annual rate of 1.4 percent
- energy efficiency of the economy will increase at an average annual rate of 1.5 percent
- future natural gas supply growth will depend on nonconventional domestic production, natural gas from Alaska, and liquefied natural gas imports
- U.S. oil imports will grow from 56 percent to 68 percent
- price of oil and natural gas will be higher than in the past
- carbon dioxide emissions will grow at an average annual rate of 1.5 percent.

The above projected increases in demand and in oil and gas prices indicate continued industry emphasis on increasing oil supplies and searching for additional natural gas supplies in the Study Area. Much of the Study Area oil and gas supply growth is expected to come from production from reservoirs like those in the Harding, Fall River, and Custer Counties.

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 Study Area. Boswell (2006) reported that "in today's market the average unconventional resource play breaks even at $4 per thousand cubic feet of gas and requires in excess of $7 per thousand cubic feet to achieve 20 percent rate of return at the wellhead." The National Petroleum Council (2003) has projected that through 2025 "supply and demand will balance at higher price ranges than historical levels" in the United States.

Gas Prices

Data for Figure 25 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2008a). Wellhead price data was not available for the calendar years 1994 to 1996. The Energy Information Administration price projection data is an average for Lower 48 Wellhead Prices and is made in 2007 dollars. Historical prices are in nominal dollars. The trend in historical wellhead prices clearly show the recent (1999 and later) volatility that has occurred in natural gas prices in North Dakota. Prior to 1999, wellhead natural gas prices were relatively stable. The drop of nearly 30 percent from 1985 to 1986 represents only a modest fluctuation when viewed in context with the nearly 650 percent increase from 1986 to 2005 prices and the future price predictions outlined below.

Sieminski (2007) predicts that U.S. natural gas prices will average 7 dollars per thousand cubic feet for the next five years. Petak (2007) projected that Henry Hub (near the town of Erath in southern Louisiana) prices will average between 6 and 8 dollars per thousand cubic feet in the long-term (to 2025).

The Energy Information Administration (2008a) projects that natural gas prices will fall sharply in 2009 from the recent spike in prices which began in 2003 and likely culminated in 2008. Prices are then expected to begin a gradual and linear rise from

$5.73 per thousand cubic feet (2007 dollars) in 2009 to $8.39 per thousand cubic feet in 2030 (Energy Information Administration , 2008a). They also predict that the current high natural gas prices will stimulate development of new gas supplies and constrain growth in natural gas consumption (Energy Information Administration, 2008b). The combination of a growing demand and limited supply has created market tightening and led to higher gas prices and price volatility (National Petroleum Council, 2003). However, the Energy Information Administration projects that in the long-term, growth in domestic production will outpace growth in domestic demand leading to a decline in net imports. Most of this growth is expected to come from nonconventional sources, in particular from gas shale production.

The National Petroleum Council anticipates that price ranges will be determined by response to "increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and nonconventional supplies from North American… and increasing access to world resources through LNG imports (National Petroleum Council, 2003). It is not known if liquefied natural gas imports will meet expectations nor if new pipelines will connect gas supplies in northern Canada and Alaska with U.S. markets. While both scenarios would not happen for years, they could decrease future gas prices. Consequently, the projection of future natural gas prices should be considered speculative.

It is important to note that natural gas exploration historically has been minimal in the Study Area, though in the past several years, interest has increased. This is likely due to the spike in natural gas prices, and the relatively unexplored nature of the Study Area lands with respect to natural gas. The recent activity has thus far focused on shallow gas exploration of the Shannon member in Harding County, Cretaceous Dakota and Niobrara gas tests in Stanley and Hughes counties (Fidelity Exploration), as well as several, "sub-glacial/Cretaceous Niobrara" shallow gas tests in Spink County (BioRock Gas). All of the tests in Spink County were unsuccessful dry holes; however, Spyglass Exploration recently announced a new Shannon member shallow gas field discovery in the Harding County (McGillivray, 2008b). This will likely spark further interest in the area for natural gas exploration.

These natural gas price projections allow some generalizations concerning future gas drilling and production activity in the Study Area. If the Energy Information Administration gas price scenario is accurate, the recent peak in interest in natural gas exploration in the Study Area will likely continue, even though prices are expected to drop sharply from their 2008 high. Prices are expected to only fall, on average in 2009, to 2006 levels; the 2006 prices were more than double the average Wyoming wellhead acquisition price from the previous ten year period. At no time are prices projected to drop below 2004 levels. Furthermore, it is likely that gas production will continue to be mainly a function of the ability of industry to discover and economically develop gas accumulations, and their ability to increase drilling, production, processing, and transportation efficiency.

According to the Energy Information Administration's (2008b) 2008 Annual Energy Outlook, United States demand for natural gas in 2007 was 22.9 trillion cubic feet. United States demand is expected to peak in 2016 at 23.83 trillion cubic feet (an increase of 3.9 percent). Demand is expected to continually increase through 2030. Future natural gas production increases, to accommodate increased demand, are projected to come partly from the Rocky Mountain area. Anticipated new production in the Study Area is expected to come mainly from the addition of incremental production from existing natural gas fields, and the discovery of new shallow biogenic gas and other unconventional types of reservoirs such as shale gas.

Oil Prices

Sieminski (2007) recently reported that West Texas Intermediate oil prices averaged 19.7 dollars per barrel in the 1990s. In documentation submitted in support of his testimony before the U.S. House of Representatives Select Committee on Energy Independence and Global Warming, Sieminski (2008) stated that "our [Deutsche Bank] forecast for next year is that oil prices should average about $105/barrel," and that "for the longer term... prices will settle toward the cost of marginal supply, or $85/barrel..." While recent world events have seen oil prices fall from a high of over $146 per barrel (NYMEX light sweet crude futures price) in July, 2008 to less than $65 per barrel in November, 2008, it is likely that Sieminski's averages will approximate actual trends. Indeed, even with the volatility seen in prices throughout 2008, through the first week of November, 2008, the average price for light sweet crude in 2008 has been approximately $108 per barrel (Energy Information Administration, 2008c).

Data for Figure 26 (historical and projected crude oil prices) were obtained from the Energy Information Administration. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in South Dakota. The Energy Information Administration projection is an average imported Low Sulfur Light Crude Oil Price and is made in 2007 dollars.

The Energy Information Administration (2008a) predicts that world oil price will be higher for 2006-2030 than presented previously. Domestic petroleum-based liquids consumption is expected to remain flat through 2030 (approximately 20 million barrels per day) due to increased use of and reliance on biofuels. However, worldwide demand will continually increase during the same time, driving world oil prices to higher levels. The Energy Information Administration reference case projects that world oil prices will sharply decline from current levels to about $60 per barrel in 2009, and start rising again as production in non-OPEC regions peaks, and continue rising to $130 per barrel in 2030 (all prices in 2007 dollars). However, as stated in their 2008 projections, “recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections” (Energy Information Administration 2008b). Such uncertainty is demonstrated in their low- and high-price case projections. These cases reflect a wide band of potential world oil price paths, ranging from $40-50 per barrel in the low case to over $180 per barrel in the high case in 2020 (Energy Information Administration, 2008a).

If the Energy Information Administration crude oil price projection is accurate, future oil drilling and production will likely continue at levels similar to those seen since 2004 and remain at this level until the horizontal re-development of the Red River oil fields in Harding County is completely realized. Further drilling activity will likely continue at low levels as operators explore the fringes of these fields. Barring any significant new discoveries, however, it is unlikely that drilling activity will increase significantly beyond the peak seen in 2005.

LEASING

After initial fieldwork, 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. Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A 140 dollar fixed-cost recovery fee per parcel is charged and the successful bidder must meet citizenship and legal requirements. In addition to the lease bonus, a 1.50 dollar per acre rental is charged for the first five years and two dollar per acre thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on production is required. Leases that 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.

For South Dakota, periodic federal oil and gas lease sales are held in Billings, Montana. Since August 1996, only lands nominated by industry have been 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 that protect potentially affected, mainly surface, resource values.

Oil and gas prices and exploration success will, to a great extent, determine the amount of acreage leased and bonus bids received. Forty-nine percent of the money earned from oil and gas leases on public domain minerals goes to the State of South Dakota. The rest stays with the federal treasury, where it is split between the conservation fund and the general fund on a 4:1 ratio respectively.

Figure 27 presents the locations of leased and unleased Federal oil and gas minerals within the Study Area. There were about 119,879 acres of leased Federal oil and gas minerals in December of 2007 and more than 1.35 million unleased acres. Only about eight percent of Federal oil and gas minerals were leased at that time.

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 are not permitted with the Bureau even though the surveys cover federal minerals. Two-dimensional seismic surveys have successfully been used for years in the Study Area to explore for gas traps. Figure 28 shows areas of relative density of existing known seismic lines by county. The highest concentration of two-dimensional seismic lines is in Harding County, with almost all lying northeast of a line running from the northwest corner of the county to the southeast corner. In Perkins County, surveys have been concentrated in the north half and in Corson County they have been concentrated in the western two-thirds. In Fall River County, surveys have been run in the southwest and eastern portion.

In the counties with moderated densities (Figure 28), two-dimensional seismic surveys have been rarer and tend to be concentrated in only one area of the county. In Butte County they are concentrated in the southeast corner; in Ziebach County they are concentrated in the north; and in Dewey County they lie in the north-central area. In the remaining three counties with a low seismic density, only one or two isolated seismic lines have been acquired. There are a number of counties in the Study Area where no seismic activity is reported. The only known three-dimensional seismic program was recently run on the border with North Dakota and covered only about four sections of land within South Dakota (within Harding County).

Occasional seismic surveys will continue to be run in the Study Area and will generally be in or near areas and counties were past activities have occurred. Seismic surveys will be less frequent in eastern parts of the Study Area. We anticipate that the number of seismic surveys in the Study Area will decrease with time.

PROJECTIONS OF FUTURE DRILLING ACTIVITY

It is difficult to predict what will occur a few years into the future, but it is even more difficult to predict 20 years ahead. In an attempt to gain more insight as to what may occur in the Study Area, the authors approached geologists and engineers in the oil and gas industry for their input. Major oil and gas companies operating in the Study Area were contacted by letter and asked what development activity they anticipated during the next 20 years. The Bureau also contacted many of these companies by telephone, either a few days after the letters were sent, or in order to clarify information after replies were received. This data was compiled and used to help project locations and amounts of future drilling activity within the Study Area. A review of available technical data was also made to help make these projections.

Projected Oil and Gas Drilling Activity

For a base-line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2002, page 13), we estimate that during the 20-year planning cycle of 2010 to 2029, as many as 524 wells will be drilled in the Study Area. Up to 75 of these wells could be coalbed natural gas wells (to be discussed later). Of the 449 remaining wells, 359 wells are projected in and around established fields in the southern Williston Basin (Harding and Butte counties); 40 in and around established fields in Fall River County in the eastern Powder River Basin; and 50 scattered across the remainder of the Study Area.

We estimate that 94 of the 449 drilled oil and gas wells will be located on Bureau managed oil and gas minerals. As many as four of the 75 coalbed natural gas wells, could be located on Bureau managed oil and gas minerals.

The estimated development potential and related drilling density (per township) of the projected 449 oil and gas wells is shown on Figure 29. Estimated acres, number of townships, projected average drilling densities, and percentage of the Study Area within each development potential classification type shown in Figure 29 are summarized in Table 4. Much of the anticipated drilling activity will be concentrated in areas of high and moderate development potential, which account for only 3.1 percent of the area in which development potential was assessed.

Development potential is defined as high, moderate, low, very low, and none. High development potential indicates areas where we estimate **average** drilling density will be 10 to 29 well locations per township (one township is about 36 square miles) during 2010-2029. Moderate potential indicates 2 to 10 wells per township; low potential indicates 1 to 2 well locations per township; and very low is defined as less than one well location per township. A very high category (more than 30 wells per township) was presented to the oil and gas companies approached for input, but none of these companies indicated they anticipated such development to occur. Based on lack of company input and historical drilling trends, no areas of very high potential were assigned within the Study Area. Badlands National Park, Wind Caves National Park, Mount Rushmore National Monument, and Jewel Cave National Monument were not assessed any potential for future development.

Many of the townships marked as high development potential already are relatively densely drilled. Many new wells in these townships will likely be drilled as infill or fringe wells, or as re-entries into existing boreholes. Wells within townships marked with moderate potential will likely be drilled as fringe wells in existing fields or wildcat wells looking to discover entirely new fields. With additional wells projected, density of wells in these areas will generally average one well per 160 acres by 2029. A few of these townships, those containing the oil and gas "sweet spots" will likely be more closely spaced.

In areas marked as low development potential, very few new wells will be drilled. Well densities will remain similar to what they are at present, with isolated townships having a small potential for an increase in drilling density, most likely around the fringes of townships marked with moderate potential. In areas marked as very low development potential, anticipated activity will be tied to exploration for new biogenic gas field discoveries, and most of these townships will not receive any drilling at all. If a new field discovery is made in any of these areas of very low development potential, subsequent drilling density could increase moderately. However, predicting a well density for such areas is not possible at this time due to the limited understanding of the Study Area's potential for biogenic gas accumulations. Based on previous biogenic gas exploration efforts in the Study Area, the probability of successful discovery of one or more new biogenic gas fields in these areas of very low development potential is likely to be low to very low. Similarly, the probability of the successful discovery of new oil or conventional gas fields in these areas is also considered to be very low.

There are several townships in Dewey, Stanley, and Hughes County marked as low potential. These townships each have one issued but undrilled drilling permit and as such exceed the very low potential category. Based on historical data and reasonable geologic expectations of these areas, it is not felt that ranking these townships above the low potential is warranted.

The only areas marked as no development potential (none) are lands where the igneous complexes of the Black Hills are found at or near the surface and petroleum resources are not expected to have accumulated.

We anticipate that future average well depths will remain in the present range (see Figure 19) with some minor increases in depth if deeper reservoirs are locally encountered. Deep wells, greater than 15,000 feet deep, are not anticipated. A few wells greater than 10,000 feet deep could be drilled to the Red River Formation, in Harding County, or deeper formations if such pools are discovered.

Drilling success rates will remain similar to those of the past 20 years, so about 60 percent of all wells drilled will be successful (oil, gas, or injection wells). Success rates will vary by area, with infill wells being more successful (90 percent or greater) and wildcat wells being only about 30 percent successful.

The majority of the anticipated activity will be additional drilling to grow identified reserves. Initial estimates of the size of new oil or gas fields are usually too low and over time, newer estimates of the size and ultimate recovery contribute to reserve growth (Central Region Energy Resources Team, 1996). Factors that contribute to reserve growth include:

- Physical expansion of fields by areal extensions and development of new producing intervals,
- Improved recovery resulting from application of new technology and engineering methods, and

- Upward revisions of reserve calculations based on production experience and changing relations between price and cost.

Projected Coalbed Natural Gas Drilling

The U.S. Geological Survey Coal Map of North America (U.S. Geological Survey, 2001a and 2001b) identifies an area underlain by Cretaceous and Tertiary coalbeds in the Williston Basin, which includes a portion of the Study Area (Figure 16). Some testing of lignite coals has occurred in North Dakota. Presently, there is no coalbed natural gas production in the Study Area, nor are there any exploration activities. Only recently has the U.S. Geological Survey (2008a and 2008b) published an updated assessment of the Williston Basin province, which included an assessment of Fort Union coalbed natural gas (see Appendix 1).

The strata in which the coals occur in the Study Area generally lie at depths too deep to be mined economically with today's technology, and hence are potential candidates for coalbed natural gas exploration. The majority of the coals in the Study Area lie within what is known as the Fort Union coal region. The Fort Union coals are actually Tertiary-aged lignites. None of the coals in the area are especially thick (generally less than 10 feet); however, the Potential Gas Committee (2003) estimated 0.5 trillion cubic feet of potential recoverable coalbed natural gas resources in the Fort Union coal region. As much as 10 percent of the gas in these strata may lie within the Study Area, based on surface acreage calculations. The U.S. Geological Survey's more recent analysis (2008b and 2008c) of the Fort Union Coalbed Gas assessment unit projected a mean of 882 billion cubic feet of natural gas in the Williston Basin Province. As much as 29.91 billion cubic feet could lie within the Study Area (see Figure A1-3 of Appendix 1). Additional coals (Black Hills coal region) are also known to occur in two localized areas within Fall River County; however, each area is only a few sections in aerial extent.

As stated earlier, approximately 75 new coalbed natural gas wells are projected to be drilled between 2010 and 2029. The estimated development potential of these new wells is shown on Figure 30. Only areas of low potential and no potential were outlined. Areas within the Fort Union Coalbed Gas assessment unit (U.S. Geological Survey, 2008b and 2008c) and the two above mentioned areas in Fall River County were assigned low potential. The area of the Fort Union Coalbed Gas assessment unit has the greater likelihood for the drilling of coalbed natural gas wells, while drilling in the small areas in Fall River County is very unlikely. The rest of the assessed Study Area was assigned no development potential for the planning period.

Since no drilling has yet occurred within the Study Area to explore for coalbed natural gas, we consider this play as being only hypothetical at present. No proposed coalbed natural gas activities have been proposed by industry in the Study Area and operators did not submit projections of future activity or interest in future activity.

In order to assess potential impacts of some exploration and potential development of the coalbed natural gas resource in the Study Area we are assuming that up to 75 new wells could be drilled. Results from coalbed natural gas pilot drilling projects in Wyoming suggest that often too few wells have been drilled to adequately evaluate the economic viability of a particular 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 adequately reduce pressure over a sufficient area and allow gas production. Also, heterogeneity in the coal may preclude the one interior well in a normal five or nine well pilot from providing the data necessary to adequately evaluate economic viability. We assume that any coalbed natural gas pilots in the Study Area will contain 16 to 25 wells. This should provide a better chance of obtaining adequate data and thus avoiding duplicate projects.

A projection of 75 new coalbed natural gas wells will allow some exploration activity and preliminary development if a newly discovered play is determined to be economic to produce. Any exploration will most likely occur in the final 10 years of the analysis period. Although the potential map (Figure 30) shows an equal potential distribution throughout the Fort Union coal region, much of the potential coalbed natural gas drilling is likely to only occur in one or two townships, not spread evenly over the area of potential.

PRODUCTION

Natural gas production from the Rocky Mountains has grown steadily since 1992 (National Petroleum Council, 2003). The Rockies are currently the largest producing region in the onshore lower 48 states. Much of this growth has been from nonconventional resources, although conventional production has also been increasing.

When the Energy Information Administration (2004) looked at past U.S. gas production they found that "Just a few years ago, it was believed that natural gas supplies would increase relatively easily in response to an increase in wellhead prices because of the large domestic natural gas resource base. This perception has changed over the past few years. While average natural gas wellhead prices since 2002 have generally been higher than during the 1990's and have led to significant increases in drilling, the higher prices have not resulted in a significant increase in production. With increasing rates of production decline, producers are drilling more and more wells just to maintain current levels of production. A significant increase in conventional natural gas production is no longer expected. Drilling deeper wells in conventional reservoirs is expected to slow the overall decline." More recent analysis has confirmed this trend. Foss (2007) found that gas production in the U.S. has been lower than the recent high of 20.5 trillion cubic feet reported in 2001. This decline in total production for the U.S. has occurred even while drilling has reached an all-time high. Foss (2007) indicated that "with a maturing resource base and unconventional plays increasingly the target of drilling, the production of new wells does not match historical results, nor is it expected to." In general, we expect that new gas wells drilled within the Study Area will follow this trend of reduced per well production from new wells completed.

Onshore oil production in the lower 48 states has been declining since the late 1980s and that decline is expected to continue into the future (Energy Information Administration (2006). New oil reservoir discoveries are likely to be smaller, more remote, and increasingly costly to exploit. In the Study Area, recent horizontal drilling emphasis in Harding County has resulted in increased oil production and increased production of associated gas.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

As indicated above, we projected 449 wells (not including coalbed natural gas wells) would be drilled within the Study Area during the analysis period of 2010 through 2029. We also assume that 24 wells will be drilled each year for the years 2008 and 2009. A table projecting wells spudded by year, for the 2010 through 2029 period, was calculated along with a confidence interval of values (Table 5). These values were determined by using a GNU Octave program that was written to statistically analyze the available historical drilling and production data constrained by oil and gas futures prices and projected drilling activities (449 new wells in 20 years) to generate the values in the projection tables provided here. Although Table 5 projects a range of new wells that could be drilled each year, the mean value projected should be considered the most likely scenario for new drilling in any one year and cumulatively for the 20-year period. As stated earlier, we expect that if coalbed natural gas drilling does occur that activity will only come about toward the end of the 20-year assessment period and drilling will be in groups of 16 to 25 wells.

Table 6 is our forecast of hydrocarbon production for 20 years beyond 2009. The estimated production is tied to the projection of wells that could be drilled and become productive to 2029. If the projection of future wells is not achieved, then the projection of associated future production will also not be met. Table 6 shows that gas and oil production will increase during the period. The cumulative values listed are just for the 2008 through 2029 projection period and ignore historical production. Of the 39,988,736 barrels of cumulative oil production, about 8,374,185 barrels are projected to come from Bureau managed oil and gas minerals. Of the 370,263,838,000 cubic feet of projected cumulative gas production, about 77,538,303,250 cubic feet are projected to come from Bureau managed oil and gas minerals. As stated above, these production projections are tied to a statistical analysis of wells drilled and our estimates of associated production is spread over the analysis period. It is important to recognize that these quantities are not as precise as they seem and actual annual and cumulative production rates will vary from those we project. They are provided so that restrictions that may be placed on oil and gas development during the environmental impact analysis can be compared and analyzed for each alternative studied.

Both oil and gas development will be driven predominantly by infill and fringe drilling and testing shallower horizons to minimize both drilling and completion costs while simultaneously monitoring futures prices and pipeline capacity. Operator’s prospect inventory will drive exploration. They will most likely use competing economic models to minimize their exposure to risk as applied to acreages they hold and to acreages they want to acquire. Each operator establishes their own level of acceptable risk, thus some will be interested in pursuing certain high risk prospects while others will not be interested in those same prospects. Prospects in the Study Area will be competing against other prospects of interest to operators in other basins not only in the U.S. but potentially around the world as operators continually adjust their prospect inventory.

Coalbed natural gas production was not assessed. If any coalbed natural gas production does come online during the 20-year assessment period it will only be minor part of the total gas production between 2010 and 2029.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

Natural gas resources are potentially present in shales in the Study Area; however, currently there are no known shale gas resource plays that extend into South Dakota. The Bakken Shale play, in parts of the Williston Basin north of the Study Area, has been shown to have a depositional limit north of the border with North Dakota (Pollastro, et al. 2008). Several other carbonaceous shales are present within the Study Area, but their potential for containing economic gas resources is unknown. At present, there is little information available to characterize any shale gas plays that may be present within the Study Area.

Carbonaceous shale is expected to be an important future source of natural gas in the United States. At present, technology and completion methods are not available to economically produce any present natural gas that may be contained in shale in the Study Area. However, this important future gas source could become viable before the end of the planning cycle.

When and if a shale gas play is characterized for the Study Area and technology and well completion methods are developed, this potential energy source could become important. Future development of such a play would depend heavily on its location relative to plays already developed/developing in the Study Area. If adjacent to or overlapping existing plays, development would likely commence at a faster rate than if found to be geographically separated from such areas. Existing play areas have in place the existing infrastructure; existing wellbores may also be utilized if the plays overlap aerially. However, the nature of shale gas plays would likely require drilling of horizontal wells, so the existing wellbores would still have to be re-entered and a horizontal lateral drilled into the zone of interest using the existing wellbore as a pilot. Additional new horizontal wells would also likely be drilled. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). This production may be accompanied by significant volumes of water. Also, well spacing may be dense; one well per 40 acres should be expected for vertical wells and 80- to 160-acre spacing for horizontal wells. Opportunities for development of any shale gas resource in the Study Area appear to be very low for the period extending through 2030.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Study Area. This process burns the coal in-situ, producing a combustible gas with a low heating value that may be used in industrial processes and gas turbines. Air or oxygen commingled with steam is injected into the coal seam resulting in the coal being burned 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. The removal of volatile matter is essentially the same process that coal goes through in the geologic process of changing from lignite to anthracite by adding geothermal heat (increasing burial depth) and geologic time.

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 gas with a higher heating value. The limiting factor in depth would be potential reduced permeability of the coal and the ability to efficiently inject and produce the gas.

Underground coal gasification uses essentially the same injection/production process that is utilized in water flooding oil reservoirs and in the carbon dioxide tertiary oil recovery process. 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 within the Study Area.

Currently, this technology involving deep coal beds does not appear to be economic and there is no known research activity into future development in the Study Area. There are coal beds in the Study Area at depths too deep for mining but good candidates for underground gasification (e.g., Williston Basin Cretaceous and Tertiary coals); however, considering the relatively experimental status of underground coal gasification and the abundant coal found elsewhere in the region, there is a low probability that this process will be utilized in the Study Area in the next 20 years.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas, a greenhouse gas. The primary industrial sources for carbon dioxide include electrical power plants, oil refineries, chemical refineries, agricultural processing plants, cement works, and iron and steel production. In the Study Area, only power and cement plants and petroleum and natural gas processing (associated with pipeline infrastructure) have been identified as the major industrial sources of carbon dioxide (U.S. Department of Energy, 2007). Capturing and storing this gas has been proposed to reduce the environmental effects caused by releases of this gas. Three types of geologic formations have been identified as potential carbon dioxide sequestrations sites (U.S. Department of Energy, 2007). Those formation types are:

- Oil and gas reservoirs – These reservoirs have hosted natural accumulations of oil and/or gas and could, in the future, be used to store carbon dioxide. The entrapment of hydrocarbons indicates that a containment seal is present and any associated water is assumed to be non-potable. Larger oil and gas reservoirs in the Study Area such as Buffalo Field in north-central Harding County could be considered for sequestration. Carbon dioxide injected into a mature oil reservoir can enable incremental oil to be recovered. An additional 10 to 15 percent of original oil-in-place can be recovered when carbon dioxide is injected. Buffalo Field is already undergoing secondary recovery efforts using in situ combustion, and carbon dioxide injection, if a source were readily available, may be another secondary recovery option that would further enhance recovery. Due to the relatively small size of most oil reservoirs in the Study Area compared to reservoirs in neighboring states, it is unlikely that carbon dioxide injection for sequestration purposes only (i.e., not as a benefit of carbon dioxide secondary oil recovery) will be pursued prior to the end of the planning cycle.

- Unmineable coal seams – These types of coal seams are considered to be those that are too deep or too thin to be economically mined. Most coals in the Study Area are found in the Williston Basin in the northern portion of the area. Many of these coals are too deep to be economically mined. If methane contained in Study Area coal beds becomes economically producible, then there could be a future opportunity to inject carbon dioxide, which could sweep additional methane from the coalbeds and allow adsorption by the coals of the carbon dioxide. Since coal beds preferentially adsorb carbon dioxide, they provide excellent storage sites. However, at present there are no existing plans to develop coals within the Study Area for coalbed natural gas production. It remains a possibility, however, that during the course of the planning cycle limited exploration and production of coalbed natural gas will commence. For instance, the Plains CO_2 Reduction Partnership is currently evaluating the sequestration potential of Fort Union lignite coals in the North Dakota portion of the Williston Basin (Nelson, et al. 2005). Initial data have confirmed that the target lignite seam has sufficient thickness to support a full test of its carbon dioxide sequestration potential (Plains CO_2 Reduction Partnership, 2008). Depending on the results of the study and the presence of similar lignite seams in the South Dakota portion of the Williston Basin, future carbon dioxide sequestration tests may also be performed in the Study Area. Future project development in the area depends both on successful tests and project development in North Dakota as well as a successful test in the Study Area and a nearby source of carbon dioxide for injection. It is unlikely that all these criteria will be met within the planning period; therefore, only limited activity associated with initial testing of potential lignite seams in the Study Area can be expected.

- Saline formations – Saline formations were defined in the U.S. Department of Energy (2007) atlas, as porous and permeable rocks containing water with total dissolved solids greater than 10,000 milligrams per liter, which has the capacity to store large volumes of carbon dioxide. They are somewhat more extensive than coal seams or oil- and gas-bearing rocks in the Study Area, and thus have a large potential for carbon dioxide storage. Many of these potential formations are made up of reactive carbonate rocks that could potentially react with and convert the carbon dioxide into compounds for storage in the host rock.

PIPELINE INFRASTRUCTURE

Shortfalls in pipeline capacity have been common in the Rocky Mountain region in recent years. These shortfalls appear to be the result of rapid growth in supply, which has outstripped construction of new pipelines. The National Petroleum Council (2003) projects that significant new infrastructure will be needed in the Rocky Mountain region through 2013 and then the need will decrease after that. Compared to surrounding states, South Dakota produces relatively little natural gas from its existing fields in the Study Area. The only major pipeline supporting the gas produced in the Study Area is the Williston Basin Interstate Pipeline Company pipeline which runs from its terminus in Rapid City north through Lawrence, Butte, and Harding counties and enters North Dakota near the northwest corner of Harding County after passing the area's northern oil and gas fields. No major pipeline construction appears to be planned for the Study Area in the near term.

POTENTIAL SURFACE DISTURBANCE

Table 7 projects short-term and long-term disturbance associated with existing wells and projected drilling activity for 2010 through 2029. The method used to determine the number of new wells drilled during this period has been previously discussed. In addition, we assumed that:

- 28 additional wells (seven classed as gas wells and 21 classed as oil wells) will be drilled between August 2008 and December 2009,
- of the existing active wells in August 2008, 75 gas wells and 37 oil wells will be abandoned by December 2029,
- of the new producing wells drilled between August 2008 and December 2029, all will remain in an unplugged status,
- the success rate of new coalbed natural gas wells will be 90 percent, and
- the success rate of new noncoalbed oil and gas wells will be 60 percent as determined by the previous 20 years of drilling history.

Table 7a shows our projection of new exploratory and development wells (524 wells with 98 of those wells managed by the Bureau) that could be drilled in the Study Area from 2010-2029. There are an additional 408 existing active wells (South Dakota Department of Environment and Natural Resources, 2008d), as of August 2008 and 28 projected new active wells that will be drilled between August 2008 and December 2009, for a total of

436 existing and projected oil and gas wells. Of those 436 existing and projected wells; 65 total wells (33 gas wells and 32 oil wells) will lie on Bureau managed oil and gas minerals. Table 7a also projects associated acres of total surface disturbance (short-term disturbance) directly associated with all new wells, existing wells (as of August 2009) and projected new wells that will be drilled between August 2008 and December 2009. Approximately 2,531 acres of new short-term surface disturbance (520 acres of disturbance on Bureau managed oil and gas minerals) could occur if all 524 projected wells are drilled. Total short-term surface disturbance (for all well types) would be 3,659 acres, with 642 of those acres on Bureau managed oil and gas minerals.

Table 7b shows the calculation for new producing wells remaining in production after all new exploratory and development wells are drilled and all dry holes are abandoned and reclaimed (337 total new producing wells with 60 of those new producing wells on Bureau managed oil and gas minerals). There are an additional 313 existing and projected wells (37 projected active wells will lie on Bureau managed oil and gas minerals) that will remain active after some formerly existing producing wells cease to be productive and are abandoned, and after dry holes are removed from those projected to be drilled from August 2008 through December 2009. Table 7b also shows calculations for unreclaimed associated acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 731 acres of new unreclaimed surface disturbance (148 acres of unreclaimed Bureau managed oil and gas minerals) could remain in the long-term. Total unreclaimed long-term surface disturbance (for all well types) would be 1,669 acres, with 239 of those acres on Bureau managed oil and gas minerals.

SUMMARY

For our base-line projection we analyzed the oil and gas resource within the Study Area, discussed types of future development that may occur, estimated the development potential for each type of resource, and projected base-line activity levels for the period 2008 through 2029. For our analysis of the base-line projection, we assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed. Projections of future well numbers, oil and gas production, and surface disturbance were prepared.

REFERENCES

Beeman, W. R., Obuch, R. C., and Brewton, J. D., 1996, Digital map data, text, and graphical images in support of the 1995 National Assessment of United States oil and gas resources: U.S. Geological Survey Digital Data Series 35.

Bereskin, B. and M. Mavor, 2003, Shale gas geology and engineering: an overview. Course notes available from American Association of Petroleum Geologists, 1444 South Boulder Avenue, Tulsa, Oklahoma, 74119, 135 pp.

Boswell, R.M., A. Douds, H.R. Pratt, K.R. Bruner, K.K. Rose, J.A. Pancake, V.A. Kuuskraa, and R.L. Billingsley, 2002, Assessing technology needs of "sub-economic" gas resources in Rocky Mountain Basins: Gas Tips volume 8, number 3, p. 4-12.

Boswell, R.S., 2006, Impediments to Developing Unconventional Natural Gas Resource Plays: presented at "14th Annual EIA Energy Outlook and Modeling Conference," March 27, 2006, downloaded from http://www.eia.doe.gov/oiaf/aeo/conf/boswell/boswell.ppt.

Bretz, R.G., R.L. Stach, M.J. Tipton, and L.R. Rice, 1976, Status of mineral resource information for the Cheyenne River Indian Reservation, South Dakota: Bureau of Indian Affairs Administrative Report BIA-23, 64 pages, downloaded from http://www1.eere.energy.gov/tribalenergy/guide/fossil_fuel_resources.html .

Brown, D., 2006, Slimhole CTD Targets Shallow Plays: AAPG Explorer magazine, volume 27, number 12, pages 8 and 10.

Bureau of Indian Affairs, 1997, Atlas of oil and gas plays on American Indian Reservations: northern Rocky Mountain Tribes: published by Bureau of Indian Affairs and Colorado School of Mines, BIA Publication No. G-97-2 (Rev.1), 96 pages.

Cardinal, D.G., and M. Sherer, 1984, Alum Creek, Field, Fall River County, South Dakota: *in* Wyoming Geological Association 35th Annual Field Conference Guidebook, pages 169-182.

Carr, T.R., Mason, E.P., and Feazel, C.T. (eds.), Horizontal Wells – Focus on the Reservoir; AAPG Methods in Exploration Series No. 14, 270 pp.

Central Region Energy Resources Team, 1996, The importance of reserve growth to the nation's supply of natural gas: U.S. Geologic Survey Fact Sheet FS-202-96, 3 pages downloaded from http://pubs.usgs.gov/fs/fs-202-96/FS-202-96.html.

Charpentier, R. R., Klett, T. R., Obuch, R. C., and Brewton, J. D., 1996, Tabular data, text, and graphical images in support of the 1995 National Assessment of United States oil and gas resources: U.S. Geological Survey Digital Data Series 36.

Chimney, P.J., C.E. Treska, and C.A. Wolosin, 1992, Richardton/Taylor Fields—U.S.A. Williston Basin, North Dakota: American Association of Petroleum Geologists Treatise, Stratigraphic Traps III, p. 421 – 425.

Cleveland, C.J., 2003, A Preliminary Economic Assessment of Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to Their Development: CEES Working Paper Series #0301, 12 pages, downloaded from http://www.earthscape.org/rl/ES16302/EPCA_Study.pdf.

Cook, Lance, 2002, Personal conversation with Fred Crockett in April, 2002 about long-term gas price projections for Wyoming and coalbed gas exploration. Cook is the Wyoming State Geologist.

Cox, L.J., and R.A. Beach, 1980, Status of mineral resource information for the Lower Brule Indian Reservation, South Dakota: Bureau of Indian Affairs Administrative Report BIA-74, 28 pages, downloaded from http://www1.eere.energy.gov/tribalenergy/guide/fossil_fuel_resources.html .

Curry, W.H., 1971 Summary of possible future petroleum potential, Region 4, Northern Rocky Mountains: American Association of Petroleum Geologists Memoir 15, p. 538-546.

Curtis, J.B., and S.L. Montgomery, 2002, Recoverable natural gas resource of the United States: Summary of recent estimates: American Association of Petroleum Geologists Bulletin, volume 86, number 10, p. 1671-1678.

Duda, J.R., and G. Covatch, 2005, Projections of marginal wells and their contributions to oil and natural gas supplies, 2005 Society of Petroleum Engineers Eastern Regional Meeting, SPE 98014, 11 pages.

Dyman, T.S., D.T. Nielsen, R.C. Obuch, J.K. Baird, and R.A. Wise, 1990, Deep oil and gas wells and reservoirs in the United States from the Well History Control System and Petroleum Data System, *in* L.M.H. Carter, ed., USGS Research on Energy Resources: U.S. Geological Survey Circular 1060, p. 27-28.

Dyman, T.S., D.D. Rice, D.T. Nielsen, R.C. Obuch, and J.K. Baird, 1993a, Geologic and production characteristics of deep oil and gas wells and reservoirs in the conterminous U.S.: Oklahoma Geological Survey Circular 95, P. 208-215.

Dyman, T.S., D.D. Rice, J.W. Schmoker, C.J. Wandrey, R.C. Burruss, R.A. Crovelli, G.L. Dolton, T.C. Hester, C.W. Keighin, J.G. Palacas, W.J. Perry, Jr., L.C. Price, C.W. Spencer, and D.K. Vaughan, 1993b, Geologic studies of deep natural-gas resources in the United States: U.S. Geological Survey Professional Paper 1570, p. 171-203.

Dyman, T.S., D.D. Rice, and P.A. Westcott, eds., 1997, Geologic controls of deep natural gas resources in the United States: U.S. Geological Survey Bulletin 2146, 239 pages.

Energy Information Administration, 2003, U.S. crude oil, natural gas, and natural gas liquids reserves 2002 annual report: U.S. Department of Energy, Office of Oil and Gas, Energy Information Administration; DOE/EIA-0216(2002), 170 pages.

Energy Information Administration, 2004, Annual energy outlook 2004 with projections to 2025: U.S. Department of Energy, Office of Oil and Gas, Energy Information Administration; DOE/EIA-0383(2004), 263 pages or at http://eia.doe.gov/oiaf/aeo/index.html.

Energy Information Administration, 2005, Overview of the Annual Energy Outlook 2005, presented by J.J. Conti at 2005 EIA Midterm Analysis and Forecasting Conference in Washington, DC on April 12, 2005.

Energy Information Administration, 2006, Annual energy outlook 2006 with projections to 2030: U.S. Department of Energy, Office of Oil and Gas, Energy Information Administration; DOE/EIA-0383(2006), 221 pages.

Energy Information Administration 2007a, U.S. crude oil, natural gas, and natural gas liquids reserves 2006 annual report: DOE/EIA-0216(2007), 162 pages or from http://www.eia.doe.gov?neic/infosheets/petroleumreserves.html.

Energy Information Administration, 2007b, Assumptions to the Annual Energy Outlook 2007 with projections to 2030: U.S. Department of Energy, Office of Oil and Gas, Energy Information Administration; DOE/EIA-0554(2007), 176 pages.

Energy Information Administration, 2008a, Annual Energy Outlook 2009, Early Release, DOE/EIA 0383(2009), downloaded December 19, 2008 from http://www.eia.doe.gov/oiaf/aeo/index.html.

Energy Information Administration 2008b, Annual energy outlook 2008 with projections to 2030: U.S. Department of Energy, Office of Oil and Gas, Energy Information Administration; DOE/EIA-0383(2008), 224 pages or at http://eia.doe.gov/oiaf/aeo/index.html.

Energy Information Administration, 2008c, NYMEX Light Sweet Crude Oil Futures Prices, downloaded November 10, 2008 from http://www.eia.doe.gov/emeu/international/crude2.html.

EOG Resources http://pioneeroilproducers.com/feb09eog.pdf

Eustes, A.W. III, 2003, Directional Drilling Seminar; Course notes from BLM Directional Drilling Seminar held in Casper, Wyoming, March 18 and 19, 2003.

Fahrenbach, M.D., F.V. Steece, J.F. Sawyer, K.A. McCormick, G.L. McGillivray, L.D. Schulz, and J.A. Redden, 2007, South Dakota stratigraphic correlation chart: South Dakota Geological Survey, Oil and Gas Investigations 1, chart downloaded from http://www.state.sd.us/denr/DES/Mining/Oil&Gas/o&g-maps.htm .

Foss, M.M., 2007, United States natural gas prices to 2015: Oxford Institute for Energy Studies NG 18, 40 pages or from http://www.oxfordenergy.org/pdfs/NG18.pdf.

Fritz, R.D., Horn, M.K., and Joshi, S.D. (eds.), Geological Aspects of Horizontal Drilling; AAPG Continuing Education Course Note Series No. 33, 563 pp.

Gautier, D. L., Dolton, G. L., Takahashi, K. I., and Varnes, K. L., eds., 1996, 1995 National Assessment of United States oil and gas resources – results, methodology, and supporting data: U.S. Geological Survey Digital Data Series 30, version 2 corrected.

Gas Technology Institute, 2001, Tight gas resource map of the United States: GTI E&P Services, Des Plains, Illinois; GTI-01/0114, 1 map.

GeoShurr, 2008, Home page of GeoShurr Resources, LLC., downloaded from http://www.geoshurr.com/index.html .

Green, D.W., and Whillhite, G.P., 1998, Enhanced Oil Recovery; Society of Petroleum Engineers Textbook Series Volume 6, 545 pages.

Hester, T.C., 2006, Estimation of gas-production potential using well logs, Cretaceous of northern Montana: U.S. Geological Survey Scientific Investigations Report 2005-5082, 27 pages.

Humphries, M., 2004, Oil and gas exploration and development on public lands: Congressional Research Service Report for Congress, The Library of Congress, RL32315, 23 pages.

IHS Energy Group, 2008, Rocky Mountain US Well Data: Network License for PI/Dwights PLUS Version 1.7.

IOGCC, 2006, Marginal Wells: fuel for economic growth. Interstate Oil & Gas Compact Commission 2006 Report, 48 pages: downloaded March 14, 2007 at http://www.iogcc.state.ok.us.

Koottungal, L. (ed.), 2008, 2008 worldwide EOR survey; Oil & Gas Journal, vol. 106.15, p. 47-59.

LaTourrette, T., M. Bernstein, P. Holtberg, C. Pernin, B. Vollaard, M. Hanson, K. Anderson, and D. Knopman, 2002a, A New Approach to Assessing Gas and Oil Resources in the Intermountain West: RAND Issue Paper IP-225-WFHF, 8 pages, downloaded from http://www.rand.org/pubs/.

LaTourrette, T., M. Bernstein, P. Holtberg, C. Pernin, B. Vollaard, M. Hanson, K. Anderson, and D. Knopman, 2002b, A New Approach to Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework For a New Approach: RAND MR-1553-WFHF, 94 pages, downloaded from http://www.rand.org/pubs/.

LaTourrette, T., M. Bernstein, M. Hanson, C. Pernin, D. Knopman, and A. Overton, 2003, Assessing Natural Gas and Oil Resources: An Example of a New Approach in the Greater Green River Basin: RAND 112 pages, downloaded from http://www.rand.org/pubs/.

Likwartz, D., 2002, Personal conversation with Fred Crockett, of the Bureau of Land Management, in April 2002 about coalbed gas exploration in Wyoming. Likwartz is the State Oil and Gas Supervisor for the Wyoming Oil and Gas Conservation Commission.

McGillivray, M., 2008a, Personal communication with Al Elser, of the Bureau of Land Management, in July 2008 about enhanced oil recovery in South Dakota. McGillivray is the Senior Geologist with South Dakota Department of Natural Resources, Oil & Gas section of the Minerals and Mining Program.

McGillivray, 2008b, Personal communications with Alfred Elser in August, 2008. McGillivray is a Senior Geologist with the South Dakota Department of Environment and Natural resources.

Mackay, P., 2003, Reverse circulation drilling avoids damage to low-pressure gas reservoirs; World Oil Magazine, published March, 2003, downloaded May 7, 2007 from http://www.worldoil.com/.

Manrique, E.J., Muci, V.E., and Gurfinkel, M.E., 2006, EOR field experiences in carbonate reservoirs in the United States; Society of Petroleum Engineers 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, 22 pp.

Moritis, G., 2005, Special Report US Marginal Wells: US production relies greatly on strippers: Oil & Gas Journal, vol. 103, no. 21, p. 43-48.

National Petroleum Council, 1999, Meeting the Challenges of the Nation's Growing Natural Gas Demand, Volume 11, Task Group Reports, p. S-21.

National Petroleum Council, 2003, Balancing natural gas policy: Volume 1 Summary of findings and recommendations, 118 pages downloaded on 01-29-04, Volume 2 Integrated Report, 366 pages downloaded 04-22-04 and Volume 4 Supply task Group Report, 479 pages downloaded 06-11-07 from http://www.npc.org.

Nelson, R. N., Steadman, E. N., and Harju, J. A., 2005, Geologic CO_2 sequestration potential of lignite coal in the U.S. portion of the Williston Basin, Plains CO_2 Reduction Partnership, Scientific Topical Report, September 2005, 16 pp.

North Dakota Industrial Commission, 2008, Department of Mineral Resources, Oil and Gas Division website at https://www.dmr.nd.gov/oilgas/ .

Nummedal, D., Towler, B., Mason, C., and Allen, M. (eds.) 2003, Enhanced oil recovery in Wyoming: Prospects and challenges; University of Wyoming. Downloaded April, 2008 from http://uwadmnweb.uwyo.edu/AcadAffairs/PolicyStatements/EORfinal.pdf.

Plains CO_2 Reduction Partnership, 2008, CO_2 sequestration validation test in a deep, unmineable lignite seam in western North Dakota, Plains CO_2 Reduction Partnership Fact Sheet 10A, 2 pp.

Petak, K.R., 2007, Gas supply and demand in an uncertain environment: paper presented to 2007 EIA Energy Outlook, Modeling, and Data Conference in Washington DC, March 28, 2007; 21 pages downloaded from http://www.eia.doe.gov/oiaf/aeo/conf/pdf/petak.pdf.

Petres, Anthony, 1989, Identifying S. Dakotas hydrocarbon potential, Oil & Gas Journal, vol. 87, no. 13, p. 75-78.

Peterson, J.A., 1995, Williston Basin Province (031): U.S. Geological Survey 1995 Oil and Gas Assessment, 17 pages downloaded from http://certmapper.cr.usgs.gov/data/noga95/prov31/test/prov31.pdg .

Plains CO_2 Reduction Partnership, 2008, CO_2 sequestration validation test in a deep, unmineable lignite seam in western North Dakota, Plains CO_2 Reduction Partnership Fact Sheet 10A, 2 pp.

Pollastro, R.M., Cook, T.A., Roberts, L.N.R., Schenk, C.J., Lewan, M.D., Anna, L.O., Gaswirth, S.B., Lillis, P.G., Klett, T.R., and Charpentier, R.R., 2008, Assessment of undiscovered oil resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province, Montana and North Dakota, 2008: U.S. Geological Survey Fact Sheet 2008–3021, 2 p.

Potential Gas Committee, 2003, Potential supply of natural gas in the United States, report of the Potential Gas Committee (December 31, 2002), Darrell L. Pierce, President and General Chairman, Colorado School of Mines, Golden, Colorado, 316 pages.

Prothrock, E.P., 1947, Coal fields of northwestern South Dakota: South Dakota State Geological Survey, map. Downloaded from http://www.sdgs.usd.edu/digitalpubmaps/general.html .

PTTC (Petroleum Technology Transfer Council), 2002, Commercialization of the freeze-thaw/evaporation purification process: Rockies Newsletter, volume 5, number 2, page 1.

Rakhit Petroleum Consulting, LTD, 2007, Shallow gas in the Western Plains: downloaded from http://www.rpcl.com/Brochures/Shallow-Gas-Western-Plains.pdf.

Raymond, W.H., R.U. King, and J.P. Gries, 1976, Status of mineral resource information for the Pine Ridge Indian Reservation, South Dakota: Bureau of Indian Affairs Administrative Report BIA-12, 64 pages, http://www1.eere.energy.gov/tribalenergy/guide/fossil_fuel_resources.html .

Rice, D.D., and G.E. Claypool, 1981, Generation, accumulation, and resource potential of biogenic gas: American Association of Petroleum Geologists Bulletin, volume 65, number 1, p. 5-25.

Rice, L.R., and R. Bretz, 1978, Status of mineral resource information for the Standing Rock Indian Reservation, North Dakota and South Dakota: Bureau of Indian Affairs Administrative Report BIA-41, 58 pages or downloaded from http://www1.eere.energy.gov/tribalenergy/guide/fossil_fuel_resources.html .

Rocky Mountain Federal Leadership Forum, 2002, Reasonably foreseeable development scenarios and cumulative effects analysis; *for oil and gas activities on Federal lands in the greater Rocky Mountain region*: U.S.D.I Bureau of Land Management, U.S. Environmental Protection Agency, U.S.D.I. Fish and Wildlife Service, U.S.D.I. National Park Service, and U.S.D.A Forest Service: final draft published August 30, 2002.

Rocky Mountain Oil Journal, 2005, News Periodical: volume 85, number 35.

Sandrea, I., and Sandrea, R., 2007, Global oil resserves-1: Recovery factory leave vast target for EOR technologies; Oil & Gas Journal, vol. 105, issue 42: Downloaded from Oil & Gas Journal web site February, 2008.

Schmoker, J.W., 2003, U.S. Geological Survey assessment concepts for continuous petroleum accumulations: in chapter 19 of Petroleum Systems and Geologic Assessment of Oil and Gas in the Unita-Piceance Province, Utah and Colorado, U.S. Geological Survey Digital Data Series DDS-69-B.

Schmoker, J.W., and T.R. Klett, 2003, U.S. Geological Survey assessment concepts for conventional petroleum accumulations: in chapter 19 of Petroleum Systems and Geologic Assessment of Oil and Gas in the Unita-Piceance Province, Utah and Colorado, U.S. Geological Survey Digital Data Series DDS-69-B.

Seismic Exchange, Inc. (2008), SEI Search coverage map of South Dakota: map obtained from Seismic Exchange, Inc. on August 13, 2008.

Shurr, G.W., 2001, Basin-margin gas in the Rocky Mountains and adjacent plains: *in* Gas in the Rockies, D. Anderson, et al. eds., Rocky Mountain Association of Geologists, p. 223-239.

Shurr, G.W., T. Haggar, and S.A. Chadima, 2006, Exploration strategies for ultra-shallow microbial methane on the eastern margin of the Williston Basin: presented at American Association of Petroleum Geologists Annual Convention in Houston, Texas in April, 2006, downloaded from http://www.state.sd.us/denr/DES/Mining/Oil&Gas/50th_Anniversary.htm .

Shurr, G.W., and J.L. Ridgley, 2002, Unconventional shallow biogenic gas systems: American Association of Petroleum Geologists Bulletin, volume 86, number 11, p. 1939-1969.

Sieminski, A, 2007, Secrets of energy price forecasting: paper presented to 2007 EIA Energy Outlook, Modeling, and Data Conference in Washington DC, March 28, 2007; 20 pages downloaded from http://www.eia.doe.gov/oiaf/aeo/conf/pdf/sieminski.pdf.

Sieminski, A., 2008, Oil Market Issues and Outlook: Select Committee on Energy Independence and Global Warming, U.S. House of representatives, June 11 2008. Downloaded from http://globalwarming.house.gov/tools/2q08materials/files/0056.pdf .

Smith Technologies, 2008, S.T.A.T.S.: downloaded from http://www.smith.com/stats/new/ .

South Dakota Department of Environment and Natural Resources, 2008a, Online database of well permits http://www.state.sd.us/denr/DES/Mining/Oil&Gas/NewPermit.htm.

South Dakota Department of Environment and Natural Resources, 2008b, 2007 Oil and Gas Stripper Well Reports, downloaded on 08-06-08 from http://www.state.sd.us/denr/DES/Mining/Oil&Gas/producti.htm .

South Dakota Department of Environment and Natural Resources, 2008c, South Dakota field and well maps: downloaded from http://www.state.sd.us.denr/DES/Mining/Oil&Gas/o&g-maps.htm .

South Dakota Department of Environment and Natural Resources, 2008d, South Dakota online oil/gas/injection well data: downloaded from http://www.state.sd.us/denr/DES/Mining/Oil&Gas/well_data.htm

Spears & Associates, Inc, 2003, U.S. Department of Energy microhole initiative workshop summary: Downloaded on 01-29-04, from http://www.fossil.energy.gov/programs/oilgas/microhole/microhole-workshop-report.pdf.

Steece, F.V., and M. McGillivray, 2005, Pierre Gas Field revisited: South Dakota Department of Environment and Natural Resources Oil & Gas Section, presented at Geological Society of America meeting in Minneapolis, Minnesota May 19-20, 2005: online presentation downloaded from http://www.state.sd.us/denr/DES/Mining/Oil&Gas/50th_Anniversary.htm .

U.S. Department of Energy, 1999, Environmental benefits of advanced oil and gas exploration and production technology: DOE-FE-0385, 168 pages.

U.S. Department of Energy, 2005, Coiled tubing: state of the industry and role for NETL: Topical report prepared for U.S. Department of Energy, National Energy Technology Laboratory under contract DE-AD26-00Nt00612, 32 pages, downloaded from http://www.netl.doe.gov/technologies/oil-gas/publications/AP/Coiled%20Tubing%20Topical%20Report%20June%202005.pdf.

U.S. Department of Energy, 2003, Rocky Mountain states natural gas, resource potential and prerequisites to expanded production: Office of Fossil Energy DOE/FE-0460, 30 pages or at http://www.fossil.energy.gov/programs/oilgas/publications/naturalgas/rockymtn_final.pdf

U.S. Department of Energy, 2007, Carbon sequestration atlas of the United States and Canada: downloadable from http://www.netl.doe.gov/publications/carbon_seq/atlas/index.html.

U.S. Department of Energy, 2008, Enhanced oil recovery/CO2 Injection: Downloaded from the U.S. Department of Energy web site April, 2008: http://www.fossil.Energy.gov/programs/oilgas/eor/.

U.S. Departments of the Interior, Agriculture and Energy, 2003, Scientific inventory of onshore Federal lands' oil and gas resources and reserves and the extent and nature of restrictions or impediments to their development–The Paradox/San Juan, Uinta/Piceance, Greater Green River, and Powder River basins and the Montana Thrust Belt: BLM/WO/GI-03/002+3100 *or at* http://www.blm.gov/epca/.

U.S. Departments of the Interior, Agriculture and Energy, 2006, Scientific inventory of onshore Federal lands' oil and gas resources and reserves and the extent and nature of restrictions or impediments to their development–Phase II Cumulative Inventory: Northern Alaska, Montana Thrust Belt, Powder River Basin, Wyoming Thrust Belt, Greater Green River Basin, Denver Basin, Uinta/Piceance Basin, Paradox/San Juan Basins, Appalachian Basin, Black Warrior Basin and Florida Peninsula: BLM/WO/GI-03/002+3100/REV06 *or at* http://www.blm.gov/epca/.

U.S. Departments of the Interior, Agriculture, and Energy, 2008, Inventory of onshore Federal oil and natural gas resources and restrictions to their development–Phase II Inventory: onshore United States: BLM/WO/GI-03/002+3100/REV08, 430 pages *or at* http://www.doi.gov/ or http://www.blm.gov/.

U.S. Geological Survey, 2001a, Coal map of North America: USGS Special Geologic Map with pamphlet.

U.S. Geological Survey, Eastern Energy Team; John Tully (comp.), 2001b, Coal Fields of the United States: National Atlas of the United States, Reston, VA. Downloaded from http://nationalatlas.gov/atlasftp.html.

U.S. Geological Survey, 2003, 2002 USGS assessment of oil and gas resource potential of the Denver Basin Province of Colorado, Kansas, Nebraska, South Dakota, and Wyoming: USGS Fact Sheet FS-002-03, 3 pages or downloaded from http://energy.cr.usgs.gov/oilgas/noga/ .

U.S. Geological Survey, 2007, Petroleum systems and assessment of undiscovered oil and gas in the Denver Basin Province, Colorado, Kansas, Nebraska, South Dakota, and Wyoming—USGS Province 39, USGS Digital Data Series DDS-69-P.

U.S. Geological Survey, 2008a, Produced waters database: downloaded in August 2008 from http://energy.cr.usgs.gov/prov/prodwat/intro.htm.

U.S. Geological Survey, 2008b, National oil and gas assessment: province, play, and assessment unit boundaries for Denver Basin and Sioux Arch provinces downloaded from http://energy.cr.usgs.gov/oilgas/noga/.

U.S. Geological Survey, 2008c, Assessment of Undiscovered oil and gas resources of the Williston Basin Province of North Dakota, Montana, and South Dakota, 2008: U.G. Geological Survey Fact Sheet 2008-3092, 2 pages, downloaded from http://pubs.usgs.gov/fs/2008/3021/.

U.S. Geological Survey, 2009, National oil and gas assessment: province and assessment unit boundaries for Williston Basin province downloaded from http://energy.cr.usgs.gov/oilgas/noga/.

Veil, J.A., B.G. Langhus, and S. Belieu, 1999, Feasibility evaluation of downhole oil/water separator (DOWS) technology: for U.S. DOE Office of Fossil Energy, National Petroleum Technology Office, Contract W-31-109-Eng-38, downloaded from http://www.evs.anl.gov/pub/doc/dows.pdf.

Vidas, E.H., R.H. Hugman, and P.S. Springer, 2003, Assessing Natural Gas and Oil Resources: Technical Details of Resource allocation and Economic Analysis: RAND, 79 pages, downloaded from http://www.rand.org/pubs/.

Ward, Freeman, 1917, Oil in South Dakota, South Dakota Geological and Natural History Survey, Circular No. 1, 5 pp.

Ward, Freeman, 1918, The possibilities of oil and gas in Harding County, South Dakota Geological and Natural History Survey, Circular No. 4, 85 pp.

Williams, E.T., and M. Pitts, 1997, Application of enhanced oil recovery in the Rocky Mountain region: in E.B. Coalson, et al. eds., Innovative Applications of Petroleum Technology in the Rocky Mountain Area: Rocky Mountain Association of Geologists Guidebook, Denver, CO, p. 225-240.

Wood, Jr., G.H., and Bour, III, W.V., 1988, Coal Map of North America, south sheet: U.S. Geological Survey, Reston, VA.

APPENDIX 1 - U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED OIL AND GAS RESOURCES WITHIN THE STUDY AREA

INTRODUCTION

The U.S. Geological Survey has published a number of resource assessments of undiscovered oil and gas resources that cover parts of the Study Area. Their "1995 National Assessment of United States Oil and Gas Resources" (Beeman, et al. 1996: Charpentier, et al. 1996: and 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. Three of those provinces, the Williston Basin, Denver Basin, and Sioux Arch provinces, lie partly within the Study Area.

Recently the U.S. Geological Survey revised their methods of preparing oil and gas resource assessments. They have used their new method to update their quantitative estimate of the undiscovered oil and gas resource for other parts of the United States, including the Denver Basin Province (U.S. Geological Survey; 2003, 2007, and 2008b). In addition, they updated their quantitative analysis of the Williston Basin Province (U.S. Geological Survey, 2008b and 2008c). In the following analysis, we will use the newest assessments to describe the potential undiscovered technically recoverable oil and gas resources lying within the Denver Basin and Williston Basin provinces and the older assessments to describe those resources for the Sioux Arch province. Figure A1-1 shows the location of each of these three provinces and their relation to the Study Area.

DENVER BASIN PROVINCE ASSESSMENT

The Denver Basin Province lies in the southwestern portion (Fall River, Custer, and Shannon counties) of South Dakota and the Study Area (Figure A1-1). The Province is an asymmetrical Laramide-age structural basin. The northeast portion of the Denver Basin Province within South Dakota is bounded on the north by the Black Hills Uplift and to the east by the Sioux Arch. Only a limited number of hydrocarbon accumulations in the province lie within the Study Area. The Alum Creek and Hollingsworth East fields have been the most prolific, producing from the Pennsylvanian Minnelusa Formation (informally known as the Leo Sandstone). A summary of past oil and gas related activities in the Study Area portion of the province is presented in the main body of this report.

<u>Assessment Unit Summaries</u>

In their newest assessment, the U.S. Geological Survey (2003 and 2007) divided the Denver Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays" as they had done in previous assessments. "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" (U.S. Departments of Interior, Agriculture, and Energy, 2003). Seven total petroleum systems have been identified in the Denver Basin Province, three of which lie at least partly within the Study Area (Lower Cretaceous, Permian-Pennsylvanian, and Upper Cretaceous Niobrara biogenic gas total petroleum systems). Two of these total petroleum systems each contain a conventional accumulation (see Glossary definition) called an assessment unit that lies at least partly within the Study Area (Figure A1-2). Each assessment unit occupies the same mapped boundary within the Study Area. Those accumulations are:

- Dakota Group and D Sandstone conventional gas and oil assessment unit, and
- Permian-Pennsylvanian Reservoirs conventional oil and gas assessment unit.

The U.S. Geological Survey has made available some statistical information for the two conventional assessment units (Table A1-1). Small quantities of sulfur can be expected to be produced from any oil recovered from each assessment unit. In addition, some small quantities of carbon dioxide and hydrogen-sulfide can be expected to be produced with any gas discovered in the Dakota Group and D Sandstone assessment unit.

The other total petroleum system (Upper Cretaceous Niobrara Biogenic Gas) contains one continuous accumulation (see Glossary definitions) that lies at least partly within the Study Area (Figure A1-3). Continuous accumulations can include tight reservoirs, shale reservoirs, unconventional reservoirs, basin-centered reservoirs, fractured reservoirs, coalbeds, oil shales, and shallow biogenic gas. The continuous accumulation lying within the Study Area is the Niobrara Chalk assessment unit. The Niobrara Chalk continuous oil assessment unit is considered to have an established exploration status for gas resources. Drilling depths for this assessment unit are expected to be relatively shallow (between 790 and 4,270 feet). The median well spacing is expected to be about 145 acres and median gas recovery is expected to be 0.2 billion cubic feet. Small amount of carbon dioxide could be present.

Assessment Unit Resource Results

The U.S. Geological Survey (2003 and 2007) 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 two conventional and one continuous assessment units, which both lie at least partly within the Study Area.

In Table A1-2, 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 Study Area. To determine the potential resource within the Study 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 Study Area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Study Area resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Study 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 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Study Area contains a **mean undiscovered volume of 5.07 million barrels of oil, 186.87 billion cubic feet of gas, and 0.40 million barrels of natural gas liquids, in the Denver Basin Province assessment units.**

In addition, we estimate that the Study Area's oil resource in the Denver Basin province could **range from 1.53 to 10.06 million barrels, the gas resource could range from 63.86 to 399.165 trillion cubic feet, and the natural gas liquids resource could range from 0.10 to 0.79 million barrels** (assuming fractile data used has a perfect positive correlation).

WILLISTON BASIN PROVINCE ASSESSMENT

The Williston Basin Province occupies the northern two-thirds of the Study Area (Figure A1-1). It is a structural-sedimentary intracratonic basin in a generally flat lying, moderately dissected plain with minimum topographic relief. The southern portion of the Williston Basin Province within South Dakota is bounded on the south by the Black Hills Uplift and to the east by the Sioux Arch. A portion of the Cedar Creek Anticline is the main province geologic feature lying in the Study Area. It lies in the northwest corner of the Study Area. The largest Study Area oil fields produce from the Late Ordovician Red River Formation and are; Buffalo, Travers Ranch, Harding Springs East, State Line, Yellow Hair, and Medicine Pole Hills South. The largest Study Area gas fields produce from the Pierre Shale (the producing zone is informally known as the Shannon Sandstone) and are called the Cady Creek and West Short Pine Hills.

Assessment Unit Summaries

In their newest assessment, the U.S. Geological Survey (2008b and 2008c) divided the Williston Basin Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays" as they had done in previous assessments. "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" (U.S. Departments of Interior, Agriculture, and

Energy, 2003). In the Williston Basin, two total petroleum systems are associated with continuous oil and gas resources and nine total petroleum systems are associated with conventional oil and gas resources. Only one continuous total petroleum system (Coalbed Gas) and five conventional total petroleum systems (Red River, Duperow, Cedar Creek Paleozoic Composite, Tyler, and Shallow Biogenic Gas) lie at least partly within the Study Area. Four of these total petroleum systems each contain only one accumulation (see Glossary definition) called an assessment unit that lies at least partly within the Study Area. One total petroleum system contains two assessment units and the other contains three assessment units. These total petroleum systems and their associated assessment units are:

- Coalbed Gas total petroleum system – Fort Union Coalbed Gas assessment unit (Figure A1-4).
- Red River total petroleum system – Red River Fairway (Figure A1-5), Interlake-Stonewall-Stony Mountain (Figure A1-5), and Red River East Margin (Figure A1-6),
- Duperow total petroleum system – Dawson Bay-Souris River and Duperow-Birdbear assessment units (Figure A1-7).
- Cedar Creek Paleozoic Composite total petroleum system – Cedar Creek Structural assessment unit (Figure A1-8).
- Tyler total petroleum system – Tyler Sandstone assessment unit (Figure A1-9), and
- Shallow Biogenic Gas total petroleum system – Shallow Biogenic Gas assessment unit (Figure A1-10).

The U.S. Geological Survey has not yet made statistical information, similar to that for the Denver Basin Province, available for the nine assessment units.

Assessment Unit Resource Results

The U.S. Geological Survey (2008b and 2008c) 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 8 conventional and one continuous assessment units, which lie at least partly within the Study Area.

In Table A1-3, 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 in the Williston Basin Province, together with our projection of the amount of those hydrocarbons that could be present within the Study Area. To determine the potential resource within the Study 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 Study Area, and
- multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit to calculate Study Area resource values.

Our estimates of recoverable resources for each assessment unit within the province and within the Study 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 5 percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. We estimate that the Study Area contains a **mean undiscovered volume of 9.11 million barrels of oil, 164.55 billion cubic feet of gas, and 1.70 million barrels of natural gas liquids, in the Williston Basin Province assessment units.**

In addition, we estimate that the Study Area's oil resource in the Williston Basin province could **range from 2.90 to 18.14 million barrels, the gas resource could range from 28.67 to 363.00 billion cubic feet, and the natural gas liquids resource could range from 0.48 to 3.48 million barrels** (assuming fractile data used has a perfect positive correlation).

SIOUX ARCH PROVINCE ASSESSMENT

The Sioux Arch Province occupies the southeastern part of the Study Area (Figure A1-1). In the Study Area, this province adjoins the Williston Basin Province on the north and the Denver Basin Province on the west. The Kennedy Basin is a slight downwarp that occupies most of the province lying within the Study Area. The Sioux Ridge is a broadly positive feature mostly lying to the east of the Study Area, with a small portion projecting into the Study Area. There are presently no producing wells in the Study Area portion of this province.

Play Summaries

The "1995 National Assessment of United States Oil and Gas Resources" (Beeman, et al. 1996: Charpentier, et al. 1996: Gautier, et al. 1996) in the Sioux Arch Province has not been updated with the latest U.S. Geologic Survey assessments of oil and gas resources. The assessment divided the Sioux Arch Province into two "play" areas.

The unconventional continuous-type Southern Williston Basin Margin-Niobrara Shallow Biogenic Play was originally described under the Williston Basin Province. The information on this play was then updated and has been included in our previously described Denver Basin Province assessment as the Upper Cretaceous Niobrara biogenic gas total petroleum system, Niobrara Chalk assessment unit (U.S. Geological Survey, 2003 and 2007), so it is not included here.

The Truncated Paleozoic Play is a hypothetical conventional play in truncated Paleozoic rocks that thin eastward and pinch out around the Sioux Ridge trend. Its location within the Study Area is shown in Figure A1-11. Since it is a hypothetical play the U.S. Geological Survey has not made any statistical information available, including estimated undiscovered technically recoverable resource quantities of oil and gas. A small amount of supporting geologic information for this play is available at Gautier, et al. (1996).

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.

Borehole. Any narrow shaft drilled in the earth, either vertically or horizontally, to explore for or release oil, gas, water, etc.

Casing string. An assembled length of steel pipe configured to suit a specific borehole. The sections of pipe are connected and lowered into a borehole, then cemented in place. Casing is run to protect or isolate formations next to the borehole.

Channeling and breakthrough. In the oil reservoir, injection fluids may preferentially move through a network of interconnecting channels that in some cases can cause that fluid to breakthrough into the boreholes of producing wells before it has had an opportunity to effectively sweep oil towards those boreholes.

Clastic. Pertaining to a rock or sediment composed principally of broken fragments that are derived from preexisting rocks or minerals and that have been transported some distance from their places or origin; also said of the texture of such a rock.

Coiled tubing. A long, continuous length of pipe wound on a spool. The pipe is straightened prior to pushing into a borehole and rewound to coil the pipe back onto the transport and storage spool.

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).

Craton. A part of the Earth’s crust that has attained stability, and has been little deformed for a prolonged period. The term is now restricted to continental areas.

Diagenetic pore-throat trap. A statigraphic configuration of the reservoir and/or its sealing units formed by post depositional processes that cause variations in pore-throat aperture sizes (constricted openings connecting pore spaces between sediment grains) that create the trap boundaries between the reservoir and seal.

Directional and Horizontal Drilling. Directional drilling is the intentional deviation of a wellbore from the path it would naturally take. Horizontal drilling is a subset of the more general term “directional drilling,” used where the departure of the wellbore from vertical exceeds about 80 degrees.

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.

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.

Injection well. A well in an oil or gas field through which water, gas, steam, or chemicals are pumped into the reservoir formation for maintenance of pressure, for secondary or enhanced oil recovery, or for storage or disposal of the injected fluid.

In-place resource. 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.

Intracratonic basin. A basin on top of a craton (see Glossary for craton).

Mud motor. A positive displacement drilling motor that uses hydraulic horsepower of the drilling fluid in the borehole to drive the drill bit. Mud motors are used extensively in directional drilling operations.

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.

Ovality. Distortion of the drilling string due to stress associated with the horizontal and directional drilling process. The mechanical performance of the drill strings decreases as ovality increases.

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 that geologic and engineering data demonstrate with reasonable certainty (defined as 90 percent or more probable) to be recoverable from known reservoirs under existing economic and operating 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. Identified oil and gas resources that have been proven to be productive by drilling and are available for profitable production.

Slimhole drilling. An inexact term describing a drilled borehole (and associated casing program) significantly smaller than a standard approach, commonly a wellbore drilled to less than six inches in diameter.

Spudded. To break ground with a drilling rig at the start of well-drilling operations.

Stratigraphic trap. A trap (any barrier to the upward movement of oil or gas, allowing either or both to accumulate) that is the result of lithologic changes rather than structural deformation.

Structure trap. A trap (any barrier to the upward movement of oil or gas, allowing either or both to accumulate) that is the result of folding, faulting, or other deformation.

Sweep efficiency. A measure of the effectiveness of an enhanced oil recovery process that depends on the volume of the reservoir contacted by the injected fluid.

Total petroleum system. A total petroleum system consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. Particular emphasis is placed on similarities of the fluids of petroleum accumulations and are therefore closely associated with the generation and migration of petroleum. It is characterized by: 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 base 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.

Unstable grains. Said of mineral grains within a sedimentary rock, that do not resist chemical change after deposition.

Updip. A direction that is upwards and parallel to the dip of a structure or surface. Dip is the angle that a structural surface makes with the horizontal.

Waterflood. A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells.