FINAL REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS
Rock Springs Field Office, Wyoming

July 1935 - American Oil Company Well #3, Baxter Basin Field, Section 18, township 18 north, range 103 west (Bureau files).

DEAN P. STILWELL

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

BLM/WY/PL-14/008+1310

September 25, 2013

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

WYOMING STATE OFFICE
RESERVOIR MANAGEMENT GROUP

FINAL

Reasonable Foreseeable Development Scenario for Oil and Gas, Rock Springs Field Office, Wyoming
September 25, 2013

Prepared By:

Signature

Dean P. Stilwell

Name

Geologist, PG-1070

Title

09/25/2013

Date

Reviewed By:

Signature

J. David Chase

Name

Chief Reservoir Mgmt. Group

Title

09/26/2013

Date

INTRODUCTION **11**

GEOLOGIC OVERVIEW **13**

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS **14**

EXPLORATORY ACTIVITY AND OPERATIONS **14**
EXPLORATORATION AND DEVELOPMENT ACTIVITY – 2002 TO 2012 **18**
CONVENTIONAL OIL AND GAS ACTIVITY 18
COALBED NATURAL GAS ACTIVITY 22
EXPLORATORATION AND DEVELOPMENT SUCCESS **24**
EXPLORATION ACTIVITY AND SUCCESS 24
DEVELOPMENT ACTIVITY AND SUCCESS 26
TECHNOLOGY AND COST **28**
FEDERAL DEVELOPMENT CONTRACTS **29**
FEDERAL OIL AND GAS UNIT AGREEMENTS **30**
CONVENTIONAL OIL AND GAS UNIT AGREEMENTS 31
COALBED NATURAL GAS UNIT AGREEMENTS 34
CONVENTIONAL OIL AND GAS COMMUNITIZATION AGREEMENTS 37
COALBED NATURAL GAS COMMUNITIZATION AGREEMENTS 38
TYPICAL DRILLING AND COMPLETION SEQUENCE **38**
DRAINAGE PROTECTION **40**
HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED FOR CONVENTIONAL OIL AND GAS **40**
EARLY EXPLORATION AND DEVELOPMENT ACTIVITY – 1900 THROUGH 1935 40
EXPLORATION AND DEVELOPMENT ACTIVITY – 1936 THROUGH 1948 42
EXPLORATION AND DEVELOPMENT ACTIVITY – 1949 THROUGH 1957 44
EXPLORATION AND DEVELOPMENT ACTIVITY – 1958 THROUGH 1963 46
1958 46
1959 47
1960 and 1961 48
1962 48
1963 49
Other wells 49
PRODUCING ZONES 50
TECHNOLOGY DEVELOPMENT 53
DRILLING AND COMPLETION ACTIVITY 54
Conventional wells 54
Coalbed natural gas wells 56
DRILLING RIGS AND RIG COUNTS 56
PRODUCTION 57
OIL MINING ACTIVITY 58

MARGINAL WELLS 58
DEEP WELL DRILLING: GREATER THAN 15,000 FEET 59
DEEP WELL DRILLING AND COMPLETION ACTIVITY: 10,000 TO 15,000 FEET 60
SHALLOWER WELL DRILLING: 5,000 TO 9,999 FEET 61
SHALLOWEST WELL DRILLING: LESS THAN 5,000 FEET 62
COALBED NATURAL GAS DRILLING DEPTHS 63
SUMMARY OF CURRENT DRILLING TECHNIQUES 63
Directional and Horizontal Drilling and Completion Activity 63
Slimhole Drilling and Coiled Tubing 66
Drilling with Casing 67
Light Modular Drilling Rigs and Pad Drilling 68
Pneumatic Drilling 68
Measurement-While-Drilling 68
Improved Drill Bits 68
SUMMARY OF CURRENT COMPLETION TECHNIQUES 69
SUMMARY OF CONVENTIONAL OIL AND GAS PRODUCTION AND ABANDONMENT TECHNIQUES 70
SECONDARY OIL RECOVERY 72
ENHANCED OIL RECOVERY 72
SECONDARY AND ENHANCED RECOVERY PROJECTS IN ROCK SPRINGS FIELD OFFICE PLANNING AREA 73
Waterflooding and Gas Injection 73
Steamflooding 73
Polymer-Enhanced Waterflooding 73
Surfactant Flooding 74
In-Situ Combustion (High Pressure Air Injection) 74
Carbon Dioxide Injection 74
HYDROGEN SULFIDE OCCURRENCE 75
ACID GAS REMOVAL AND RECOVERY 76
ARTIFICIAL LIFT OPTIMIZATION 76
GLYCOL DEHYDRATION 76
PRODUCED WATER MANAGEMENT 77
LEAK DETECTION AND LOW-BLEED EQUIPMENT 80
VAPOR RECOVERY UNITS 80
PLANT SITES 80
UNDERGROUND GAS STORAGE 80

U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED TECHNICALLY RECOVERABLE OIL AND GAS RESOURCES 81

PLAY SUMMARIES 82
ASSESSMNENT UNIT SUMMARIES 83
ASSESSMNENT UNIT AND PLAY RESOURCE RESULTS 84

DEPARTMENSTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS 85

RAND SCIENCE AND TECHNOLOGY RESOURCE ASSESSMENT 86

STATE OF WYOMING RESOURCE ASSESSMENT 86

OIL AND GAS OCCURRENCE POTENTIAL 87

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2012-2031 88

OIL AND GAS PRICE ESTIMATES 88
GAS PRICES 89
OIL PRICES 90
LEASING 91
PROJECTIONS OF FUTURE OIL AND GAS DRILLING ACTIVITY 92
PROJECTED CONVENTIONAL OIL AND GAS DRILLING ACTIVITY 92
PROJECTED COALBED NATURAL GAS DRILLING ACTIVITY 94
PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION 95
ESTIMATED FUTURE PRODUCTION 95
OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES 95
SHALE GAS 95
COAL GASIFICATION 96
CARBON DIOXIDE SEQUESTRATION 96

REASONABLLY FORESEEABLE DEVELOPMENT SCENARIOS FOR RESOURCE MANAGEMENT PLAN ALTERNATIVES A, B, AND C 98

PROCEDURES USED TO DETERMINE WELL LOCATION REDUCTIONS 98
ESTIMATED FUTURE OIL AND GAS PRODUCTION 100

POTENTIAL OIL AND GAS SURFACE DISTURBANCE 100

SUMMARY 103

REFERENCES 104

GLOSSARY 116

Figure List

Figure 1. The Rock Springs Field Office and its location within Wyoming.
Figure 2. Base map of Rock Springs Planning Area.
Figure 3. Location of Federal oil and gas mineral ownership within the Rock Spring Planning Area.
Figure 4a. Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area.
Figure 4b. Location and initial status of all coalbed natural gas wells drilled within the Rock Springs Planning Area.
Figure 5a. Major structural elements of the Rock Spring Planning Area.
Figure 5b. Major thrust faults and faults and selected geologic units of the Rock Springs Planning Area.
Figure 6. Generalized stratigraphic chart of the Southwestern Wyoming basin within the Planning Area (after Law, 1995; Kirschbaum *et al.*, 2002; and Finn and Johnson, Ch. 6, 2002), with hydrocarbon and carbon dioxide producing zones.
Figure 7. Oil and gas fields within the Rock Springs Planning Area.
Figure 8a. Location and initial classification of Rock Springs Planning area coalbed natural gas wells spudded between January 1, 2002 and April of 2012.
Figure 8b. Location and initial classification of Rock Springs Planning area oil and gas wells spudded between January 1, 2002 and April of 2012.
Figure 8c. Location and initial classification of Rock Springs Planning Area active drilling permits as of April of 2012.
Figure 9a. Location and initial status of Rock Springs Planning Area conventional oil and gas wildcat wells spudded between January 1, 1970 and December 31, 2011.
Figure 9b. Locations of successful and unsuccessful conventional wildcat oil and gas wells within Rock Springs Planning Area for certain time periods between January 1, 1970 and December 31, 2011.
Figure 9c. Location and initial status of Rocks Springs Planning Area conventional oil and gas development wells spudded between January 1, 1970 and December 31, 2011.
Figure 9d. Locations of successful and unsuccessful conventional development oil and gas wells within Rock Springs Planning Area for certain time periods between January 1, 1970 and December 31, 2011.
Figure 10. Locations of active conventional oil and gas units and townships with no historical units within the Rock Springs Planning Area.
Figure 11. Locations of terminated development contracts within the Rock Springs Planning Area.
Figure 12. Active and closed units, by year, within Rock Springs Planning Area.
Figure 13. Wells spudded by year within the Rock Springs Planning Area.
Figure 14a. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1900 through 1935.
Figure 14b. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1936 through 1948.

Figure 14c. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1949 through 1957.
Figure 14d. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1958 through 1963.
Figure 14e. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1964 through 1972.
Figure 14f. Location and initial status of all conventional oil and gas wells drilled within the Rocks Springs Planning Area from 1973 through 1983.
Figure 15. Location of active and closed coalbed natural gas units and initial completion status of wells within the Rock Springs Planning Area.
Figure 16. Coalbed natural gas wells spudded by year within the Rock Springs Planning Area.
Figure 17. Location of conventional and coalbed natural gas communitization agreements within the Rock Springs Planning Area.
Figure 18a. Locations of all wells completed in the Cretaceous Frontier Formation within the Planning Area.
Figure 18b. Locations of all wells completed in the Cretaceous Almond Formation within the Planning Area.
Figure 18c. Locations of all wells completed in the Cretaceous Dakota (Lakota) Formation within the Planning Area.
Figure 18d. Locations of all wells completed in the Cretaceous Lance Formation within the Planning Area.
Figure 18e. Locations of all wells completed in the Cretaceous Mesaverde Group (excluding the Almond Formation) within the Planning Area.
Figure 18f. Locations of all wells completed in the Cretaceous Lewis Shale within the Planning Area.
Figure 18g. Locations of all wells completed in Tertiary aged rocks within the Planning Area.
Figure 18h. Locations of all wells completed in Nugget Sandstone and older rocks within the Planning Area.
Figure 19a. Rock Springs Planning Area locations of all conventional oil and gas wells that have been spudded and not completed and those still capable of producing oil and gas.
Figure 19b. Rock Springs Planning Area locations of all conventional wells being used for enhanced oil recovery purposes (water injection, polymer enhanced flooding, surfactant flooding, and carbon dioxide injection), for disposal (acid gas and water disposal), monitoring, and as water source wells.
Figure 19c. Rock Springs Planning Area locations of all conventional well drilling permits (approved and waiting on approval).
Figure 19d. Rock Springs Planning Area locations of all abandoned conventional wells.
Figure 20. Rock Springs Planning Area locations and status of all coalbed natural gas related wells and permits.
Figure 21. Location of marginal oil and gas wells and shut-in or temporarily abandoned oil and gas wells within the Rock Springs Planning Area.

Figure 22a. All conventional wells in the Rock Springs Planning Area with a true vertical depth greater than 15,000 feet, initial well completion status, and fields productive at greater than 15,000 feet.
Figure 22b. All conventional wells in the Rock Springs Planning Area with a true vertical depth of 10,000 to 15,000 feet and their initial completion status.
Figure 22c. All conventional wells in the Rock Springs Planning Area with a true vertical depth of 5,000 to 9,999 feet and their initial completion status.
Figure 22d. All conventional wells in the Rock Springs Planning Area with a true vertical depth of less than 5,000 feet and their initial completion status.
Figure 23. Existing and proposed directional and horizontal borehole locations within the Rock Springs Planning Area.
Figure 24. Geographic distribution of water quality samples across the Rock Springs Planning Area and distribution of sample salinity.
Figure 25. Location of the 2002 Southwestern Wyoming Province boundary within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 26. Location of the 2002 Southwestern Wyoming Province Phosphoria Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 27. Location of the 2002 Southwestern Wyoming Province Mowry Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 28. Location of the 2002 Southwestern Wyoming Province Hilliard-Baxter-Mancos Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 29. Location of the 2002 Southwestern Wyoming Province Mesaverde Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 30. Location of the 2002 Southwestern Wyoming Province Mesaverde-Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 31. Location of the 2002 Southwestern Wyoming Province Lewis Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 32. Location of the 2002 Southwestern Wyoming Province Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 33. Location of the 2002 Southwestern Wyoming Province Mowry Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 34. Location of the 2002 Southwestern Wyoming Province Niobrara Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 35. Location of the 2002 Southwestern Wyoming Province Hilliard-Baxter-Mancos Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).

Figure 36. Location of the 2002 Southwestern Wyoming Province Mesaverde Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 37. Location of the 2002 Southwestern Wyoming Province Mesaverde-Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 38. Location of the 2002 Southwestern Wyoming Province Lewis Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 39. Location of the 2002 Southwestern Wyoming Province Total Petroleum System within the Rock Springs Planning Area Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 40. Location of the 2002 Southwestern Wyoming Province Wasatch-Green River Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).
Figure 41. Potential for occurrence of conventional oil and gas within the Rock Springs Planning Area.
Figure 42. Potential for occurrence of coalbed natural gas within the Rock Springs Planning Area.
Figure 43. Wyoming historical natural gas prices with future natural gas price projections (Energy Information Administration, 2012).
Figure 44. Wyoming historical crude oil prices with future crude oil price projections (Energy Information Administration, 2012).
Figure 45. Federal oil and gas minerals and authorized leases within the Rock Springs Planning Area.
Figure 46. Rock Springs Planning Area conventional oil and gas development potential for the analysis period (2012-2031).
Figure 47. Rock Springs Planning Area coalbed natural gas development potential for the analysis period (2012-2031).
Figure 48. Annual Wyoming crude oil production in thousand barrels.
Figure 49. Annual Wyoming natural gas production in thousand cubic feet.

Table List

Table 1. Wildcat and development well drilling within the Rock Springs Planning Area from 1970 through 2011.
Table 2. Unit cases closed within the Rock Springs Planning Area.
Table 3a. Active units within the Rock Springs Planning Area.
Table 3b. Active units, their township and range locations and initial well requirements within the Rock Springs Planning Area.
Table 4. Active and closed coalbed natural gas units within the Rock Springs Planning Area.
Table 5. Rock Springs Planning Area 2011 field production (Wyoming Oil and Gas Conservation Commission, 2012).
Table 6a. Direct Rocky Mountain annual operating costs for an average oil well in current dollars.
Table 6b. Direct Rocky Mountain annual operating costs for an average gas well in current dollars.
Table 7. Active water disposal wells in Rock Springs Planning Area.
Table 8. U.S. Geological Survey 2002 assessment of undiscovered conventional accumulation assessment units in the Southwestern Wyoming Province, Rock Springs Planning Area.
Table 9. U.S. Geological Survey 2002 assessment of undiscovered continuous accumulation assessment units in the Southwestern Wyoming Province, Rock Springs Planning Area.
Table 10. U.S. Geological Survey 2002 assessment of undiscovered conventional and continuous resource assessment units within the Southwestern Wyoming Province, Rock Springs Planning Area.
Table 11a. Estimated conventional oil and gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Rock Springs Planning Area within each development potential classification type.
Table 11b. Estimated conventional oil and gas development potential classification acres on Federal oil and gas minerals, number of townships, projected average drilling densities, and percentage of Federal oil and gas minerals within each development potential classification type.
Table 12a. Estimated coalbed natural gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Rock Springs Planning Area within each development potential classification type.
Table 12b. Estimated coalbed natural gas development potential classification acres on Federal oil and gas minerals, number of townships, projected average drilling densities, and percentage of Federal oil and gas minerals within each development potential classification type.
Table 13. Forecast of annual and cumulative baseline conventional oil and gas and coalbed natural gas production the Rock Springs Planning Area for 2012 through 2031.

Table 14. Alternative B summary of the number of acres in each restriction category for each development potential type within the Rock Springs Planning Area.

Table 15. Analysis results showing the calculated reduction in Bureau and non-Bureau wells of each type for Alternative B due to Category D restrictions within the Rock Springs Planning Area.

Table 16. Conventional and coalbed natural gas well counts, by alternative, for Bureau and Non-Bureau managed wells within the Rock Springs Planning Area.

Table 17. Forecast of annual and cumulative Alternative A conventional oil and gas and coalbed natural gas production the Rock Springs Planning Area for 2012 through 2031.

Table 18. Forecast of annual and cumulative Alternative B conventional oil and gas and coalbed natural gas production the Rock Springs Planning Area for 2012 through 2031.

Table 19. Forecast of annual and cumulative Alternative C conventional oil and gas and coalbed natural gas production the Rock Springs Planning Area for 2012 through 2031.

Table 20. Existing and projected baseline surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area.

Table 21. Existing and projected Alternative A surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area.

Table 22. Existing and projected Alternative B surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area.

Table 23. Existing and projected Alternative C surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area.

INTRODUCTION

The Rock Springs Planning Area (Planning Area) represents the lands managed by the Rock Springs Field Office of the Bureau of Land Management (Bureau) in southwestern Wyoming (Figure 1). The Planning Area includes parts of Sweetwater, Sublette, Fremont, Uinta, and Lincoln counties, Wyoming.

A Resource Management Plan Revision and associated Environmental Impact Statement are currently being prepared for the Planning Area. In support of the Resource Management Plan Revision, this reasonable foreseeable development projection technically analyzes the oil and gas resource known to occur and potentially occurring within the Planning Area and projects future development potential and activity levels for the period 2012 through 2031 (Analysis Period).

The base map used for most map figures in this report is shown in Figure 2. Four areas included on this map are:

1. Wilderness Study Areas, where enclosed lands are legislatively removed from oil and gas leasing.
2. The Union Pacific Railroad Land Grant, where alternating sections of land were conveyed to the Union Pacific Railroad in return for the building of the first transcontinental railway. This area is now in mixed oil and gas mineral ownership (Figure 3) of predominately private lands (on odd-numbered sections), Federal lands (on even-numbered sections), and State lands (generally on sections 16 and 36 of each township).
3. Forest Service lands (Ashley National Forest) surrounding Flaming Gorge Reservoir.
4. The Mechanically Mineable Trona area, where Federal oil and gas mineral lands are presently administratively unavailable for new fluid mineral leasing until the oil and gas resource can be recovered without compromising the safety of underground trona miners. The Resource Management Plan Revision will determine if this area should remain unavailable for new fluid mineral leasing.

Hydrocarbon activities and projections of future development will be discussed separately for coalbed natural gas (see Glossary for coalbed natural gas and natural gas) and for all other types of oil and gas (hereafter known as conventional oil and gas). When both types of hydrocarbon are being referenced, I will hereafter refer to them as oil and gas. Figure 4a presents historic and present conventional oil and gas related development areas for all lands within the Planning Area. Figure 4b presents historic and present coalbed natural gas related development areas for all lands within the Planning Area.

This analysis makes a base line projection that assumes future conventional oil and gas and coalbed natural gas related activity levels on all assessed lands within the Planning Area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 2004). National Forest lands, other Federal agency lands, and State and Private managed lands are included in the base line projection for those lands

assessed for future development. Certain other federally managed lands within the Planning Area are not assessed for the potential for future reasonable foreseeable conventional oil and gas and coalbed natural gas related development. Those lands with legislatively imposed restrictions (no leasing) are not included in this base line projection since activities will not be allowed in the foreseeable future. Those restricted lands only include Bureau managed wilderness study areas (Figure 2).

The reasonable foreseeable development evaluation and projections presented review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential for conventional oil and gas, coalbed natural gas, and deep conventional 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 Planning Area. Additional factors used to project future activities include (but are not limited to) a review of published resource information (including a number of on-line databases) for the area, a call for data from conventional oil and gas and coalbed natural gas operators, a review of petroleum (see Glossary) technology research and development, geophysical activity, and limitations on access and infrastructure. It must be emphasized that the reasonable foreseeable development projections presented are possible and/or likely to happen and should not be considered to be worst-case scenarios, but reasonable and science based projections of the anticipated activity that use logical and technically based assumptions to make those projections (Rocky Mountain Federal Leadership Forum, 2004). Finally, projections of future activity levels for each of three resource management plan alternatives are presented.

The Planning Area contains about 5,358,573 surface acres of all oil and gas mineral ownership types (Figure 3). The Planning Area contains about 3,762,465 acres of Federal oil and gas mineral ownership, or about 70.2 percent of total acres. The remaining 1,596,108 acres (29.8 percent) are managed by state and private interests.

The Bureau manages most of the Federal oil and gas mineral lands in the Planning Area (3,532,962 acres, or about 93.9 percent of the 3,762,465 acres). I assume that all state and private surface lands with Federal minerals are managed by the Bureau and not another Federal agency. All Bureau managed oil and gas mineral lands will be covered by decisions made in the associated Environmental Impact Statement.

The Bureau of Reclamation manages the next largest portion of Federal oil and gas mineral lands within the Planning Area (169,530 acres, or about 4.5 percent of total Federal oil and gas mineral lands). The U.S. Forest Service manages about 51,995 acres, or 1.4 percent and the U.S. Fish & Wildlife Service manages the remaining 7,977 acres (0.2 percent). Lands managed by these other Federal agencies will not be included when decisions are made as part of the Environmental Impact Statement for the Planning Area.

GEOLOGIC OVERVIEW

Most of the Study Area is within the Greater Green River Basin portion of the Wyoming Basin physiographic province, a region of distinct topography and geology. The Greater Green River Basin is a large, complex intermontaine area that covers much of southwestern Wyoming and is bounded by the Wyoming Thrust Belt on the west, the Uinta mountains and Cherokee Ridge to the south; the Sierra Madre, Rawlins Uplift, Granite Mountains, and Wind River Range on the southeast, east, and northeast; and the Gros Ventre Range to the north. The portion of the Planning Area within the Greater Green River Basin predominantly ranges from 6,000 to about 7,500 feet above sea level and is typically an area of treeless plains, mesas, and badlands (Welder, 1968).

The major structural elements of the Planning Area are basins, synclines, arches, uplifts, and anticlines (see Glossary for each type) and are shown in Figure 5a. Within the Greater Green River Basin portion of the Planning Area there are three main sub basins: the Green River, Great Divide, and Washakie basins. The Green River Basin is the largest structural subdivision of the Greater Green River Basin. It includes much of the drainage basin of the present day Green River. The eastern boundary of the Green River Basin is defined by the Rock Springs Uplift (center of Figure 5a) and the southwestern flank of the Wind River Range (northeast portion of Figure 5a). The western boundary of the basin is the Wyoming Thrust Belt, to the west of the Planning Area. The Green River Basin contains three major subareas, with only two within or partly within the Planning Area (Figure 5a). The Bridger Basin is primarily defined by outcrops of lower and middle Eocene (see Glossary) Bridger Formation sediment, and the Moxa Arch is a gentle north-south trending anticlinal feature with two segments shown on the western edge of Figure 5a.

The Great Divide Basin is one of two eastern sub basins within the Greater Green River Basin. It is separated from the Washakie Basin to the south by the east-west trending Wamsutter Arch. The Wamsutter Arch is located just north of Interstate 80 on Figure 5a and runs sub-parallel to it. The basin's western boundary is defined by the Rock Springs Uplift and the northern boundary is defined by the southern flank of the Wind River Range. The eastern boundary lies outside the Planning Area. The Great Divide Basin contains a thick sequence of marine Upper Cretaceous and continental early Tertiary rocks, as well as lacustrine rocks (see Glossary) related to the Eocene Green River Formation. It is also home to the extensive Killpecker dune field, which extends some 90 miles across the basin from east to west. It is the largest continuous area of active sand dunes in the United States.

The Washakie Basin lies south of the Wamsutter arch and east of the Rock Springs Uplift (Figure 5a). Its eastern and southern boundaries lie outside the Planning Area. The basins southwestern edge is marked by several zones of faulting (Washakie Basin fault system of Figure 5b). Like the Great Divide Basin it contains a thick sequence of marine Upper Cretaceous and continental early Tertiary rocks, as well as lacustrine rocks related to the Eocene Green River Formation. The interior of the basin also contains an extensive area of mostly stabilized, but some active, sand dunes.

The Rock Springs Uplift (Figure 5a) is north-south in trend and is tied to the Laramide orogeny (see Glossary). To the west are the Green River and Bridger basins. To the east are the Great Divide and Washakie basins, separated by the Wamsutter Arch, an eastward extension of the Rock Springs Uplift. This uplift is a large asymmetric anticline with its western flank steeper than its eastern flank. The anticlinal axis plunges on both the north and south ends of the structure and a thrust fault (see Glossary) on the western flank (Figure 5b) lies at depth. The uplift is cut by a number of east and northeast trending faults (Rock Springs Uplift fault system of Figure 5b) that displace the sedimentary section by varying amounts. On the northeast flank of the uplift are a number of flat-topped buttes and mesas of volcanic rocks called the Leucite Hills (Figure 5b). These are about one million years old.

Only the southernmost end of the Wind River Range extends into the Planning Area (Figure 5a). It is a large, doubly plunging asymmetrical anticline (Blackstone, 1993) that is bounded in the Planning Area by the Wind River thrust fault (Figure 5b). Blackstone (1993) projected that the Wind River Range uplift occurred from 66 to 53 million years before present (Paleocene to late Eocene time). Lateral tectonic transport on the Wind River thrust fault was 14 miles and vertical separation was 8.9 miles (Blackstone, 1993). Normal faulting in the area (Continental Fault System of Figure 5b) occurred more recently (13.5 million years before present) based on fission-track data (Steidtmann *et al.*, 1989). Six wells appear to have drilled through Precambrian aged rocks and crossed the Wind River thrust fault into younger sediments in the footwall of the thrust (Figure 5b). These wells will be discussed in more detail latter in this report.

A limited amount of Precambrian aged rock is present at the surface in the Planning Area (Figure 5b). All lands northeast of the Wind River thrust fault contain Precambrian aged rocks at the surface or near the surface.

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 Planning Area. Information is presented in the approximate sequence that occurs when project areas or fields (see Glossary) 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 [rotary drilling rigs were not successful in the Rockies until 1927 (Parker and Ray, 2001) when machinery, drill pipe, and bits became tough enough to succeed in drilling the hard rock of this region];
- seismograph (1914), which allowed one dimensional subsurface imaging [seismic was first used in the Rockies in 1928 and the first seismic survey in the Planning Area was probably shot along the southwest flank of the Wind River Mountains in 1936 (Parker and Ray, 2001];
- well logging (1924), which allowed measurement of subsurface rock and fluid properties;
- offshore drilling (1930s), which allowed drillers to access new areas and basins;
- 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 formation's 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 (see Glossary) in the Planning Area. Those major components of accumulations can be:

1. The major structural elements are shown on Figure 5a and the major thrust faults, faults, and selected igneous rocks and Precambrian aged rock outcrops are shown on Figure 5b. The Planning Area lies almost entirely within the Greater Green River Basin, a major intermontane basin of the northern Rocky Mountains, which

occupies southwestern Wyoming and parts of Colorado and Utah. Only the portion of the Wind River Range on the north edge of the Planning Area is not within the Greater Green River Basin. Some features (anticlines and faults) may improve opportunities for the development of oil and gas reservoirs while others (volcanic and Precambrian rocks) may indicate reduced opportunities for the development of reservoirs (at least within those rock types.

2. The Greater Green River Basin contains thick accumulations of sediment. The Precambrian basement defines the depth limit at which sediments can be found. In the Planning Area portion of the Greater Green River Basin, deepest Precambrian basement depths are: Washakie Basin – more than 15,000 feet below sea level or greater than 21,000 feet in depth; Great Divide Basin – more than 20,000 feet below sea level or greater than 27,000 feet in depth; and Green River Basin (in north area) – more than 25,000 feet below sea level or greater than 31,000 feet in depth (Blackstone, 1990). Law (1995) reported that three stages of sedimentation occurred (shelf, foreland, and intrabasinal) to achieve the thick accumulations. "From Middle Cambrian through Middle Jurassic time, the province was located along the eastern edge of the Cordilleran miogeosyncline (Armstrong and Oriel, 1965) and was part of the Rocky Mountain shelf as defined by Peterson (1977). During this sedimentation stage, the province was periodically inundated from west to east by shallow-water seas. The source of siliciclastic sediments was east of the province. In Late Jurassic time, the long period of shelf sedimentation ended and foreland sedimentation was initiated. Siliciclastic sediments, previously derived from the east, began to be derived from the west. Emerging highlands in eastern Idaho and central Utah became the principal sources of clastic sediments." The intrabasinal sedimentation stage began at the end of Cretaceous time and is marked by the development of discrete foreland uplifts and adjacent basins. "During this stage, sediments derived from local uplifts were deposited in adjacent basins, which in many areas restricted depositional patterns to specific basins" (Law, 1995).
3. Mesozoic and Tertiary aged sandstones and shales (potential source and reservoir rocks) exist, with thick and thin coals present under most of the Greater Green River Basin. Carbonate rocks (potential reservoir rocks) are predominant in older formations (formations of Paleozoic age) within the basin. Figure 6 presents a stratigraphic chart for the Planning Area showing nomenclature used for these accumulations in this report. Figure 6 also shows the predominate oil and gas producing zones within the Planning Area. Figure 7 shows all oil and gas fields located within the Planning Area (DeBruin, 2012). These fields help define areas were there has been the greatest historical interest in exploring for and developing the conventional oil and gas resource within the Planning Area.
4. Burial and thermal histories that could promote the development and preservation of diagenetic pore-throat traps (see Glossary) and extensive oil and gas generation in the center of the Green River, Great Divide, and Washakie basins.
5. Structure traps (see Glossary), have played a role in localizing oil and gas accumulations within the Planning Area. During the earliest phases of exploration these types of traps were the target.

6. Stratigraphic traps (see Glossary), which have had a large role in exploration and development within the Planning Area in more recent times, especially when coupled with stratigraphic variation.
7. Pressure regimes, ranging from slightly under-pressured to highly over-pressured, could be important in the center of the Green River, Great Divide, and Washakie basins. In areas of abnormally high pressures, productive capacity can be greatly increased. Over-pressuring also creates problems in drilling and completion, increasing the cost of both.
8. Secondary porosity, produced by the dissolution of unstable grains (see Glossary) and rock fragments, is important in local accumulations.

I believe that these components are also important in exploring for and developing new oil and gas resources in the Planning Area. Most recent (January 1, 2002 to April 2012) Planning Area conventional oil and gas exploratory and development drilling activity (Figure 8a) has been occurring in and around existing fields (Figure 7), with only about 15 percent of new wells spudded (See Glossary for spudded) as wildcats (see Glossary for wildcat wells). During this same time period Planning Area coalbed natural gas activity has been occurring within existing developed areas in the east, with only about 11 percent consisting of scattered wells drilled from Range 102 and westward (Figure 8b). Near term projected activity, as indicated by active drilling permits of operators (Figure 8c), shows that most new conventional oil and gas wells are planned in localized areas in the northwest, northeast, and southeast parts of the Planning Area. Only a small number of wells are planned outside these three areas. Figure 8c also shows that only a small number of coalbed natural gas wells are planned in the near term and these permitted wells are located near the northeast border of the Planning Area.

Potential unconventional gas resources (see nonconventional gas in Glossary) make up a portion of hydrocarbon resource that will be explored for and developed in the Planning Area in the future. Unconventional gas is a potentially large resource, although it is technically challenging to develop. Three types of unconventional gas have potential for future development within the Planning Area.

1. Tight Sands Gas – formed in sandstone or carbonate (called tight gas sands) with low permeability, which prevents the gas from naturally flowing to a borehole (See Glossary).
2. Coalbed Natural Gas – formed in coal deposits and adsorbed (see Glossary) by coal particles.
3. Shale Gas – formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and microfractures. In the Planning Area these potential resources may occur in the Hilliard, Baxter, and Mancos Shales. The Niobrara Formation has also been identified as a potential shale gas resource in the Planning Area. It is time equivalent to the lower portions of the Hilliard, Baxter, and Mancos Shales.

Hunt (2012) reported that “in 2011, unconventional gas market share reached 34 percent of all U.S. natural gas production. By 2035 it is expected to be 60 percent of all U.S.

natural gas production." The tight sands gas and shale gas types of reservoirs have a lower drilling, completion, and operating risk, lower finding costs, and lower reserve decline rates. Technological advances needed to produce these types of reservoirs have been in:

- Reservoir knowledge
- Hydrofracing
- Stimulation
- Horizontal drilling
- Drilling fluids
- Three-dimensional seismic.

Commonly these types of unconventional gas resources have lower reserves (see Glossary) per well and many wells are required to develop the resource. There is a need for well cost and environmental footprint control when developing these resources.

EXPLORATORATION AND DEVELOPMENT ACTIVITY – 2002 TO 2012

Conventional Oil and Gas Activity

Of the 939 conventional oil and gas boreholes (see Glossary), including directional and horizontal boreholes, spudded (see Glossary) from January 1, 2002 to April 2012 initial classifications, as defined by IHS Energy Group (2012) were:

• Core Hole	1 borehole	0.11 percent
• Development	731 boreholes	77.85 percent
• Development Redrill	2 boreholes	0.21 percent
• Injection	54 boreholes	5.75 percent
• Injection-Gas	1 borehole	0.11 percent
• Injection-Water	2 boreholes	0.21 percent
• Pilot	1 borehole	0.11 percent
• Stratigraphic Test	2 boreholes	0.21 percent
• Unclassified	8 boreholes	0.85 percent
• Deeper Pool Wildcat	6 borehole	0.64 percent
• New Field Wildcat	101 boreholes	10.76 percent
• New Field Wildcat-Redrill	1 boreholes	0.11 percent
• Wildcat Outpost	29 boreholes	3.09 percent

Locations of these boreholes are shown in Figure 8a. Total wildcats, core holes, pilots, and stratigraphic tests (See Glossary for stratigraphic test) were 148, or 15.76 percent of the total. Of the 939 boreholes drilled, 22 (2.34 percent) were deepened or redrilled.

Of the 939 conventional oil and gas boreholes drilled from January 1, 2002 to April 2012 over 61 percent were drilled in five fields (Figure 7):

• Jonah	193 boreholes
• Patrick Draw	189 boreholes
• Fontenelle	67 boreholes

- Trail 65 boreholes
- Canyon Creek 64 boreholes

In an additional nine fields operators drilled 10 to 23 boreholes during this period. These boreholes accounted for over 16 percent of the total:

- Point of Rocks 23 boreholes
- Table Rock 22 boreholes
- Blue Forest 21 boreholes
- Lincoln Road 18 boreholes
- Little Monument 17 boreholes
- Mesa 14 boreholes
- Desert Springs 14 boreholes
- Baxter Basin 13 boreholes
- LaBarge/LaBarge East 10 boreholes

All other fields contained fewer than 10 boreholes, or the boreholes were not drilled within named fields.

Of the 741 conventional oil and gas development wells (see Glossary) completed (excluding 60 spudded development wells that are not completed) during this period, their final classification (IHS Energy Group, 2012) ended up as:

- Abandoned 40 boreholes
- Gas 517 boreholes
- Oil 98 boreholes
- Injection 73 boreholes
- Service 12 boreholes
- Pilot 1 borehole

Of the development boreholes completed, 94.6 percent were successful.

Of the 132 conventional oil and gas wildcats completed (including one core hole and excluding six spudded wells that are not completed) during this period, final wildcat classifications (IHS Energy Group, 2012) ended up as:

- Drilled and Abandoned 38 boreholes
- Oil 1 borehole
- Gas 93 boreholes

Of the wildcat boreholes completed, about 71 percent were successful.

Of the 939 conventional oil and gas boreholes spudded from January 1, 2002 to April 2012 there were only 55 total operators that drilled at least one well (IHS Energy Group, 2012). The top four operators were:

- Anadarko Exploration and Production Company 202 boreholes
- Encana Oil and Gas (USA) Incorporated 148 boreholes
- Wexpro Company 134 boreholes
- Cabot Oil and Gas Corporation 61 boreholes

These four companies were responsible for 58 percent of the 939 boreholes.

Eleven operators drilled between 10 and 40 boreholes during the period. They were:

- BP America Production Company 37 boreholes
- XTO Energy, Incorporated 36 boreholes
- McMurry Oil Company 35 boreholes
- GMT Exploration Company LLC 31 boreholes
- Whiting Oil and Gas 30 boreholes
- Yates Petroleum Corporation 22 boreholes
- EOG Resources, Incorporated 19 boreholes
- Samson Resources Company 18 boreholes
- Burlington Resources O&G Company LP 17 boreholes
- Chevron USA, Incorporated 14 boreholes
- QEP Energy Company 13 boreholes

These 11 companies were responsible for 29 percent of the 945 boreholes. The remaining 13 percent of the boreholes were drilled by 40 operators who drilled fewer than 10 boreholes each. Seventeen of the 40 operators only drilled one wellbore.

New conventional oil and gas productive completions have come from 16 formations and the Mesaverde Group (which includes four individual formations), from January 1, 2002 to April 2012 (IHS Energy Group, 2012). See Figure 6 for the locations of the formations and the Mesaverde Group relative to each other in time that are listed below. From oldest to youngest those formations are:

- Pennsylvanian – Weber Sandstone 11 boreholes
- Permian – Phosphoria Formation 2 boreholes
- Jurassic – Nugget Sandstone 1 borehole
- Jurassic – Morrison Formation 3 boreholes
- Lower Cretaceous – Dakota Sandstone 21 boreholes
- Lower Cretaceous – Bear River Formation 2 boreholes
- Lower Cretaceous – Muddy Sandstone 3 boreholes
- Upper Cretaceous – Frontier Formation 221 boreholes
- Upper Cretaceous – Baxter Shale 40 boreholes
- Upper Cretaceous – Blair Formation 2 boreholes
- Upper Cretaceous – Rock Springs Formation 7 boreholes
- Upper Cretaceous – Ericson Sandstone 6 boreholes
- Upper Cretaceous – Almond Formation 145 boreholes
- Upper Cretaceous – Mesaverde Group 118 boreholes
- Upper Cretaceous – Lewis Shale 38 boreholes
- Upper Cretaceous – Lance Formation 180 boreholes
- Tertiary – Fort Union Formation 1 borehole

For the period analyzed, 801 different productive completions have been made. Some boreholes have had as many as four different formations completed for production. Of the 709 boreholes completed as productive only 70 were completed in at least two formations (IIS Energy Group, 2012).

The Mesaverde Group (which includes the Almond Formation, Ericson Sandstone, Rock Springs Formation, and Blair Formation) was completed in 39 percent of the 709 boreholes. Most of these boreholes were in Patrick Draw, Trail, and Canyon Creek fields in the southeast part of the Planning Area (Figure 7). The Frontier Formation was completed in 31 percent of the 709 boreholes. Most of these boreholes were in Fontenelle, Blue Forest, Mesa, Little Monument, Lincoln Road, and LaBarge/East LaBarge fields in the northwest part of the Planning area or Canyon Creek, Trail, and Point of Rocks fields in the southeast (Figure 7). The Lance Formation was completed in more than 26 percent of the 709 boreholes. These boreholes were almost entirely in the Jonah Field area (Figure 7). The Baxter shale was completed in 5.6 percent of the boreholes which are predominantly located in Canyon Creek, Trail, and Fontenelle fields (Figure 7). The Lewis Shales was completed in almost 5.4 percent of the boreholes which are predominantly located in Desert Springs and Laney Wash fields (Figure 7). The remaining eight formations account for the remaining 6.2 percent of productive wells and a scattered across the Planning Area.

True vertical drilling depths for 915 conventional oil and gas boreholes, with recorded depths, drilled from January 1, 2002 to April 2012 have ranged from 42 to 18, 524 feet (IHS Energy Group, 2012). Depth ranges, number of boreholes in each range, and percent of the total are:

- Less than 5,000 feet 136 boreholes 14.86 percent
- 5,000 to 10,000 feet 397 boreholes 43.39 percent
- 10,000 to 15,000 feet 371 boreholes 40.55 percent
- Greater than 15,000 feet 11 boreholes 1.20 percent

The deepest well was development well in Table Rock Field (Figure 7) drilled near the eastern boundary of the Planning Area in section 3 of township 18 north, range 98 west. Three gas producing completions were made in this well in the Upper Cretaceous Baxter Shale, Permian Phosphoria Formation, and Pennsylvanian Weber Sandstone (Figure 6). Of these 11 boreholes, 10 were completed as gas producers and one is waiting on completion. Nine boreholes are located within Table Rock Field and eight are completed in the Pennsylvanian Weber Sandstone through perforations deeper than 15,000 feet. Nine boreholes were drilled as vertical and two were directional.

Of the 371 conventional oil and gas wells drilled to depths between 10,000 and 15,000 feet their status types were:

- Gas 321 boreholes
- Oil 3 boreholes
- Spudded 17 boreholes
- Injection 2 boreholes
- Temporarily Abandoned 2 boreholes
- Pilot 1 wellbore
- Drilled and Abandoned 25 boreholes

The predominant producing zones in this depth range were:

- Lance Formation 170 boreholes
- Frontier Formation 81 boreholes
- Mesaverde Group 63 boreholes

Boreholes were completed as directional (132 boreholes or 35.58 percent), horizontal (14 boreholes or 3.77 percent), and vertical (225 boreholes or 60.65 percent).

Of the 397 boreholes drilled to depths between 5,000 and 10,000 feet their status types were:

- Gas 245 boreholes
- Oil 59 boreholes
- Spudded 22 boreholes
- Injection 45 boreholes
- Service 5 boreholes
- Temporarily Abandoned 5 boreholes
- Drilled and Abandoned 16 boreholes

The predominant producing zones in this depth range were the Mesaverde Group with 149 boreholes and the Frontier with 131 boreholes. The oldest producing formation in this depth range was the Jurassic Morrison Formation. Boreholes were completed as directional (133 boreholes or 33.5 percent), horizontal (11 boreholes or 2.77 percent), and vertical (153 boreholes or 38.54 percent).

Of the 136 boreholes drilled to depths of less than 5,000 feet their status types were:

- Gas 33 boreholes
- Oil 37 boreholes
- Spudded 2 boreholes
- Injection 27 boreholes
- Service 6 boreholes
- Observation 1 borehole
- Temporarily Abandoned 7 boreholes
- Drilled and Abandoned 23 boreholes

The predominant producing zone in this depth range is the Mesaverde Group with 57 boreholes. The oldest producing formation in this depth range was the Jurassic Morrison Formation. Boreholes were completed as directional (4 boreholes or 2.9 percent), horizontal (0 boreholes), and vertical (132 boreholes or 97.1 percent).

Coalbed Natural Gas Activity

Of the 105 coalbed natural gas boreholes spudded from January 1, 2002 to April 2012 initial classifications, as defined by IHS Energy Group (2012) were:

- Development 76 boreholes 72.38 percent
- Development Recompletion 1 borehole 0.95 percent
- New Field Wildcat 21 boreholes 20.01 percent
- Wildcat Outpost 7 boreholes 6.67 percent

Locations of these boreholes are shown in Figure 8b. Total wildcats were 28, or 26.67 percent of the total and total development boreholes were 77, or 73.33.

Of the 105 coalbed natural gas boreholes drilled from January 1, 2002 to April 2012 over 78 (74.29 percent) were drilled in the southeast part of the Planning Area, 18 (17.14 percent in the northeast part, and the remaining nine (8.57 percent) were scattered across the Planning area (Figure 8b).

Of the 105 coalbed natural gas wells completed during this period, their final classification (IHS Energy Group, 2012 and Wyoming Oil and Gas Conservation Commission, 2012) ended up as:

- Abandoned 3 boreholes
- Gas 99 boreholes
- Injection 1 borehole
- Temporarily Abandoned 2 boreholes

The success rate of coalbed natural gas wells for this period was 95 percent.

Of the 105 coalbed natural gas boreholes spudded from January 1, 2002 to April 2012 there were 12 total operators that drilled at least one well (IHS Energy Group, 2012). The top six operators were:

- Warren Exploration and Production, Incorporated 31 boreholes
- Anadarko Petroleum Corporation 20 boreholes
- Infinity Oil & Gas of Wyoming (defunct) 18 boreholes
- Kennedy Oil Company, Incorporated 13 boreholes
- Yates Petroleum Corporation 7 boreholes
- RME Petroleum Company 4 boreholes

These six companies were responsible for 89 percent of the 105 boreholes. Half of the remaining six operators each drilled two boreholes and the other half drilled only one borehole each.

New coalbed natural gas productive completions have come from a limited number of formations, from January 1, 2002 to April 2012 (IHS Energy Group, 2012 and Wyoming Oil and Gas Conservation Commission, 2012). In 62 boreholes, coals in only the Almond Formation (Figure 6) were completed. The Mesaverde Group (which contains the Almond Formation) was completed in coals in 13 boreholes. Coals in the Fort Union were completed in 23 boreholes. One borehole also was reported to be completed in coals in the Lance Formation as well as in coals of the Almond Formation.

True vertical drilling depths for 105 coalbed natural gas boreholes, drilled from January 1, 2002 to April 2012 have ranged from 200 to 12,258 feet (IHS Energy Group, 2012 and Wyoming Oil and Gas Conservation Commission, 2012). Depth ranges, number of boreholes in each range, and percent of the total are:

- Less than 5,000 feet 80 boreholes 76.19 percent
- 5,000 to 10,000 feet 24 boreholes 22.86 percent
- 10,000 to 15,000 feet 1 borehole 0.95 percent

The shallowest perforated coal producing zone is 868 feet and the deepest is almost 6,000 feet. All but one well was drilled vertically. One horizontal well was drilled and it has produced from Almond Formation coal.

EXPLORATORATION AND DEVELOPMENT SUCCESS

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 also be produced. Improvements have also allowed down-spacing to occur in some cases. Increased drilling success rates have cut the number of both wells drilled and dry holes (U.S. Department of Energy, 1999). The Energy Information Administration (2007) has projected the increase in percentage of wells drilled successfully will be 0.2 percent per year to 2030.

From the mid 1970's to the present, oil and gas activity in the Planning Area has been focused on drilling lower risk development wells in and around already producing fields (Table 1). Since 1974, development wells have exceeded wildcat wells drilled for all years with the exception of the years 1976 and 1978. In addition, 27 percent of the wildcat wells [outpost, deeper pool, shallower pool, and new pool (see Glossary for each type)] could be considered to be drilled in and around already producing fields. The remaining 73 percent of these wildcat wells [new field wildcats (see Glossary)] were drilled far from producing fields. Most townships saw the drilling of at least one wildcat well during this 42 year period. Sixty-one townships, with at least some portion lying in the Planning Area, saw no wildcat drilling. Most of these townships were in and around National Forest lands and on the north-central part of the Planning Area. Forty-one townships saw the drilling of only one wildcat well. Most of these townships were also in and around the National Forest lands and trended slightly northeast to the northernmost part of the Planning Area. The remaining 167 townships occupy the eastern, northwestern, and southwestern parts of the Planning Area.

Exploration Activity and Success

Wildcat wells (Figure 9a) were drilled at an average rate of 42 per year from 1970 through 1982 (Table 1). High average drilling rates appear to have been at least partly tied to relatively high gas prices in the early 1980s in a region that is predominantly gas producing. More than 70 percent of these wells were drilled east of the town of Rock Springs, with over 21 percent drilled in the northwest part of the Planning Area and less than nine percent drilled in the southwest.

The wildcat drilling rate dropped considerably in 1983 and from then through 1996 the rate averaged only 10 wells per year. This was a period when oil prices were low nationally and gas prices began to drop from a high point in the early 1980s. Almost 45 percent were drilled in the northwest part of the Planning Area and about 39 percent were drilled east of Rock Springs, with 16 percent scattered across the Planning Area.

There was a rebound to an average of 19 wells per year between 1997 and 2008. This marks a period of increases for gas prices over most of the period and a rebound in oil prices that began in 2000. About 27 percent of these wells were drilled south of Interstate 80 and east of Range 101 West, 23 percent were drilled in the northwest part of the Planning Area, and over 12 percent were drilled in the area just west of the eastern arm of Forest Service lands, with the remaining 38 percent scattered across the area.

During the most recent three years only five wildcat wells were drilled. This drilling reduction corresponds to a drop in gas prices that has occurred nationally in a part of southwest Wyoming where most exploratory targets are gas rich.

During the 1970 through 2011 time period, wildcat wells (Figure 9b) were only 34 percent successful from 1970 through 1982 (Table 1). This was also a period of high wildcat well drilling rates, as previously discussed. During this time period wells were most successful (69 percent success) along the northwest border of the Planning Area and along the southwest border (73 percent). There were scattered successful wells in the rest of the Planning Area for this period, but at 34 percent or less.

For a short period (1983 through 1987) success rates increased to an average of 70 percent although drilling rates had dropped to 8.6 wells per year (Table 1). Wildcat wells were most successful in the same areas identified as most successful for the 1970 through 1982 period (Figure 9b), but at an even higher success rate (84 percent successful in the two areas combined). Just over 74 percent of wells drilled were located in these areas. The remaining 26 percent of wells only had a 27 percent success rate, which was in line with the precious 1970 through 1982 period for the same parts of the Planning Area.

For the 1988 through 1997 period success rates dropped to an average of 41 percent (Table 1). A larger part of the northwest portion of the Planning Area (the area north of Interstate 80 and west of State Highway 191) had better success rates during this period. Success rates were 57 percent and 41 percent of wells drilled between 1988 and 1997 were drilled in this area (Figure 9b). Over the rest of the Planning Area the success rate was 30 percent, which was about the same as the two previous periods.

For the 1998 through 2008 period success rates increased significantly to 75 percent. Success rates in the northwest portion of the Planning Area increased to 83 percent for about 22 percent of the 206 wildcat wells drilled (Table 1). Two additional wells saw high success rates. In the southeast (townships 12 to 18 north, and ranges 95 to 100 west) wells were drilled at an 82 percent success rate for 28 percent of the 206 wells drilled (Figure 9b). An 82 percent success rate was also established for the wells drilled just southwest of the town of Green River. These wells were drilled almost entirely by Saurus Resources, Incorporated; and they all have since been abandoned with almost no production. Success rates for the rest of the Planning Area during this period were 61 percent for the remaining 36 percent of wildcat wells drilled. The success rates for the rest of the Planning Area was still about double over what it was during the previous three analysis periods described.

Additional future exploratory drilling will be required to discover new resources in the Planning Area. Since the risk of failure is higher for these types of activities, future success rates could decline slightly from the 75 percent rate attained from 1998 through 2008.

Development Activity and Success

Development wells (Figure 9c) were drilled at an average rate of 31 per year from 1970 through 1973 (Table 1). More than 91 percent of these wells were drilled south of township 22 north and east of U.S. Highway 191. Almost all the remaining wells were drilled along the northwestern border of the Planning Area.

The development drilling rate increased considerably for 1974 through 1983 and averaged 56 wells per year (Table 1). As for the previous exploration drilling rate discussion, high average drilling rates during this period appear to have been at least partly tied to relatively high gas prices in the early 1980s in a region that is predominantly gas producing. Drilling rates south of township 21 north and east of U.S. Highway 191 remained at about that of the 1970 through 1973 period and accounted for about 51 percent of wells drilled (Figure 9c). Development drilling increased in other parts of the Planning Area. Along the northwestern border of the Planning Area drilling activity was about 31 percent of the total during the 1974 through 1983 period. North of township 20 north and east of U.S. Highway 191 about 16 percent of total wells were drilled. In addition, a few development wells were drilled along the southwest border of the Planning Area.

Development drilling dropped to an average of about 34 wells per year from 1984 through 1991 (Table 1). As with the previous exploratory drilling discussion, this was a period when oil prices were low nationally and gas prices began to drop from a high point in the early 1980s. Most areas previously discussed had reduced development drilling activity. Drilling rates south of township 21 north and east of U.S. Highway 191 dropped by about 75 percent from the previous time period and accounted for about 22 percent of total wells drilled (Figure 9c). Along the northwestern border of the Planning Area drilling activity drilling activity dropped by about 27 percent and increased to about 47 percent of the total for the eight year period. North of township 20 north and east of U.S. Highway 191 development drilling activity dropped by about 30 percent to about 24 percent of total wells were drilled. Along the southwest border of the Planning Area a few additional were drilled, but they remained at a small percentage of wells drilled (six percent).

From 1992 through 2011 development drilling doubled to an average of 68 wells per year (Table 1). As with the previous exploratory drilling discussion, this period saw increased gas prices and a rebound in oil prices that began in 2000. During this period drilling increased in two of the four areas previously discussed and decreased in the other two areas. In addition, new development drilling occurred in three parts of the Planning Area. Average drilling rates south of township 21 north and east of U.S. Highway 191 increased by about 310.1 percent from the previous time period and accounted for about

31 percent of total wells drilled (Figure 9c). Along the northwestern border of the Planning Area drilling activity drilling activity increased by about 470 percent and increased to about 43 percent of the total for the twenty year period. North of township 20 north and east of U.S. Highway 191 development drilling activity dropped by about 50 percent to about 5 percent of total wells drilled for the period. Along the southwest border of the Planning Area only five additional development wells were drilled, and the percentage of the total dropped to less than on half percent. In the Jonah Field Area (Figure 9c) new development accounted for about 17 percent of development wells drilled for the period. In the area of the Stagecoach Draw Field (Figure 9c) more than two percent of the new wells were drilled and in the area developed by Saurus Resources, Incorporated slightly less than two percent of new wells were drilled. As previously stated, the Saurus wells have almost entirely been abandoned with almost no production reported.

During the 1970 through 2011 time period, development wells (Figure 9d) were 58 percent successful from 1970 through 1973 (Table 1). During this time period wells were most successful (60 percent success) south of township 21 north and east of U.S. Highway 191 (Figure 9d). North of township 20 north and east of U.S. Highway 191 the success rate was about 54 percent of total wells drilled and the rate was only about 33 percent for the limited number of development wells drilled along the northwest border.

For the 1974 through 1981 period development well success rates increased to an average of 68 percent (Table 1). During this time period wells south of township 21 north and east of U.S. Highway 191 (Figure 9d) were slightly more successful (64 percent) than during the previous time period. North of township 20 north and east of U.S. Highway 191 the success rate was about 56 percent of total wells drilled (again, only a slight improvement). The biggest improvement was along the northwest border where it improved to 92 percent. Infill development drilling accounts for the significant improvement in success rates in this area. Only a few wells were drilled along the southwestern border, with a 60 percent success rate.

For the 1982 through 1991 period success rates increased significantly to an average of 86 percent (Table 1). Almost half the wells drilled during this time period were along the northwest border of the Planning Area (Figure 9d) and the success rate was the highest (97 percent) in this area. Wells south of township 21 north and east of U.S. Highway 191 also increased from the previous period (from 64 to 78 percent successful). North of township 20 north and east of U.S. Highway 191 the success rate was increased from about 56 percent successful to 77 percent successful. The success rate also improved along the southwestern border (from 60 percent to 71 percent), although this area had the lowest success rate.

For the 1992 through 2008 period success rates increased again to 94 percent overall for 1,365 wells. About 31 percent were drilled south of township 21 north and east of U.S. Highway 191 and the success rate for this area dropped to 92 percent from 97 percent in the previous period. The largest numbers of these wells were drilled in the Canyon Creek Dome, Trail, and Monell units (Figure 10) including 72 injection wells in the Monell

unit. The success rate along the northwestern border remained at 97 percent and accounted for about 43 percent of all wells drilled during the period. North of township 20 north and east of U.S. Highway 191 the success rate was increased from about 77 percent successful to 85 percent successful with fewer wells drilled than during the previous period. Along the southwestern border only five new development wells were drilled with a success rate declining to 60 percent. Development drilling occurred in three new areas in the 1992 through 2011 period. About 17 percent of wells were drilled in the Jonah Field Area (Figure 9d) and they were 97 percent successful. In the Stagecoach Draw Field area new wells were 81 percent successful and in the Saurus Resources, Incorporated development area south of the town of Green River they were 85 percent successful. Again, most of these wells have been since abandoned with almost no production.

Additional future development drilling will be required to discover additional resources in the Planning Area. Since many existing fields have had high rates of infill development drilling since 1970, additional development activities will need to include drilling in and around new fields that have yet to be discovered. Future success rates are expected to decline from the high of 94 percent attained from 1998 through 2011.

TECHNOLOGY AND COST

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 (see Glossary), and reservoirs
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions

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 on-shore 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. 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. For the 2006 to 2008 period costs more than doubled to 24.61 dollars per barrel. These increases were in part a result of the high prices of oil and natural gas that existed through that period. Prices dropped by 24.2 percent for the 2007 to 2009 period and averaged 18.65 dollars per barrel. Producers have reduced spending to find oil and gas reserves since gas prices had declined during this period. Oil prices have again risen since 2009 so producers can be expected to be increasing their spending to find new oil reserves.

Once hydrocarbons have been found, acquired, and developed for production the expense 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, 2007). Lifting costs again increased, to 15.24 dollars per barrel, by 2008 (Energy Information Administration, 2011a) and then dropped by 29.9 percent in 2009. Lifting costs declined in 2009 mostly due to a fall in production taxes, which was tied to a decline in oil and natural gas prices.

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. No development contracts presently lie within the Planning Area. The Bureau has a record of four historical development contracts that have terminated (Figure 11).

The Vermillion development contract was operated by Marathon Oil Company with White Energy Corporation as a partner. It was established May, 1, 1996 to explore the Nugget Sandstone over about 2,100,000 acres in the Planning Area, on lands to the east of the Planning Area, and to the south in Colorado. Lands in the contract area lying within the Table Rock, Higgins, Brady, and Hiawatha Deep units (Figure 10) were not included. The contract terminated May 1, 2003.

The Bridger Basin development contract was operated by Encana Oil & Gas (USA), Incorporated with Energy West Corporation as a partner. It was established January 1, 2003 to primarily explore the Ericson Formation over about 178,845 acres in the Planning Area and to the north. The Wilderness Study Areas within the contract area were excluded from the contract (Figure 11). The contract terminated January 1, 2004.

The Tabernacle Butte development contract was operated by Occidental Oil & Gas Corporation with Encana Oil & Gas (USA), Incorporated as a partner. It was established August 1, 2005 to explore the Lance Formation beneath the Wind River Thrust over about 146,000 acres in the Planning Area and a small area to the north. The contract terminated August 1, 2007.

The Greens Canyon development contract was operated by Anadarko Exploration and Production Company LP with Kestrel Energy, Incorporated as a partner. It was established May 1, 2004 to explore the Nugget and Weber sandstones and the Madison Limestone over about 463,370 acres in the Planning Area. The contract terminated May 1, 2008.

Finally, Anadarko Exploration and Production Company LP proposed the South Pass development contract which was denied by the Bureau in March of 2005.

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.

A need to conserve oil and gas resources in the United States was identified early in the 20th century and was reinforced by national security issues surrounding the importance of petroleum in fighting the First World War (Avery and Miller, 1934). Congress in 1930 enacted temporary legislation providing for participation in unit operations or cooperative development among lessees of public lands (46 Stat. 1007). The first unit approval (January 6, 1931) in the United States was of the Little Buffalo Basin gas unit in the Bighorn Basin of Wyoming. Northern Hiawatha unit (Table 2) was the first Planning Area unit approved (November 1, 1936). One well was completed under the unit agreement, testing oil and gas in the Wasatch Formation. The unit was terminated in 1954. In the following years thousands of units have been created in the United States. Many are still active while others have terminated.

Conventional Oil and Gas Unit Agreements

Within the Planning Area 493 units have been approved or proposed. Of these units, there are presently only 63 that are still active (Figure 10). Table 3a shows who the unit operator is for these active units as well as their effective date, their present type, original size when established, whether they have been contracted to a smaller area, and the present size of each unit. Figure 10 shows the present limits of each active unit. Table 3b indicates townships and ranges that each unit laid in at its maximum size and what the initial test well requirements were. These units originally covered 1,172,244.86 acres (not all parts were located within the Planning Area), but have been reduced in size to 569,765.73 acres. About 441,660 acres are located within the Planning Area and cover about 8.2 percent of all lands.

Sixty-one started as exploratory units, but only 10 are still in an exploratory drilling phase (Table 3a). Exploratory units are initially approved as exploration tools to investigate non-producing parts of the Planning Area. These units cover 236,869.79 acres or about 41.57 percent of the area of the 63 units. Exploration will continue in these units as long as wells are successful. If the operator cannot successfully develop a unit it will terminate. If wells are successful, the unit will generally contract to the area of successfully drilled wells after five years.

Of the 51 units that started as exploratory unit types there are 47 units that now predominately produce gas within the Planning Area (Table 3a). These units have contracted to the area of successful wells. They contain about 280,816.9 acres or about 49.29 percent of the area of the 63 units. The remaining four units produce predominately oil, contain 34,128.94 acres and account for about 5.99 percent of the area of the 63 units. Development drilling is continuing in some of these gas and oil units, while others are concentrating on obtaining maximum recovery with existing wells.

The remaining two units are 17,950.08 acres in size an account for only 3.15 percent of the area of the 63 units. The lands encompassed by these two units (Monell and Henry Enchanced) were already oil productive and they were unitized to allow for secondary recovery operations to occur in a logical manner. Operators of these two units are working to obtain maximum oil recovery. Secondary oil recovery will be discussed in more detail later in this report.

Twenty-three companies operate the 63 units within the Planning Area. Wexpro Company operates nine units and Breitburn Operating, LP operates six units (Table 3a and 3b). Three companies operate four units, six operate three units, six operate two units, and six companies operate only one unit.

There are an additional 429 units that are known to have been approved or proposed in the Planning Area in the almost 76 years since the first Planning Area unit approval (Table 2). Most units (339 units or 79.02 percent) have terminated. The remaining units were withdrawn or cancelled before final approval (78 units or 18.18 percent), declared

invalid (11units or 2.56 percent) because the operator did not meet its drilling obligation, and one unit was denied.

The Planning Area covers 5,358,573 acres. The 429 units covered more than 9,295,493 acres (unit acres were not available for seven units). The same lands in many parts of the Planning Area have been unitized a number of times, thus accounting for the total acreage exceeding total acres within the Planning Area. There are only 17 townships (Figure 10) were a unit has never been approved or proposed.

There are 160 operators responsible for the 429 approved or proposed units within the Planning Area. Operators responsible for 10 or more units are:

- Davis Oil Company 40 units
- Yates Petroleum Corporation 24 units
- Mountain Fuel Supply Company 24 units
- Union Pacific Resources Company 17 units
- Anadarko E&P Company, LP; Anadarko Petroleum Corp.; and Anadarko Production Company 14 units

Ten operators were responsible for six to nine units each, 45 were responsible for two to five units each, and 100 operators have had only one of the 429 units approved or proposed.

Figure 12 shows the number of active and closed units approved by year (withdrawn, cancelled, and denied units were assumed to be proposed in the same year they were closed). This chart mirrors well drilling activity that has historically occurred within the Planning Area (Figure 13).

IHS Energy Group (2012) data show only 77 wells drilled in the 36 years prior to the first unit forming in 1936 (Figures 13 and 14a). Most wells were located on the elongate north-south Rock Springs Uplift (Figure 5a) and discoveries produced natural gas. From the first unit in 1936 through 1948 unitization was rarely used. Only 11 units were approved or proposed during this 13-year period, but five of the 11 units are still active (Tables 3a and 3b and Figure 10). During the subject time period 54 wells were spudded (Figure 14b) at a rate of almost five wells per year. Early production was primarily associated with the development of structural traps along the Rock Springs Uplift and in the southeast part of the Planning Area. Production was primarily natural gas with a few wells producing oil.

From 1949 through 1957 unit activity increased to 33 new units for an average of almost four new units per year. Only three of the 33 new units are still active (Tables 3a and 3b and Figure 10). Drilling rates also increased during this nine year period to 101 wells spudded (Figure 14c), or about 11 new wells per year. Average annual drilling rates more than doubled during this period. Many wells continued to be located along the Rock Springs Uplift with more widespread drilling in the southeast. A few gas wells were productive on the northwest edge of the Planning Area. Again, most wells

predominately produced natural gas. Crude oil prices were relatively high during the subject period.

The first large increase in unitization activity (and in drilling activity) occurred from 1958 through 1963 when 67 units were approved or proposed for an average of 11 per year or about three times the previous level. This increase in activity appears to have been tied to a significant period of discovery and development of some of the largest fields within the Planning Area. This activity occurred despite a gradual decline in crude oil prices that was occurring over the same period. Nine of the units approved between 1958 through 1963 are still active (Tables 3a and 3b and Figure 10). During this same six-year period there was also the first large increase in drilling activity levels and 566 wells were spudded (Figure 14d) for an average of 94 per year. Average annual drilling rates increased by about 8.5 times over the previous time period. Drilling was more widespread with many wells being oil productive in the east and gas continuing to be explored for and developed in the southeast and northeast. Fewer wells were being drilled on the Rock Springs Uplift.

Unit and drilling activity dropped during the next nine year period (1964 through1972). During this nine year period 39 units were approved or proposed, with an average of just over four units per year. Four of the units approved between 1964 and 1972 are still active (Tables 3a and 3b and Figure 10). Drilling rates also dropped during this period. There were 503 wells spudded (Figure 14e) for an average of about 56 wells per year, for an average yearly reduction in activity of about 40 percent. Natural gas wells and oil wells were about equally drilled during this period. Productive wells continued to be drilled along the Rock Springs Uplift, to the southeast, to the northwest, and one gas well was completed on the southern end of the Moxa Arch (Figure 5a) in the southwest. These drops in unit and drilling activity occurred during a period of continued slow declines in crude oil prices.

The next period of increased unit activity was from 1973 through 1981 (Figure 12). During this period 138 units were approved or proposed, with an average of just over 15 units per year. Fourteen of the units approved between 1973 through 1981 are still active (Tables 3a and 3b and Figure 10). Unit activity increased by about 3.5 times the previous period discussed. Drilling rates also increased substantially during this period, but stayed high for an additional two years (through 1983). From 1973 through 1983 spudded wells jumped to 1,053 (Figure 14f), with an average spud rate of almost 96 well per year (a rate slightly higher than that of the 1958 through 1963 period). Drilling occurred in and around the four areas discussed in the previous time period, but at higher drilling rates. Natural gas completions were more common than oil completions. The 1973 through 1981 period corresponds to a period of high crude oil prices that began with the oil embargo of 1973. After 1981 oil prices began to decline, eventually dropping back to pre-1973 prices for many years. Gas prices had mirrored those of oil prices for most of this period, but continued to be elevated into the mid 1980's probably accounting for continued higher drilling interest in the Planning Area through 1983.

From 1981 through 2011 yearly unitization rates have fluctuated between zero and 12 units approved or proposed in any year (Figure 12). The average rate has been about six new units per year. Twenty-eight of the 188 units approved or proposed since 1981 are still active (Tables 3a and 3b and Figure 10). For 1984 through 2011 operators have spudded 2,054 wells with an average of 73 new spuds per year (an approximately 24 percent yearly decline in drilling from the previous period). Rates of unitization and well drilling have been somewhat reflected in gas prices during this period which have been variable. Most drilling during this period has concentrated on infill drilling (See Glossary for infill drilling) locations and in step-out drilling from existing production.

Coalbed Natural Gas Unit Agreements

Within the Planning Area 16 units have been approved or proposed (Figure 15). Of these units, there is presently only one unit that is still active. Table 4 shows who the unit operator is for all 16 units as well as the effective date, final status, closed date, townships and ranges the units are located in, and what the initial test well requirements were for each unit. When approved, total unit area was 316,408.59 acres. Three units contracted to a smaller size:

- Chicken Springs contracted to 2,391.07 acres
- North Cooper Ridge contracted to 2,999.74 acres
- Copper Ridge contracted to 3,584.41 acres

Their initial and contracted boundaries are shown on Figure 15. About 294,325.54 acres were located within the Planning Area and these lands covered about 5.5 percent of all Planning Area lands. As previously stated, only the 2,391.07 acre contracted Chicken Springs unit is still active.

Present status of the 16 coalbed natural gas units is:

- one active unit
- six terminated units
- four units declared invalid, ab initio due to the operator did not meet its drilling obligation
- five units cancelled or withdrawn

All 16 units started as exploratory unit proposals. Coalbed natural gas wells have only been drilled on nine of the 16 units. Chicken Springs unit and the six now terminated units (Figure 15 and Table 4) met at least their initial well drilling requirements. At the Azurite unit only two of the five required wells were drilled and at Maravich unit only one of the required five was drilled.

The oldest coalbed natural gas unit proposals were the West Wind, East Wind, and Wind Break units (Figure 15), which were all cancelled in July of 1992 (Table 4). The first unit approved that had a well drilled within its boundary was Greasewood Wash. Most coalbed natural gas wells drilled within the Planning Area have been located within coalbed natural gas units (Figure 15). Seventy-seven of the 136 wells drilled (56.6 percent) are located within units.

Only 11 of the 136 total coalbed natural gas wells drilled were drilled within the Planning Area (Figure 16) prior to the first unit (Greasewood Wash) approved in 1999 (Table 4). Only four of the 11 wells were completed as productive and those four were drilled in the area that would become Greasewood Wash unit.

In the year 2000 there were six wells drilled (Figure 16) and all were completed as producing wells in Greasewood Wash unit (Figure 15). In 2001 Infinity Oil & Gas of Wyoming (now defunct) completed 12 of the 14 wells drilled in townships 18 and 19 north, range 100 west. Eleven wells were completed as productive and one was abandoned. Texaco Exploration and Production drilled and abandoned a well in township 23 north, range 98 west. Stephens Energy drilled the fourteenth coalbed natural gas test in township 29 north, range 107 west and completed it as a service well.

In the year 2002 there were 21 wells drilled (Figure 16), with five in Copper Ridge, two in Rifes Rim, and one in Pacific Isle units (Figure 15). Infinity Oil & Gas of Wyoming completed an additional 12 coalbed natural gas wells in townships 18 and 19 north, range 100 west and Kennedy Oil Company, Incorporated completed a successful well in township 23 north, range 98 west.

The greatest number of coalbed natural gas well tests was completed in 2003 (Figure 16). Most of the 42 wells drilled were in units. There were 11 more wells drilled at Copper, eight more at Pacific Isle, the first five at North Copper, and one well at Rifes Rim (Figure 15). Of the remaining 17 wells drilled Infinity Oil & Gas of Wyoming completed an additional six coalbed natural gas wells in townships 18 and 19 north, range 100 west; Kennedy Oil Company, Incorporated completed 10 more wells in township 23 north, range 98 west; and Anadarko Exploration and Production Company drilled and abandoned a well in township 14 north, range 114 west.

In 2004 coalbed natural gas well drilling dropped to 17 wells (Figure 16). Of the 13 unit wells drilled there were six additional wells at Pacific Isle, four more at Rifes Rim, two more at North Copper, plus the first well at Chicken Springs (Figure 15). Of the remaining four wells drilled Kennedy Oil Company, Incorporated completed a producer in township 25 north, range 97 west; Yates Petroleum Corporation completed a producer on the west edge of township 18 north, range 99 west; Kerr-McGee Oil & Gas drilled and abandoned a well in township 25 north, range 102 west; and EOG Resources, Incorporated drilled and abandoned a well in township 25 north, range 105 west.

In 2005 there were 14 coalbed natural gas wells drilled (Figure 16). Of the eight wells drilled in units there were three more drilled in Chicken Springs, one more in Rifes Rim, the first two wells in Azurite (one was abandoned and the other completed as an injection well), the first well in Hi-Line, and the first well in Maravich (Figure 15). Of the remaining six wells drilled Kennedy Oil Company, Incorporated completed an additional well in township 24 north, range 98 west; Kestrel Energy, Incorporated completed the second well to be abandoned in township 20 north, range 105 west; XTO Energy, Incorporated completed a well in township 22 north, range 106 west and one in township

24 north, range 108 west; and SWEPI LTD Partnership completed a well in township 23 north, range 106 west and one in township 25 north, range 106 west.

The 2006 year was the last year that coalbed natural gas wells were drilled in the Planning Area (Figure 16). There were 11 wells drilled, all within units. Four additional wells were drilled in Rifes Rim, four more were drilled in Hi-Line, and three more were drilled in Chicken Springs.

There are currently still three permits to drill new wells that are proposed by Summit Gas Resources, Incorporated. Two permits are located in township 24 north, range 98 west and one is located in township 25 north, range 97 west (Figure 4b).

Six companies operated the 16 coalbed natural gas units within the Planning Area (Table 4). Yates Petroleum Corporation proposed six units and only met its drilling commitment in the Hi-Line unit. At Hi-Line unit production reported from six coalbed natural gas wells was 131,435 barrels of water and no gas (Wyoming Oil and Gas Conservation Commission, 2012). Yates also drilled an initial well in the Maravich unit, but chose not to drill the remaining four required wells. The well did not produce.

Arco Oil and Gas Company proposed three units and cancelled them without drilling. Three units were also proposed by Warren E&P, Incorporated. They drilled on all three of their units, with one still active and two terminated. Rifes Rim unit produced 39.29 million cubic feet of gas from 11 wells drilled, with only 247 barrels of water reported. All wells have been abandoned or proposed for abandonment. Pacific Isle unit produced 62.29 million cubic feet of gas and 3,100,155 barrels of water from 15 wells drilled (Wyoming Oil and Gas Conservation Commission, 2012). One well produced 379 barrels of oil. All wells have been abandoned. The active Chicken Springs unit has produced 1.22 billion cubic feet of gas, 667 barrels of oil, and 22,994 barrels of water from seven wells (Wyoming Oil and Gas Conservation Commission, 2012).

Anadarko Petroleum Corporation drilled on two coalbed natural gas units that have been terminated in the past year. At their North Copper Ridge unit they produced 848.77 million cubic feet of gas and 23,000 barrels of water from five wells (Wyoming Oil and Gas Conservation Commission, 2012). A notice of intent to abandon has been filed on four of these wells and a subsequent report of abandonment has been filed on the fifth well. At their Copper Ridge unit they produced 612.49 million cubic feet of gas and about 1.83 million barrels of water from 16 wells (Wyoming Oil and Gas Conservation Commission, 2012). Two wells produced 3,825 barrels of oil. Of the 16 wells four are abandoned, a subsequent report of abandonment has been submitted for seven, and a notice of intent to abandon has been submitted for the remaining five.

Barrett Resources Corporation drilled on one coalbed natural gas unit. They recovered 56.64 million cubic feet of gas, 349,692 barrels of water, and 1,081 barrels of oil from six wells (Wyoming Oil and Gas Conservation Commission, 2012). A notice of intent to abandon has been submitted for all six wells. El Paso Production Oil & Gas Company proposed the final coalbed natural gas unit, but did not drill any wells.

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 Wyoming, 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 (See Glossary for spacing pattern) established by State or Bureau 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 nonunit land.

Conventional Oil and Gas Communitization Agreements

At present, 164 active conventional oil and gas communitization agreements lie within the Rock Springs Planning Area (Figure 17). These agreements cover an area of about 44,166 acres (1.2 percent of the Planning Area). The agreements have a variety of acreage:

- 10 acres – 4 agreements
- 40 acres – 1 agreement
- 80 acres – 6 agreements
- 160 acres – 93 agreements
- 320 acres – 32 agreements
- 640 acres – 23 agreements
- 700 acres or larger – 5 agreements

Other communitization agreements have been approved in all decades since the first Planning Area agreement made effective in January of 1964. Numbers of still active agreements by decade are:

- 1960s – 6
- 1970s – 10
- 1980s – 55
- 1990s – 44
- 2000s – 49.

Most of these agreements were initiated in the 1980s, 1990s, and the 2000s. The forming of the communitization agreements as occurred at a fairly even pace over the last three decades.

Communitization agreements have been established, and are still active, in 11 different productive zones. They are:

- Lance Formation – 6 agreements
- Lewis Shale – 6 agreements
- Almond Formation – 4 agreements
- Mesaverde Group – 4 agreements
- Baxter Shale – 4 agreements
- Frontier Formation – 96 agreements
- Mowry Shale – 1 agreement
- Muddy Sandstone – 2 agreements
- Dakota Formation – 22 agreements
- Bear River Sandstone – 17 agreements
- Multiple formations – 2 agreements

Twenty-six companies operate the 164 communitization agreements. Operators with more than five agreements are:

- Cabot Oil & Gas Corp. 35 agreements
- Crown Energy Partners, LLC 20 agreements
- Samson Resources Co. & Chevron USA, Inc. 15 agreements each
- EOG Resources, Inc. 13 agreements
- Whiting Oil & Gas Corp. 11 agreements
- XTO Energy, Inc. 10 agreements
- Yates Petroleum Corp. 8 agreements

Two companies each operate five agreements, four operate three agreements each, three operate two agreements each, and nine companies only operate one agreement.

Coalbed Natural Gas Communitization Agreements

At present, only one active coalbed natural gas communitization agreement lies within the Planning Area (Figure 17). This agreement covers an area of about 160 acres. Infinity Oil & Gas operates this agreement which was effective in 2001.

TYPICAL DRILLING AND COMPLETION SEQUENCE

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the Wyoming Oil and Gas Conservation Commission http://wogcc.state.wy.us/. If the well will be located on Federal 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 Planning 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 (many horizontal well completions do not contain casing in the horizontal part of the borehole);
- 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 Planning Area could be:

- access to some well sites can be more difficult when they are remote from the main activity areas and when they are located in steep terrain,
- harsh environments (particularly cold temperatures),
- changes in rig availability,
- changes in development priority as industry focus on certain plays evolves with new discoveries and changes in oil and gas price,
- labor market conditions, and
- restrictions (many of them environmental restrictions of some type) on land use.

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
- 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 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 FOR CONVENTIONAL OIL AND GAS

The existence of oil in Wyoming has been known for centuries. Earliest interest in the southwest Wyoming was west of the Planning Area in Uinta County. The first account was an 1848 report of an oil seepage at what became known as Brigham Young oil spring (Espach and Nichols, 1941). Oil was skimmed from this spring and nearby springs and from pits dug near them. The oil was used for lubrication and medicinal purposes. No oil and gas wells are known to have been drilled until 1900 (IHS Energy Group, 2012). Although some shows of hydrocarbons were made in some of the early wells drilled the first discovery was not made until South Baxter Basin field was discovered in 1922 (Reese, 1968). Early exploration and development activities (through 1963 are discussed below). Coalbed natural gas exploration activity has previously been discussed in the unitization discussion.

Early Exploration and Development Activity – 1900 through 1935

Information on exploration and development of the conventional oil and gas fields within the Planning Area is available from Nightingale (1930 and 1935), Espach and Nichols (1941), Biggs and Espach (1960), Ritzma (1963), Reese (1968), Wyoming Geological Association (1950, 1955, 1957, 1961, 1962, 1965, and 1979, and 1992), and Bureau files.

There were probably a number of tests drilled before 1900 that are not recorded in the IHS Energy Group (2012) and Wyoming Oil and Gas Conservation Commission (2012) data bases. Andrews (1965) reported that the earliest well drilled in 1872 was shallow and drilled by Union Pacific Railroad in section 35 of township 19 north, range 105 west. It found coal and was used to supply water. He also reported that “Two wells were drilled in 1873. One, in sec. 27, T. 20 N., R 101 W., near Point of Rocks, was drilled to 1,000 feet and found a trace of oil at 351 feet, with 37 feet of petroliferous shale just below. The other, in sec. 10, T. 18 N., R. 99 W., went to a depth of 696 feet in the Tertiary with no reported shows.

Wells drilled in the Planning Area just after the turn of the century were located along the Rock Springs Uplift (Figure 5a). Between 1900 and the first well discovery in the Planning Area, Andrews (1965) reports:

> "In 1900 the Belgo-American Petroleum Company drilled several wells in the vicinity of Baxter Station." (Baxter Station is in section 23 of township 19 north, range 104 west) "Several small companies drilled eight to ten wells south of Baxter Station. None were on the crest of the anticline, and most were less than 1,000 feet deep. One well went to 2,300 feet and recovered a small trace of oil and gas. Around 1900, a well was drilled to 2,400 feet in sec. 17, T. 18 N., R. 103 W., and some oil was recovered at 625 feet. In 1901 a second Union Pacific well at Point of Rocks went to 1,002 feet, and in 1910 a third well there went to 1,009 feet. The early Union Pacific wells were drilled to assess the coal strata and to provide water for the steam engines. In 1915 and 1916, six wells were drilled in the southern part of T. 18 N., R. 103 W., in sections 16, 18, 19, 20, and 30 to depths ranging from 1,000 feet to 2,744 feet. (American Oil Company drilled two wells in section 18; Midwest Oil Company, one well in section 20; and Dry Lake Oil Company, two wells in sections 16 and 20.) In sec. 16, T. 18 N., R. 103 W. shows of gas were encountered at 200 feet and at 651 feet from stray Baxter sands, and shows of oil at 2050, 2160, and 2235 feet from Frontier sands. "

Some of the above discussed wells are shown on Figure 14a but many are not. Figure 14a shows wells IHS Energy Group (2012) has a record of being drilled between 1900 and 1935. They show that 12 wells were drilled from 1900 through 1921 (Figure 13) while Andrews (1965) discussion indicates that there were probably additional wells drilled. Almost all 77 wells shown were drilled in the vicinity of the Rock Springs Uplift.

As discussed by Biggs and Espach (1960), Andrews (1965), and shown by IHS Energy Group Data (2012) some early wells along the southern part of the Rock Springs Uplift had indications of gas and oil when drilled. The first commercially productive well in this area, (and in the Planning Area) was drilled by The Ohio Oil Company, now Marathon Oil Company (Andrews, 1965) in section 16 of township 16 north, range 104 west. Surface mapping had indicated a structural closure that could trap hydrocarbons at this location (Reese, 1968). Faulting also has had an effect on the gas accumulation in this trap (Figure 5b). The discovery well was completed in 1922 and it produced sour gas (a small amount of hydrogen sulfide gas was associated with the hydrocarbon gas) at a rate of 36 million cubic feet per day from the Dakota Sandstone. The well was located on the Rock Springs Uplift and the associated field was subsequently named Baxter Basin South (Figure 14a). The presence of hydrogen sulfide caused the deaths of a number of people in the early days of development of this field. Continued drilling and development of Baxter Basin South field caused the discovery of gas in the Frontier Formation in 1924. Of the 77 wells drilled during this period 40 wells (52 percent) were drilled in and around the Baxter Basin South field (IHS Energy Group, 2012). Twenty-two of the 40 wells were completed as gas wells. Additional information on the early history of this field can be found at Nightingale, (1935; Espach and Nichols, 1941; Fidlar, 1950 and 1962; Wyoming Geological Association, 1957; and Reese (1968).

Discovery of Baxter Basin South field lead to the surface mapping and testing of another anticlinal structure to the north and a commercial discovery well was completed in 1926 at what became Baxter Basin North field (Figure 14a). Faulting (Figure 5b) also had an effect on this trap. The discovery was made in section 11 of township 19 north, range 104 west. The discovery well was found to be gas productive in the Dakota Sandstone (14 million cubic feet per day) with a show of gas in the Frontier Formation (six million cubic feet per day). Commercial gas production was found in the field in the Morrison Formation in 1929 at a rate of 3.8 million cubic feet per day. Sour gas, with some oil was found in the Nugget Sandstone in 1945 at a rate of 12.7 million cubic feet per day. In 1962 Mountain Fuel Supply Company drilled a test into granite in section 11 of township 19 north, range 104 west and discovered nonflammable gas (high percentages of carbon dioxide gas) in the Weber Sandstone and Madison Limestone. Of the 77 wells drilled during this period eight wells (10 percent) were drilled in and around the Baxter Basin North field (IHS Energy Group, 2012). Five of the eight wells were completed as gas wells.

The third and final field to be discovered in the Planning Area in the 1900 through 1935 period was Hiawatha gas field (Figure 14a). Some papers indicate that the discovery of this field was made in October 1926 (Espach and Nichols, 1941; and Biggs and Espach, 1960), while others indicate the field was discovered in February 1927 (Nightingale, 1930; Gras, 1955; and Wyoming Geological Association, 1957). The discovery well was located in Colorado and produced gas from the Wasatch Formation. The field was shut in until 1929 when a pipeline was installed to carry gas to Rock Springs and beyond. Gas was also discovered in the Fort Union Formation in 1929 (Wyoming Geological Association, 1979 and 1992). Hydrocarbon shows were present in the Lewis Shale, Mesaverde Group, Baxter Shale, Frontier Formation, Dakota Sandstone, and Nugget Sandstone. Of the three Hiawatha Field wells drilled within the Planning Area two were completed as gas wells. Hiawatha Field lies on a small local anticline known as Hiawatha Dome (Nightingale, 1930).

Of the remaining 26 wells drilled during the 1900 through 1935 period there were 13 wells drilled and abandoned between Baxter Basin South and Baxter Basin North fields (Figure 14a). This area will be discussed in the next section. The other 13 wells were scattered around the Planning Area. None were oil or gas productive

Exploration and Development Activity – 1936 through 1948

From 1936 through 1948 operators drilled 54 additional exploration and development wells in the Planning Area and three new fields were discovered (Figure 14b). Additional drilled wells and the status of these new wells in the three existing fields was:

- Baxter Basin South 10 gas and 2 abandoned
- Baxter Basin North 7 gas and oil, 1 service, and 3 abandoned
- Hiawatha 4 gas

In 1938 Baxter Basin Middle field was discovered. The successes at north and south Baxter Basin fields and surface mapping led to the discovery of this field (Reese, 1968). Drilling activity in this field dates back to as early as 1915 (see previous section discussion). Most wells of the earlier period were drilled primarily to test for oil and there were gas flows in some tests, but all these early wells were abandoned (Reese, 1968). Baxter Basin Middle field lies on the crest of the Rock Spring Uplift (Figure 5a) between the previously discovered south and north Baxter Basin fields (Figure 14b). The trap is modified by numerous faults (Figure 5b). The discovery well obtained 2.2 million cubic feet of gas per day from the Frontier Formation. In 1939 gas was discovered in the Dakota Sandstone at 3.5 million cubic feet of gas per day. Twelve wells were drilled in and around the field during the subject period. Seven wells were completed as gas producers and five wells were abandoned.

Canyon Creek field (Figure 14b) was the next field to be discovered. The Canyon Creek anticline was mapped as early as 1928 and the first test on this structure was made in 1929 (Bureau Files). It was then abandoned. Westates Petroleum Corporation drilled the discovery well in the Fort Union Formation in 1941, but it did not produce to a pipeline and it was later abandoned (Wyoming Geological Association, 1979). Ericson Sandstone gas was discovered in 1954, Almond Formation gas was discovered in 1972, and Lance Formation oil and gas was discovered in 1975 (Wyoming Geological Association, 1979). Hydrocarbon shows were present in the Dakota and Nugget sandstones. In addition to the discovery well, one other well was drilled and abandoned in 1943.

The final discovery for the 1936 through 1948 period was what would become the large Table Rock field (Mees, *et al.*, 1961; Ritzma, 1963; White, 1965; Wyoming Geological Association, 1979 and 1992; Dickinson, 2001; and Bureau files, 2012). The field lies on the east flank of the Rock Springs Uplift and northwest edge of the Washakie Basin along what is known as the Wamsutter Arch (Figure 5a). Surface closure of the anticline at Table Rock indicated the potential for trapped hydrocarbons. Prior to 1946 The Texas Company did some seismic work that indicated the large anticline in the subsurface (Cox, 1962). Shallow gas was discovered in March of 1946 in what was called the Wasatch Formation (more likely the Fort Union Formation) at a rate of 3.5 million cubic feet per day. This well marked the first production found in this part of the Planning Area and its completion eventually lead to a drilling boom. Additional drilling found small amounts of gas and oil (Ritzma, 1963) but the shallow sands were discontinuous and production was small. In 1954 a deeper test discovered gas in sandstone of the Lewis Shale at 5.68 million cubic feet per day and in the Almond Formation at 8.98 million cubic feet per day (Mees, *et al.*, 1961). Nugget Sandstone gas was discovered in 1965, Madison Limestone gas was discovered in 1975, Weber Sandstone gas was discovered in 1976, and Dakota Sandstone gas was discovered in 1977. In 1991, Texaco and Union Pacific Resources discovered overpressured gas in the Frontier Formation on the northern end of the Table Rock Field (Dickinson, 2001). A number of horizontal wellbores were drilled in an attempt to improve production from the Frontier Formation. Hydrocarbon shows were present in the Ericson Sandstone, Rock Springs Formation, and Dakota Sandstone. During the 1936 through 1948 period two gas wells were drilled and a third was drilled but abandoned.

Of the remaining 10 wells drilled all but one are reported as abandoned (Figure 14b). A well that tested 100 barrels of oil from the Wasatch Formation was completed in 1942, but there are no production records.

Exploration and Development Activity – 1949 through 1957

From 1949 through 1957 operators expanded their drilling activity to 101 additional exploration and development wells in the Planning Area and doubled the number of new fields discovered by adding six new fields (Figure 14c). Only one of the new fields was destined to become very large. Additional drilled wells and the status of these new wells in and around the six existing fields was:

- Baxter Basin South 1 abandoned
- Baxter Basin North 5 gas and 2 abandoned
- Hiawatha 8 gas, 1 water injection, and 1 abandoned
- Baxter Basin Middle No wells
- Canyon Creek 5 gas, 1water injection, and 1 abandoned
- Table Rock 5 gas and oil and 1 abandoned

Salt Wells Field is a small anticline that was discovered in November of 1949 (Biggs and Espach, 1960). Surface geological mapping led to the drilling and subsequent discovery (Reese, 1968) of this field which lies on the southeast flank of the Rock Springs Uplift. The discovery was made in the Dakota Sandstone, and initial production was 13.8 million cubic feet of gas per day. A discovery in the Frontier Formation was added in 1952. Hydrocarbon shows were present in the Blair Formation. Three gas wells were completed and two additional wells were drilled and abandoned from 1949 through 1957.

Middle Mountain Field (Figure 14c) is a small anticlinal structure discovered in 1952 (Olson, 1955; Biggs and Espach; and Wyoming Geological Association, 1957 and 1979). Oil and gas production (169 barrels of oil, 1.156 million cubic feet of gas, and two barrels of water) was from the Mesaverde (Almond Formation and Ericson Sandstone). Hydrocarbon shows were present in the Fort Union Formation, Frontier Formation, Dakota Sandstone, Entrada Sandstone, Nugget Sandstone, and Phosphoria Formation. Three oil and gas wells and two abandoned wells were completed from 1949 through 1957.

Southwest Table Rock Field (Figure 14c) was discovered in 1955 with the drilling of one well (White, 1955; Wyoming Geological Association, 1957 and 1979; and Biggs and Espach, 1960). A previous well had been drilled and abandoned in the same section as the discovery well (section 28 of township 18 north, range 98 west) but had only drilled to the Wasatch Formation (Figure 14b). The discovery well tested the Mesaverde at 981,000 cubic feet per day. No other wells were completed in the field from 1949 through 1957.

The Chimney Rock Field discovery was made in 1956. The first well was completed as a gas producer in the Blair Formation (Wyoming Geological Association, 1979) at a rate of

3.69 million cubic feet per day. Hydrocarbon shows were present in the Frontier Formation, Dakota Sandstone, and Nugget Sandstone. Two other wells were drilled and abandoned in the vicinity in 1956. The field was abandoned in 1974 (Wyoming Oil and Gas Conservation Commission, 2012).

Twin Rocks Field (Figure 14c) was discovered in 1956 with a completion in the Frontier Formation at a rate of 887,000 cubic feet per day. The reservoir is located in a structural-stratigraphic type trap (Wyoming Geological Association, 1979). Gas in the Morrison Formation was discovered in 1972 at a rate of 1.22 million cubic feet per day. Hydrocarbon shows were present in the Dakota Sandstone.

LaBarge East Field was discovered in early 1957 (Wyoming Geological Association, 1979). This stratigraphic and structural trap was first productive in the Frontier Formation at a rate of 4.307 million cubic feet of gas per day. Oil was discovered in the Fort Union in 1963 and gas was discovered in the Mesaverde Group in 1964. Two of the six well drilled in this time period were completed as gas productive. A third well was first drilled and abandoned, but re-entered and completed as a gas well in 1973. The remaining three wells were drilled and abandoned.

Little Worm Creek Field was discovered in 1957. The faulted structure was located by surface mapping (Reese, 1968) and seismic and the trap is considered to be a combination of stratigraphic and structural components (Wyoming Geological Association, 1957, 1979, and 1992). In the discovery well the Morrison Formation tested oil and the Dakota Sandstone tested gas, but the well was completed only in the Morrison. Later wells were completed in the Dakota Sandstone. Hydrocarbon shows were present in the Frontier Formation. Only the discovery well was drilled in the 1949 through 1957 period.

During the 1949 through 1957 period, 43 additional wells were drilled outside existing and new fields. Most of these wells were drilled and abandoned and most had shows of gas and/or oil when drilled (IHS Energy Group, 2012). In 1952 a gas well was completed in township 12 north, range 100 west (Figure 14c). Sandstone in the Baxter Shale tested gas at three million cubic feet per day but it would not produce after production tubing was run so it was subsequently plugged and abandoned (Reese, 1968). The well was located in what would become the Trail Unit Field, which was discovered in 1958 (Figure 14d).

The gas well located in township 21 north, range 98 west (Figure 14c) was spudded in 1957 but was not completed until 1958. It became the discovery well for the Desert Springs Field (Figure 14d). The gas well located in township 23 north, range 102 west (Figure 14c) was drilled and abandoned in 1949, but was later re-entered and completed as a gas well that did not begin producing until 1965. The well became part of the Nitchie Gulch Field (Figure 14d).

Exploration and Development Activity – 1958 through 1963

A large increase in drilling activity from 1958 through 1963 (Figure 13) resulting in the discovery of 19 new fields (Figure 14d), some very large. Of the 565 wells spudded during this period 318 wells (56.28 percent) were drilled in and around new fields, only 47 wells (8.32 percent) were drilled in and around some of the already existing fields, and 200 wells (35.40 percent) were drilled outside all fields.

1958

In 1958 four fields were discovered. Trail Field (Wyoming Geological Association, 1957 and 1979) is an anticlinal trap located in the southeast part of the Planning Area (Figure 14d). Gas was discovered in both the Ericson Sandstone and Rock Springs Formation. Hydrocarbon shows were present in the Wasatch and Almond formations.

The Playa Field (Wyoming Geological Association, 1979 and 1992) is located in the east-central part of the Planning Area (Figure 14d) along the Wamsutter Arch (Figure 5a). Gas was discovered in a stratigraphic trap in the Lewis Shale at Playa Field. Hydrocarbon shows were present in the Almond Formation. The field eventually grew and became a part of the Patrick Draw/Desert Springs field complex.

Joyce Creek (Figure 14d), on the southern end of the Rock Springs Uplift (Figure 5a) was initially an oil discovery on a Dakota Sandstone stratigraphic trap (Wyoming Geological Association, 1979). A gas discovery was made in 1960 at Joyce Creek on a faulted anticlinal nose. Hydrocarbon shows were present in the Nugget Sandstone, Entrada Sandstone, Phosphoria Formation, and Weber Sandstone.

The fourth, and largest of the fields discovered in 1958, was Desert Springs (May, 1961; Cox, 1962, Ritzma, 1963; Weimer, 1965 and 1966; Wyoming Geological Association, 1961, 1972, 1979, and 1992; and Ryder *et al.*, 1981). The field is located in townships 19, 20, and 21 north, range 98 west (Figure 14d). It was the first purely stratigraphic trap from the Mesaverde Group in the Planning Area (May, 1961). It led to the discovery of Patrick Draw oil field and West Desert Springs oil and gas field the next year and all were eventually combined into the Patrick Draw/Desert Springs field complex. The initial gas discovery was made in the Almond Formation and Lewis Shale gas production was added a few months later. Hydrocarbon shows were present in the Fox Hills Sandstone.

Wells drilled in and around the four fields in the Planning Area and their status in the 1958 through 1963 period were:

- Trail 9 gas wells and 6 abandoned wells
- Playa 1 gas well and 3 abandoned wells
- Joyce Creek 4 oil and gas wells and 2 abandoned wells
- Desert Springs 17 gas wells and 5 abandoned wells

1959

In 1959 five additional fields were discovered in the Planning Area. Kinney (Wyoming Geological Association, 1979) was discovered in the southeast part of the Planning Area (Figure 14d). A gas discovery on a structural/stratigraphic trap was made in the Almond Formation. Gas discoveries were added in the Wasatch Formation in 1965 and in the Frontier Formation in 1977. Hydrocarbon shows were present in the Lance Formation.

Just east of the previously discovered East LaBarge Field (Figure 14c), the Green River Bluffs discovery (Figure 14d) found gas in the Lance Formation from a stratigraphic trap (Wyoming Geological Association, 1979). No other wells were drilled in the field area and the field was abandoned in 1967. Hydrocarbon shows were present in the Mesaverde Group.

Black Butte Creek (Figure 14d) is located on the east flank of the Rock Springs Uplift (Figure 5a). A gas discovery was made in a stratigraphic trap in the Frontier Formation (Wyoming Geological Association, 1979). An additional gas discovery was made in the Morrison Formation in 1960 and a gas discovery in the Dakota Sandstone was made in 1965. Hydrocarbon shows were present in the Baxter Shale.

The remaining two fields are located on the Wamsutter Arch (Figure 5a) and each eventually became part of the large Patrick Draw/Desert Springs field complex. Desert Springs West (Figure 14d) was discovered when gas production from the Almond Formation was found (Weimer, 1965 and 1966; and Wyoming Geological Association, 1959 and 1961, 1979, and 1992) in a stratigraphic trap. Hydrocarbon shows were present in the Lewis Shale.

Three units (Arch, Beacon Ridge, and Patrick Draw) were formed adjacent to each other and discoveries in the Almond Formation were made in each unit in 1959. They all became part of the Patrick Draw Field (Burton, 1961; Lawson and Crowson, 1961; Cox, 1962; Weimer, 1966; McCubbin and Brady, 1969; and Wyoming Geological Association, 1959 and 1961, and 1979) as drilling progressed. The trap is considered to be stratigraphic. Hydrocarbon shows were present in the Fox Hills Sandstone, Lewis Shale, and Ericson Sandstone.

Wells drilled in and around the five fields in the Planning Area and their status for the 1958 through 1963 period were:

- Kinney 2 gas and 2 abandoned
- Green River Bluffs 1 gas and 1 abandoned
- Black Butte Creek 2 gas and 4 abandoned
- Desert Springs West 23 oil and gas and 6 abandoned
- Patrick Draw 173 oil and gas and 17 abandoned

1960 and 1961

Only one new field (Sand Butte Field) was discovered, in 1960 (Figure 14d). The Almond Formation was gas productive from the Almond Formation in a stratigraphic trap (Wyoming Geological Association, 1979). Hydrocarbon shows were present in the Ericson Sandstone. One gas well and two abandoned wells were drilled in and around the Sand Butte Field from 1958 through 1963.

1962

In 1962 eight additional fields were discovered in the Planning Area. Three of the eight fields are located along the Rock Springs Uplift (Figure 5b). Pretty Water Creek near the south end (Figure 14d). Gas production was discovered in a stratigraphic trap (updip pinchout). The Frontier Formation was the only producer (Wyoming Geological Association, 1979) although the Dakota Sandstone, Morrison Formation, and Phosphoria Formation had hydrocarbon shows. Some carbon dioxide gas is reported as being present in the field (Becker and Lynds, 2012).

Six Mile Springs is located on the west limb of the Rock Springs Uplift (Figures 5a and 14d). Gas was discovered in a stratigraphic trap in the Frontier Formation (Wyoming Geological Association, 1979 and 1992). Hydrocarbon shows were found in the Dakota Sandstone.

Nitchie Gulch is the largest field discovered in 1962. It is located on the northern end of the Rock Springs Uplift (Figures 5a and 14d). The discovery well was originally drilled in 1949 (Figure 14c) that was re-entered in 1962 and completed in the Dakota Sandstone and Frontier Formation in a stratigraphic trap (Reese, 1968; and Wyoming Geological Association, 1972, 1979, and 1992). Hydrocarbon shows were present in the Rock Springs Formation and Baxter Shale sections.

The Massacre Hills Field oil discovery (Figure 14d) was made in a stratigraphic trap in the Rock Springs Formation (Wyoming Geologic Formation, 1979). The Almond Formation had a hydrocarbon show. Massacre Hills Field was abandoned in 1963 (Wyoming Oil and Gas Conservation Commission, 2012).

The Ten Mile Draw Field is located on the Wamsutter Arch (Figures 5a and 14d). The Lewis Shale was found to be gas productive in a stratigraphic trap (Wyoming Geological Association, 1979). Gas was discovered in the Almond Formation in 1972.

At Red Hill Field (Figure 14d), a sandstone at the base of the Lance Formation was found to be oil productive (Weimer, 1965). The field was abandoned in 1973 (Wyoming Oil and Gas Conservation Commission, 2012).

Hallville Field is a stratigraphic trap productive in the Almond Formation. The discovery well produced oil (Wyoming Geological Association, 1979).

The final discovery of 1962 was in the Bitter Creek Field (Figure 14d). It was a gas discovery in the Lance Formation (Wyoming Geological Association, 1979), but it and subsequent Lance wells were shut-in and never produced. Almond Formation gas was discovered in 1976. Formations with hydrocarbon shows were the Blair Formation and Ericson and Nugget sandstones. Recent research (Norris and Phillips, 2002) indicates that the field is a basin centered, over pressured, tight gas sandstone reservoir located across the top and flanks of an anticline.

Wells and their status for each of the eight fields in the Planning Area in the 1958 through 1963 period were:

- Pretty Water Creek 1 gas well
- Six Mile Springs 1 gas well and 3 abandoned wells
- Nitchie Gulch 4 gas wells and 1 abandoned well
- Massacre Hill 1 oil well and 1 abandoned well
- Ten Mile Draw 1 gas well
- Red Hill 2 oil and gas wells and 3 abandoned wells
- Bitter Creek 2 gas wells

1963

The final field discovery in the 1958 through 1963 period was Point of Rocks Field (Wyoming Geological Association, 1979). Gas was discovered in the Blair Formation in a stratigraphic trap (Figure 14d). Gas in the Frontier Formation was discovered in 1973. Hydrocarbon shows were found in the Muddy Sandstone. One gas well and four abandoned wells were drilled in and around the field from 1958 through 1963.

Other wells

Drilling in and around fields discovered prior to 1958 was limited to 47 wells. Sixteen of the 47 were abandoned and the rest were completed as productive or service. Only three fields (East LaBarge, Canyon Creek, and Table Rock) had any significant drilling activity (Figure 14c). Wells and status of completions by field was:

- East LaBarge 17 gas and oil, and 6 abandoned
- Canyon Creek 6 gas
- Table Rock 3 gas and oil, 1 service, and 3 abandoned
- Little Worm Creek 1 oil and 4 abandoned
- Baxter Basin North 1 gas and 1 abandoned
- Baxter Basin South 1 gas and 1 abandoned
- Salt Wells 1 abandoned
- Table Rock Southwest 1 abandoned

Of the 200 wells drilled outside of oil and gas fields, all but eight were immediately abandoned (Figure 14d). One well was hooked up as a service well for water (section 13, of township 23 north, range 110 west) and was later abandoned. One was spudded in 1963 but completed as a gas well in 1964 (section 32 of township 23 north, range 103

west) and became part of Pine Canyon Field. Two wells (section 7 of township 18 north, range 97 west and section 11 of township 14 north, range 102 west) were initially completed as abandoned wells, but were re-entered after 1963 and completed as producing wells. Two wells (section 12 of township 20 north, range 100 west and section 33 of township 21 north, range 99 west) were gas productive but no offset wells were ever productive and they never received a field name. The final two wells (section 18 of township 19 north, range 99 west, and section 28 of township 27 north, range 103 west) tested gas but no production was ever reported and they never got a field name.

Producing Zones

The Wyoming Oil and Gas Conservation Commission (2012) recognizes 130 named fields within the Planning Area. Of these 130 fields, 35 fields (26.92 percent) do not contain any active wells as of April 2012 and 22 fields (16.92 percent) that only contain one active well. In addition there are 88 active wells that are not part of a named field.

Conventional oil and gas occurs in the Planning Area in numerous geologic formations, and members of formations. Twenty-two units have been productive in five or more wells in the Planning Area (IHS Energy Group, 2012). In some wells more than one unit has been productive. From youngest to oldest (see Figure 6) the productive units are:

- Green River Formation 43 wells
- Wasatch/Fort Union formations 52 wells
- Lance Formation 259 wells
- Fox Hills Sandstone 6 wells
- Lewis Shale 141 wells
- Mesaverde Group 189 wells
- Almond Formation 663 wells
- Ericson Sandstone 7 wells
- Rock Springs Formation 12 wells
- Blair Formation 25 wells
- Baxter (Hilliard) Shale 75 wells
- Frontier Formation 1,101 wells
- Mowry Shale 7 wells
- Bear River Formation 69 wells
- Muddy Sandstone 19 wells
- Dakota (Lakota) Formation 270 wells
- Morrison Formation 25 wells
- Nugget Sandstone 42 wells
- Phosphoria Formation 12 wells
- Weber Sandstone 32 wells
- Morgan Formation 5 wells
- Madison Limestone 5 wells

Almost all producing units are of Cretaceous age. There are only a few Tertiary aged producing wells (Green River Formation and Wasatch/Fort Union formations) and a few older than the Cretaceous (the Morrison Formation and older).

The Cretaceous aged Frontier Formation has the most wells that have been completed for production (Figure 18a). Most of these wells are located in the vicinity of the Moxa Arch (northwest and southwest parts of the Planning Area) with a second concentration along the Rock Springs Uplift (Figure 5a) and on its eastern flank. Almost 88 percent of these wells were completed in only the Frontier Formation. Of the Frontier completions that also included completions in other formations, almost 54 percent were also in the Dakota Sandstone, over 21 percent were in the Baxter Shale, and over 19 percent were in the Bear River Formation.

The Cretaceous aged Almond Formation has the second most number of wells completed for production (Figure 18b). Most wells are located in and around the Patrick Draw/Desert Springs field complex (Figure 7) on the Wamsutter Arch and its south flank. Stagecoach Draw Field (located in township 23 north, range 107 west) also contains a concentration of Almond Formation producing wells. Over 97 percent of these wells were completed in only the Almond Formation. Of the Almond completions that also included completions in other formations, almost 74 percent were also in the Lewis Shale and over 10 percent were in the Rock Springs Formation and in the Blair Formation.

The Cretaceous aged Dakota Sandstone has the third most number of wells completed for production (Figure 18c). Most Dakota Sandstone wells are located along the Rock Springs Uplift and its eastern flank with a second concentration on the Moxa arch and its eastern flank (Figure 7). Over 67 percent of these wells were completed in only the Dakota Sandstone. Of the Dakota completions that also included completions in other formations, over 85 percent were also in the Frontier Formation, 4.55 percent were in the Nugget Sandstone, and 3.41 percent were in the Blair Formation.

The Cretaceous aged Lance Formation has the fourth most number of wells completed for production (Figure 18d). Over 90 percent were located within Jonah Field (Figure 7) or the vicinity and the remaining wells are along the eastern border of the Planning Area. Over 98 percent of these wells were completed in only the Lance Formation.

The Cretaceous aged Mesaverde Group (Figure 6) completions (including the Ericson Rock Springs and Blair completions but not including those completions in the Almond Formation) have the fifth most number of wells (Figure 18e). These completions are scattered across the Planning Area than for previously discussed formations, with the majority located in the southeast. Canyon Creek and Trail fields (Figure 7) and Brady Field (Figure 14d) have the biggest concentrations of Mesaverde Group completions. Almost 91 percent were completed just within the Mesaverde Group. Of the Mesaverde completions that also included completions in other formations, almost 29 percent were in the Baxter Shale, over 19 percent were in Tertiary formations, and over 14 percent were in the Almond Formation.

The Cretaceous aged Lewis Shale has the sixth most number of wells completed for production (Figure 18f). Completions are located only on the eastern most side of the Planning Area. More than half of the Lewis Shale well completions are located in the Table Rock/Delaney Rim and Patrick Draw/Desert Springs field areas (Figure 7). Over 87 percent were completed just within the Lewis Shale. Of the Lewis completions that also included completions in other formations, almost 78 percent were completed in the Almond Formation.

Tertiary aged well completions are shown on Figure 18g. Almost all wells are concentrated in three parts of the Planning Area (southeast, northwest, and southwest of Green River, Wyoming). The Massacre Hills Field and surrounding area contains almost 40 percent of the completions. As previously stated, these wells were drilled almost entirely by Saurus Resources, Incorporated and they all have been since abandoned with almost no production. Hiawatha Field (Figure 14b) contains over 21 percent of the completions, Canyon Creek Field (Figure 14b) contains almost 15 percent, East LaBarge (Figure 14c) contains almost 13 percent, and Kinney Field (Figure 14d) contains 3.7 percent. Almost 93 percent were completed just within Tertiary aged formations. Of the Tertiary aged completions that also included other formation completions, 50 percent were in the Almond Formation and 25 percent were in the Lance Formation.

The 86 well completions (Figure 18h) made in Jurassic aged Nugget Sandstones and older formation are located only in and around nine fields. Brady Field (Figure 14d) and its northern extension into township 17 north, range 100 west, contains 36 wells (41.86 percent) completed in Nugget or older zones. Forty-one well completions into these older zones were made in the 36 wells, with 19 in the Weber Sandstone, 14 in the Nugget Sandstone and eight in the Phosphoria Formation. The Table Rock Field area (Figure 14b) contains 31wells (31.05 percent). Thirty-five completions into these older units were made in the 31 wells, with 18 in the Nugget Sandstone, 12 in the Weber Sandstone, four in the Madison Limestone, and one in the Phosphoria Formation. Baxter Basin Field (Figure 14a) contains six wells (6.98 percent) completed in the Nugget Sandstone and Butcher Knife Springs (southwestern part of Planning Area) contains five wells (5.81 percent) completed in the Morgan Formation. The remaining eight wells are located in the remaining five fields. Of the eight wells there were four Nugget Sandstone completions, three Phosphoria Formation completions, one Weber Sandstone completion, and one Madison Limestone completion.

The key source rocks for hydrocarbons occurring within the Planning Area (Roberts, *et al.*, 2005) are:

1. Phosphoria and Niobrara formations are source rocks for oil.
2. Mowry Shale is a source rock for oil at some locations and predominately oil at others where some gas may also be generated.
3. Baxter Shale and upper part of the Mesaverde Group are predominately gas source rocks with the potential for some gas generation.
4. Lewis Shale, Lance Formation, and Fort Union Formation are gas source rocks.

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). Reeves *et al.*, (2007) noted strong levels of industry investment in oil and gas recovery research and development during the 1980s and early 1990s and a decline after that. The National Petroleum Council (2003) postulated that technology improvements would play a lesser role in gas resource enhancement in the 2003-2008 time periods. They also assumed that technology improvements would play a greater role after 2008 when higher gas prices would motivate industry to invest more in development of technology. Future average improvement rates for certain types of technology were assumed to be:

- 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.

Unconventional gas has become a significant potential component of future production within the Planning Area if new reserves can be established. The Energy Policy Act of 2005 established funding for unconventional gas research and development and selected the Research Partnership to Secure Energy for America to oversee and manage new projects (Reeves *et al.*, 2007). The goals of this organization are to:

- Increase the volume of the technically recoverable unconventional gas resource (See Glossary for technically recoverable resource) base by 30 trillion cubic feet,
- Convert 10 trillion cubic feet of technically recoverable unconventional gas to economically recoverable gas,
- Develop technologies for developing unconventional resources with minimum environmental impact, and
- Emphasize science-building capacity and effective technology dissemination.

Technologies that will be required to tap currently undeveloped unconventional gas resources (Reeves *et al.*, 2007) may be:

- Detection methods to find where the highly productive, naturally fractured "fairways" of a play exist,
- Improving reservoir characterization in order to identify the entire productive pay interval,
- Advanced well stimulation methods to establish the low-end of reservoir quality for using well stimulation to yield economic results, and
- Enhanced recovery technology using injection of nitrogen and/or carbon dioxide to accelerate and increase gas recovery from coals, shales, and possibly tight sands.

With the rise in well drilling and well stimulation costs in recent years there had been concerns that much of the unconventional resource may become uneconomic to pursue. Gobec *et al.* (2007) have projected that the pursuit of efficiencies and technology improvements will at least partially offset the recent increases in costs. Costs have leveled out and in some cases decreased in recent months, due to decreases in oil and gas demand and in price. Costs are not expected to increase significantly in the near future. Once oil and gas demand and prices begin to increase again, then costs will also begin to rise.

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 that access restrictions can delay drilling activity by an average of two years. The Energy Information Administration (2001) also assumed that two years would be added to schedules for drilling projects in order to comply with access restrictions. They also assumed that access restrictions would add six percent to the exploration and development costs of projects.

Drilling and Completion Activity

There have been 4,479 conventional surface well locations and 136 coalbed natural gas locations spudded or completed in the Planning Area through October 2, 2012 (Wyoming Oil and Gas Conservation Commission, 2012). Of the 4,479 conventional wells and 136 coalbed natural gas wells spudded or drilled in the Planning Area, 3,107 wells, or 69.37 percent, appear to have been on Bureau managed oil and gas lands.

Conventional wells

Figure 19a presents the locations of all conventional wells that have been spud and not completed and all wells still capable of producing conventional oil and gas (Wyoming Oil and Gas Conservation Commission, 2012) as of October 2, 2012. Of the 4,479 wells spudded or drilled there are 2,139 oil and gas wells (47.76 percent) still in an active status. Of these 2,139 wells, their present status is:

- Gas – Dormant 1 well
- Gas – Spudded 45 wells
- Gas – Producing 88 wells
- Gas – Flowing 1,438 wells
- Gas – Gas Lift 6 wells
- Gas – Pumping Rods 71 wells
- Gas – Pumping Submersible 10 wells
- Gas – Pumping Hydraulic 2 wells
- Gas – Pumping Plunger Lift 1 well
- Gas – Shut-In 229 wells
- Gas – Temporarily Abandoned 10 wells
- Gas – Notice of Intent to Abandon 21 wells

- Oil – Spudded 6 wells
- Oil – Producing 5 wells
- Oil – Flowing 44 wells
- Oil – Pumping Rods 103 wells
- Oil – Pumping Submersible 5 wells
- Oil – Shut-In 48 wells
- Oil – Temporarily Abandoned 2 wells
- Oil – Notice of Intent to Abandon 4 wells

Only about 10 percent of the above wells are classed as oil wells, with the rest classed as gas wells. Many of the spudded gas wells are in the Canyon Creek (30 spudded wells) and Trail (six spudded wells) fields in the southeast part of the Planning Area (Figure 7). These well locations are so close together that they do not show individually at the scale of Figure 19a. Also, there are four spudded oil wells in Table Rock Field (township 19 north, range 97 west), but they are also so close together that only one data point can be seen at the scale of Figure 19a.

Figure 19b presents the locations of all wells that are being used for enhanced oil recovery purposes and for disposal, monitoring, and water source wells as of October 3, 2012 (Wyoming Oil and Gas Conservation Commission, 2012). Of the 4,479 wells spudded or drilled in the Planning Area there are 120 injector, disposal, monitoring, or water source wells (2.68 percent) still in an active status. Of these 120 wells, their present status is:

- Injector – Active Injector 78 wells
- Injector – Shut-In 7 wells
- Disposal – Spudded 1 well
- Disposal – Active 13 wells
- Disposal – Shut-In 6 wells
- Disposal – Notice of Intent to Abandon 3 wells
- Monitor – Spudded 1 well
- Monitor – Shut-In 1 well
- Monitor – Notice of Intent to Abandon 2 wells
- Water Source – Active 8 wells

The 2,259 active conventional wells that are shown in Figures 19a and 19b account for about 50.44 percent of all the 4,479 conventional wells that have been spudded or completed within the Planning Area.

Figure 19c shows the locations of 151 wells that have been permitted for drilling by the Wyoming Oil and Gas Conservation Commission (2012) and 11 applications submitted but waiting on approval. Most wells are located in the Canyon Creek and Trail field areas in the southeast part of the Planning area and on the northwest, along the Moxa Arch and its eastern flank (Figure 5a). Operators may choose not to drill all 162 proposed wells.

About 49.56 percent (2,220 wells) of the 4,479 spudded and completed conventional oil and gas wells have been plugged and abandoned (Figure 19d) and their surface locations have been reclaimed or are in the process of final reclamation. Wells have been abandoned because:

- they were "dry"--no hydrocarbons were encountered, hydrocarbons were not present in economic quantities, or mechanical difficulties within a borehole prevented economic oil and gas production;
- they were considered to be just stratigraphic tests drilled to obtain information about subsurface geologic horizons and their depths; or
- they initially were capable of producing hydrocarbons but they became uneconomic to produce at a later date or they were used in enhanced oil recovery projects, as disposal wells, or as source wells and were no longer needed for those purposes.

Coalbed natural gas wells

There have been only 136 coalbed natural gas wells completed within the Planning Area, with two approved permits to drill still out-standing (Figure 20). As of October 3, 2012 the abandonment rate for these wells has been high: 84 of the wells (61.76 percent) have been abandoned (Wyoming Oil and Gas Conservation Commission, 2012). As discussed previously, a lot of water has been produced along with the gas produced from these wells. Those high water production rates may have led to many of the recent well abandonments. Of the remaining 52 active wells completed in the Planning Area their present status is:

- Flowing Gas 18 wells
- Shut-In 16 wells
- Notice of Intent to Abandon 18 wells

The only wells presently producing gas are those located in townships 14, 18, and 19 north and range 100 west. Wells with notices of intent to abandon are located in:

- Township 14 north, range 101 west 1 well
- Township 16 north, range 101 west 5 wells
- Township 17 north, range 100 west 5 wells
- Township 18 north, range 100 west 1 well
- Township 23 north, range 102 west 6 wells

Drilling Rigs and Rig Counts

The Rocky Mountain Oil Journal (2012) reported that between September 28 and October 4, 2012 there were four active rigs working within the Planning Area. In 2010 operators completed 92 wells and drilled 636,673 feet of borehole, or an average of 6,920 feet per well (IHS Energy Group, 2012). In 2011 operators completed 85 wells and drilled 664,339 feet of borehole. Average well depth increased to 7,816 feet.

Production

Cumulative production (through 2011) within the Planning Area was more than 5.28 trillion cubic feet of gas, more than 180 million barrels of oil, and almost 157 million barrels of water (IHS Energy Group, 2012). Data from the Wyoming Oil and Gas Conservation Commission (2012) was used to compile production by named fields in the Planning Year for the most recent year of data (2011). Table 5 lists 2011 oil, gas, and water production by field and includes some fields (such as Jonah, Table Rock, Pinedale, and LaBarge) that lie at least partially outside the Planning Area. There were 88 fields with at least some hydrocarbon production recognized and a field called "WC" in Table 5 which combines all of the production for wells that do not lie within a named field.

Oil production is not a significant part of most field production within the Planning Area. Oil production totaled 9,132,881 barrels from these fields in 2011. There were six major producing oil fields in the Planning Area (including the "WC" category). In descending order and percent of 2011 total production they were:

- Pinedale (45.01 percent)
- Jonah (29.78 percent)
- Patrick Draw (17.37 percent)
- "WC" (1.76 percent)
- Brady (1.24 percent)
- LaBarge (0.86 percent)

These six fields account for 96.02 percent of 2011 oil production. Brady and Patrick Draw field wells are classed as oil fields and production comes entirely from within the Planning Area. Pinedale, Jonah, and LaBarge field wells are classed as gas fields and they produce associated oil. Wells in these three fields are mostly located outside the Planning Area.

Gas is the predominant hydrocarbon produced within the Planning Area. Gas production totaled 970,310,269 cubic feet from these fields in 2011. In 2011 there were 13 fields (and the "WC" category) that produced more than two billion cubic feet of gas. Those fields (in descending order) and their percent of total production were:

- Pinedale (57.28 percent)
- Jonah (31.48 percent)
- WC (2.81 percent)
- Trail Unit (1.13 percent)
- Fontenelle (1.03 percent)
- Canyon Creek (0.99 percent)
- Table Rock (0.93 percent)
- LaBarge (0.64 percent)
- Lincoln Road (0.34 percent)
- Hay Reservoir (0.34 percent)
- Bird Canyon (0.25 percent)
- Blue Forest, (0.22 percent)

- Mesa (0.22 percent)

These 12 fields (and the “WC” category) account for 97.66 percent of 2011 gas production. All named fields are classed as gas fields. Pinedale, Jonah, LaBarge, and Hay Reservoir fields are mostly located outside the Planning Area. Table Rock, Fontenelle, and Lincoln Road fields lie mostly inside the Planning Area and the remaining six fields are located within the Planning Area.

Water is often produced in conjunction with the production of oil and gas from most reservoirs. Waterflooding projects also cause an increase in associated water (See Glossary) production. Water production by field is shown on Table 5. Water production totaled 91,556,342 barrels in 2011. In 2011 there were six major water producing fields (including the “WC” category”) in the Planning Area (by volume). Those fields (in descending order) and their percent of total production were:

- “WC” (66.19 percent)
- Pinedale (20.78 percent)
- Jonah (4.96 percent)
- Brady (3.74 percent)
- Patrick Draw (2.47 percent)
- LaBarge (0.52 percent)

These five fields (and the “WC” category) account for 98.66 percent of 2011 water production. Again Pinedale, Jonah, and LaBarge fields are mostly located outside the Planning Area and Brady and Patrick Draw are inside.

Oil Mining Activity

Traditional oil and gas development involves drilling wells from the surface to the target formation at depth and bringing the product to the surface using natural formation pressures or by means of artificial lift. In some oil fields, however, a mature, depressurized reservoir located at shallow depths may have a portion of the remaining oil extracted via a process known as "oil mining."

Oil mining is a form of enhanced oil recovery whereby a mine is tunneled beneath the reservoir and a series of wells are drilled upward into the producing formation and gravity drainage is used to extract the oil (Rock Well Petroleum, 2009). Due in part to the limitations on depth of underground mining techniques, only a limited number of mature oil fields are viable candidates for this technique. This type of field is not presently within the Planning Area and no projects are planned.

Marginal Wells

Low-volume oil and gas wells, known as "marginal" or "stripper" wells contribute an important percentage of the hydrocarbons produced in the U.S. In 2005, 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). In 2007, the oil contribution had decreased

to approximately 28 percent and the gas contribution increased to 11 percent – an important contribution to the nation's supply (Interstate Oil and Gas Compact Commission, 2009). In 2009, the oil contribution had decreased further, to 20 percent and the gas contribution remained at 11 percent (Interstate Oil and Gas Compact Commission, 2010).

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 (2010) defines marginal or stripper wells as wells that are producing 10 or fewer barrels of oil per day and no more than 60,000 cubic feet per day of natural gas.

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). The Interstate Oil and Gas Compact Commission (2010) estimated that in 2007 the industry directly created almost 10 jobs and another 15 jobs indirectly for every million dollars of marginal oil and gas production. In addition, as long as these wells remain productive there are additional opportunities to use advanced technology to enhance recovery. The Interstate Oil and Gas Compact Commission (2008) also reported on development of technologies being pursued to improve production performance of the nation's marginal wells.

In 2009, Wyoming ranked 15th in number of marginal oil wells of the 27 states with marginal oil wells and 13th in number of marginal gas wells of the 26 states with marginal gas wells (Interstate Oil and Gas Compact Commission, 2010). In that year there were 3,468 marginal oil wells that produced 3,930,281 barrels of oil in the state of Wyoming, and 5,929 marginal gas wells which produced 45,183,845,000 cubic feet of gas (data for 2010 was not available at the time of this writing).

As of June, 2012 there were 214 active marginal oil and gas wells (IHS Energy, 2012) located within the Planning Area (Figure 21). In addition there were 239 gas wells and 50 oil wells in a shut-in or temporarily abandoned status (Wyoming Oil and Gas Conservation Commission, 2012) that could possibly meet the criteria as marginal wells if they were in a producing status (Figure 21).

Deep Well Drilling: Greater than 15,000 feet

Dyman *et al.* (1990, 1993a, 1993b, and 1997) characterized deep wells as those drilled to depths greater than 15,000 feet. Drilling and completing deep gas wells are very costly due to the extremely high temperatures and variable pressures and hard rock encountered. The IHS Energy Group (2012) database shows that there have been 123 wells drilled to depths of more than 15,000 feet in the Planning Area, and they are scattered across the Planning Area with a number of fields being gas or oil productive at depths below 15,000 feet (Figure 22a).

Of the 123 wells, 74 wells (60 percent) were completed as oil (seven wells), gas (66 wells), or carbon dioxide (one well) producers. The remaining 49 wells were abandoned. Of the 74 productive wells, there were 48 wells that were completed at depths of more than 15,000 feet. The remaining 26 wells were predominately completed in the 10,000 to 15,000 foot range (24 wells) with two wells completed in formations at a lesser depth. Initial deep well completions were in:

- Frontier Formation 5 wells
- Muddy Sandstone 3 wells
- Dakota Sandstone 2 wells
- Nugget Sandstone 18 wells
- Weber Sandstone 13 wells
- Phosphoria Formation 1 well
- Morgan Formation 5 wells
- Madison Limestone 5 wells
- Bighorn Dolomite 1 well

A few wells were completed in more than one formation.

The first deep well was completed in 1968 as a 15,681 foot dry hole with a gas show in township 12 north, range 103 west. The last deep well was completed in 2010 as a 17,010 gas well productive at less than 15,000 in the Mesaverde Group. It is located in township 27 north, range 106 west. The deepest well was a 25,764 foot drilled and abandoned wildcat, with a gas show, located in township 27 north, range 103 west that was spudded in 1978 and completed in 1982. It bottomed in the Madison Limestone.

The oldest formation tested was the Cambrian aged Flathead Sandstone (Figure 6) tested in section 16 of township 16 north, range 101 west. It was completed as an oil well at less than 15,000 feet. The deepest producing zone was in the Bitter Creek Unit #5 drilled (section 22 of township 16 north, range 99 west) at Bitter Creek Unit Field (Figure 22a). The Frontier and Dakota were initially productive between 20,002 and 20,646 feet in this well.

Deep Well Drilling and Completion Activity: 10,000 to 15,000 feet

There have been 1,080 known boreholes in the Planning Area that have drilled to the 10,000- to 15,000-foot depth range (IHS Energy Group, 2012). As Figure 22b shows, most wells in this depth range are located in the northwest corner of the Planning Area, with a significant number in the southeast, northeast, and southwest corners. Completion status of these wells has been split between drilled and abandoned, junked and abandoned, temporarily abandoned, suspended, and pilot wells (191 wells or 17.69 percent), oil wells (40 wells or 3.7 percent), gas wells (825 wells or 76.39 percent), and other well types (24 wells or 2.22 percent).

Fields (Figure 22b) with the most wells drilled in this depth range are:

- Jonah Field 238 wells
- Lincoln Road Field 121 wells
- Mesa Field 85 wells

- Blue Forest Field 59 wells
- Bird Canyon Field 48 wells
- Brady Field 46 wells
- Swan Field 26 wells
- Henry Field 17 wells

Most of the oil wells (25 wells or 62.5 percent) are located in Brady Field (Figure 22b). An additional four are located in Henry Field and the rest are scattered across the Planning Area. The predominate oil producing formations are:

- Dakota Sandstone 15 wells
- Nugget Sandstone 14 wells
- Weber Sandstone 8 wells
- Frontier Formation 5 wells

Some wells were initially completed in more than one formation.

The predominate gas producing formations in this depth range are:

- Frontier Formation 342 wells
- Lance Formation 238 wells
- Dakota Sandstone 109 wells
- Mesaverde Group (including Almond) 78 wells
- Lewis Shale 31 wells
- Bear River Formation 30 wells

Shallower Well Drilling: 5,000 to 9,999 feet

The greatest number of wells drilled (2,094) in the Planning Area have been drilled to the 5,000- to 9,999-foot depth range (IHS Energy Group, 2012). As Figure 22c shows, wells in this depth range are predominately located in the northwest part of the Planning Area and east of US highway 191, but south of township 24 north. Completion status of these wells has been split between drilled and abandoned, temporarily abandoned, junked and abandoned, and suspended wells (577 wells or 27.55 percent), oil wells (287 wells or 13.71 percent), gas wells (1,147 wells or 54.78 percent), injection wells (51 wells or 2.43 percent) and other well types (32 wells or 1.53 percent).

The largest portion of wells has been drilled in the fields in the northwest (west of range 110 west) part of the Planning Area (611 wells or 29.18 percent). The next highest concentration of wells drilled in this depth range is near the eastern border of the Planning Area in townships 17-21 north, ranges 97-99 west (Figure 22c). There were 556 wells drilled or 25.55 percent of the total. In the north-central part of the Planning Area (townships 21-24 north, ranges 103-104 west) 202 wells or 9.65 percent of the total wells were drilled. Finally, in the southeast (townships 12-13 north, ranges 99-101 west) 179 wells or 8.55 percent of the total wells were drilled.

Almost all of the oil wells are concentrated along the eastern border of the Planning Area and almost all (230 wells or 80.14 percent) were completed in the Almond Formation in

this well depth range. Most of the remaining wells were completed in the Lewis Shale (34 wells or 11.85 percent).

Gas wells are productive from a number of formations in the Planning Area. The formations with the largest productive numbers of wells in the depth range are:

- Frontier Formation 678 wells
- Mesaverde Group (excluding Almond) 142 wells
- Almond Formation 133 wells
- Dakota Sandstone 84 wells
- Lewis Shale 60 wells
- Baxter Shale 42 wells
- Bear River Formation 38 wells

Shallowest Well Drilling: Less than 5,000 feet

There have been 1,103 known boreholes in the Planning Area that have drilled to the less than 5,000 feet (IHS Energy Group, 2012). As Figure 22d shows, most wells in this depth range are located in the Union Pacific Railroad Land Grant, with smaller concentrations in the southeast and the northwest. This drilling depth accounts for the largest percentage of wells that were drilled and abandoned. Five hundred thirty-nine wells or 48.87 percent were drilled and abandoned, junked and abandoned, or temporarily abandoned. Completion status of the remaining wells is split between oil wells (236 wells or 21.4 percent), gas (271 wells or 24.57 percent), injection wells (33 wells or 2.99 percent) and other well types (24 wells or 2.18 percent).

Twenty-four wells were drilled to depths of less than 500 feet, with only one completed as a gas well. It was completed in township 17 north, range 107 west (Figure 22d). This was a Saurus Resources Incorporated well, previously discussed, that never reported production. The shallowest reported production comes from the wells drilled in the same township and range by Saurus Resources Incorporated. Some of these wells produced small amounts of gas from completed intervals between 1,000 and 2,000 feet from the Wilkins Peak Member of the Green River Formation.

Almost all of the 236 oil wells are productive in the Almond Formation (89.41 percent). A larger number of formations report gas production. Of the 271 gas wells the formations with the largest number of productive wells are:

- Tertiary 72 wells
- Almond Formation 56 wells
- Frontier Formation 55 wells
- Dakota Sandstone 41 wells
- Morrison Formation 16 wells
- Mesaverde Group (excluding the Almond) 14 wells
- Lewis Shale 12 wells

Some wells were initially completed in more than one formation.

Coalbed Natural Gas Drilling Depths

Well depths in the coalbed natural gas wells drilled (Figure 20) have varied from as shallow as 750 feet to 12,258 feet. Productive perforated intervals have been in the 1,000 to 5,300 foot range. Producing intervals, from youngest to oldest are:

- Fort Union Formation 23 wells
- Lance Formation 6 wells
- Mesaverde Group 8 wells
- Almond Formation 73 wells
- Rock Springs Formation 11 wells

Summary of Current Drilling Techniques

Most oil and gas wells have been drilled vertically throughout the Planning Area, with directional and horizontal wells mostly being drilled in recent years. Developments in drilling techniques have allowed for more widespread use of directional and horizontal drilling technology. Directional drilling has many benefits, but also some limitations. For instance, directional drilling may be employed to avoid sensitive or inaccessible surface features, increase the area that a borehole contacts a producing formation, and when multiple directional wells are drilled from the same vertical borehole or from the same surface location, reduce drilling time, associated waste volumes and emissions, and provide greater protection of sensitive environments. Most of this technology will be tested first in other regions where economic returns on investment are higher than in the Planning Area. Where technology is shown to provide significant cost benefits, local operators will begin to apply those methods when appropriate.

Directional and Horizontal Drilling and Completion Activity

In addition to the benefits of directional and horizontal drilling outlined above, such boreholes will often be allowed to “drift” updip along the flanks of geologic structures (e.g., along the axis of a plunging anticline), thereby naturally contacting more of the producing formation. Depending on subsurface geology, technology advances now allow operators to deviate boreholes by anywhere from a few degrees to completely horizontal. Deviation allows operators to reach reservoirs that are not located directly beneath the drilling rig, or to allow the borehole to contact more of the reservoir. In some cases directional drilling may be used specifically for avoidance of unfavorable surface locations. 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 *et al.* (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, 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 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 Planning Area have traditionally been drilled vertically. Of the 4,479 conventional wells drilled in the Planning Area, IHS Energy Group (2012) reports 366 boreholes (8.17 percent) were drilled directionally and 78 wells have been proposed but not spudded. They also report that 33 boreholes (0.74 percent) were drilled horizontally and 15 have been proposed but not spudded (Figure 23). No coalbed natural gas wells were drilled directionally and only one was drilled horizontally in section 31 of township 14 north, range 100 west (Figure 20). The vertical wells producing in the Planning Area are completed in a variety of formations for both gas and oil. Vertical well depths range from a number of dry holes drilled only a few tens of feet deep to 25,764 feet in section 34 of township 27 north, range 103 west (Figure 22a). Horizontal wells in the Planning Area have boreholes as long as 18,446 feet (vertical depth plus horizontal lateral distance), though the deepest (true vertical depth) horizontal well was drilled to 14,864 feet, and contained a horizontal lateral of 3,582 feet. This well was productive in the Frontier Formation in section 30 of township 25 north, range 108 west (Figure 23). Similarly, directional wells in the Planning Area have boreholes (vertical depth plus horizontal lateral distance) as long as 18,650 feet (in Table Rock Field section 1 of township 18 north, range 98 west) and productive in the Weber Sandstone. Since most directional well bores are S-shaped, the true vertical depth and measured depths (borehole lengths) are usually within a few percent of each other.

Figure 23 shows the locations of conventional directional and horizontal wells drilled and proposed within the Planning Area as reported by IHS Energy (2012). Of the 366 drilled directional wells, their status is:

- 275 gas wells

- 15 oil wells
- 12 injection wells
- 47 spudded wells but did not have a completion status
- 17 abandoned wells (12 drilled and abandoned, three junked and abandoned, and two temporarily abandoned)

The earliest known directional well drilled in the Planning Area is the Argo Oil Company's #1 well in an unnamed field completed in 1961 (IHS Energy, 2012). This well was drilled and abandoned in section 30 of township 14 north, range 100 west (Figure 23). The most recent productive directional well drilled was a Chevron USA Incorporated Almond Formation oil well completed in Table Rock Field (township 19 north, range 97 west) in December of 2011. Of the 366 drilled directional wells 205 (56 percent) are located in the northwest part of the Planning Area. There were 133 wells (36 percent) drilled in the southeast part. Proposed directional wells are located in the northwest part of the Planning Area and in the southeast, in Canyon Creek and Trail fields.

Directional wells have been drilled to various formations. The formations with the most completed productive wells area:

- Lance Formation 101 wells
- Frontier Formation 99 wells
- Mesaverde Group 51 wells
- Baxter Shale 19 wells
- Almond Formation 14 wells

Almost all the Lance and Frontier completions and almost half of the Baxter completions were located in the northwest part of the Planning Area. Almost all of the Almond and Mesaverde and about half of the Baxter completions were located in the southeast part (Figure 23).

Forty-one different operators have drilled the 366 directional wells in the Planning Area. Those operators that have each drilled 20 or more wells are:

- Wexpro Company 83 wells
- Encana O&G USA, Inc. 69 wells
- EOG Resources, Inc. (Enron) 28 wells
- McMurry Oil Company 27 wells
- XTO Energy, Inc. 24 wells
- BP America (Amoco) 23 wells
- Anadarko E&P Company 21 wells

The majority (275 wells or 75 percent) have been drilled by these seven companies.

Horizontal boreholes have been used with less frequency in the Planning Area. Of the 33 wells spudded (Figure 23) their status is:

- 24 gas wells
- 1 oil well

- 2 injection wells
- 2 spudded wells but did not have a completion status
- 5 abandoned wells (two drilled and abandoned, two junked and abandoned, and one temporarily abandoned)

The only horizontal oil well was completed as an Almond Formation producer in Table Rock Field in township 18 north, range 98 west (Figure 23). The completed gas wells recorded initial production from:

- Frontier Formation 10 wells
- Baxter Shale 5 wells
- Almond Formation 3 wells
- Phosphoria Formation 2 wells
- Blair Formation 1 well
- Mesaverde Group 1 well
- Lewis/Lance 1 well

The earliest known horizontal borehole, the Texaco Stagecoach Draw #5H in section 31 of township 23 north, range 107west was completed as a gas well in the Almond Formation. The most recent completed horizontal borehole drilled was the Devon Energy gas well in an unnamed field in section 4 of township 12 north, range 102 west. It was completed as a Baxter Shale producer.

While several fields contain horizontal boreholes, nearly half (16 wells or 48.48 percent) have been drilled in the northwest part of the Planning Area (Figure 23). Nine wells were completed in the Frontier Formation and two in the Almond Formation in this area. An equal number of wells were drilled in the southeast (south of Interstate 80). These wells produce from seven different formations. The remaining horizontal well drilled north of Interstate 80 in township 21 north, range 98 west was completed as a Frontier Formation gas well.

Thirteen different operators have drilled the 34 horizontal boreholes in the Planning Area, with EOG Resources, Incorporated drilling five boreholes. The other 12 operators have drilled between one and three boreholes each (IHS Energy Group, 2012).

While only 34 horizontal boreholes have been drilled in the Planning Area, it should be noted that there are 15 boreholes permitted but not yet spudded. Several formations in the Planning Area could conceivably contain resource plays which generally lend themselves to horizontal completions, so additional horizontally drilling activity is anticipated in the future.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used extensively in the Rocky Mountain Area. At Madden Field, northeast of the Planning Area, some Lower Fort Union Formation wells have been drilled using slimhole drilling technology. Domain Energy drilled three slimhole wells in the Powder River

Basin. Some early wells were drilled on the Wamsutter Arch in 1994 and on the Moxa Arch in 1995. It has the potential to improve efficiency and reduce costs of both exploration and development drilling. Coiled tubing—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. They have been used at Teapot Dome Field in the Powder River Basin of Wyoming. More than 1,103 wells in the Planning Area have been drilled to depths less than 5,000 feet (Figure 22d). Future wells drilled in this depth range would be amenable to coiled tubing rigs.

A review of coiled tubing drilling and intervention (well work during the life of a well) and its advantages, disadvantages, and limitations was presented for 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
- reduced chance of damaging underpressured formations

One new use is to mill out plugs used in long horizontal lateral boreholes used in unconventional shale gas production (Mazerov, 2010). If these types of wells begin to be drilled more often in the Planning Area then more use of coiled tubing will occur.

Coiled tubing will most likely be first used in some workover situations in the Planning Area. I expect both of these drilling and completion techniques to be used more often in the future. U.S. Department of Energy (1999) has identified the environmental benefits of using these techniques, which include:

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

Drilling with Casing

Fontenot *et al.* (2005) studied the emerging use of casing for drilling. This use can reduce well-construction costs, improve efficiency and safety, and minimized environmental impact. This drilling technique uses the large-diameter casing to drill the well that well be permanently installed in the wellbore if the well is successful. BP America Production Company successfully used this technique to drill surface and production casing intervals in 15 gas wells on the Wamsutter Arch area in 2001. This technique has been mostly used in drilling vertical wells.

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 in the Jonah Field and to the north at Pinedale Field is now common. If other similar high productivity reservoirs are discovered in the Planning Area these types of rigs will become more common.

Light modular rigs also have potential for use in situations where pad drilling is being used. Pad drilling refers to the drilling of multiple directional boreholes from one surface location. Pads are the flat graded land surfaces that serve as the foundation for the drilling rig. Since modular rigs allow quicker breakdown and movement to new locations, they reduce time to drill and rig costs. Several formations in the Planning Area could conceivably contain resource plays which generally lend themselves to directional or horizontal completions and thus pad drilling.

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. Only a few fields in the Planning Area meet these criteria. 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 would be critical for use in drilling horizontal boreholes within the Planning 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). Additional improvements have continued to be made to enable faster drilling. Environmental benefits of improved bits include:

- lower waste volumes

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

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

Summary of Current Completion Techniques

Standard completion techniques for the Planning 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. The casing also serves to protect sources of groundwater from contamination by oilfield fluids.

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.

A limited number of horizontal wells have been drilled to date. New types of horizontal fracturing technology will likely be used to stimulate these types of wells in the future. Development could be similar to that used to stimulate the Bakken Formation Middle Member in North Dakota. For horizontal boreholes, multi-stage fracture stimulations could be used. The Energy Information Administration (2006b) has reported that once the Bakken Formation has been fractured an uncemented pre-perforated liner is installed in the borehole.

The final completion step is to place production 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.

SUMMARY OF CONVENTIONAL OIL AND GAS PRODUCTION AND ABANDONMENT TECHNIQUES

Once production begins application of reservoir management procedures are needed to ensure the 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 (See Glossary for (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 nine 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.

Operating costs in the U.S. rose during the middle part of this decade and then began to fall in 2009 (Energy Information Administration, 2010). Direct annual oil operating costs for 2006 through 2009 are shown in Table 6a for wells producing at 8,000 feet and 12,000 feet. Direct annual gas operating costs for the same period and well depths, with an additional split for production at 250 thousand cubic feet per day and 500 thousand cubic feet per day is shown in Table 6b.

Reserve additions in the United States at December 31, 2010 went up (Energy Information Administration, 2012). Crude oil plus lease condensate reserves went to 25.2 billion barrels (an increase of 12.8 percent from the previous year) and wet natural gas reserves went to 317.6 billion cubic feet (an increase of 11.9 percent). In Wyoming crude oil plus lease condensate proved reserves (See Glossary for proved reserves) additions did not keep pace with production so proved reserves dropped by 32 million barrels to 823 million barrels of reserves for 2010. In 2010 there was one field discovery, no new reservoir discoveries, and 32 extensions (reserve additions resulting from additional drilling and exploration in previously discovered reservoirs).

In 2010, Wyoming natural gas proved reserve additions also did not keep pace the gas production rate. Reserves declined slightly from 36.747 trillion cubic feet to 36.525 cubic feet. In 2010, there was one field discovery, no new reservoir discoveries, and 2,205 extensions. In the Planning Area oil and gas reserve additions in recent years have come from the drilling in previously discovered reservoirs.
The Energy Information Administration (2010) has shown that the cost of equipping and operating gas wells in the Rocky Mountains is higher than the average for onshore 48 contiguous states. Cleveland (2003) indicated a number of reasons why Rocky Mountain gas wells may be more expensive to equip and operate. Reasons for extra costs that may apply to the Planning Area are:

- access to well sites is generally more difficult due to remoteness from the main activity areas and sometimes steep terrain
- harsh environments (particularly cold temperatures)
- changes in rig availability

- changes in development priority as industry focus on certain plays evolves with new discoveries and changes in oil and gas price
- labor market conditions
- restrictions (many of them environmental restrictions of some type) on land use

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:

- Primary Recovery - 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.
- Secondary Recovery – 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.
- Enhanced Oil Recovery - 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 U.S. Department of Energy, as much as 90 percent of the oil originally in-place in an oil reservoir is left behind once primary recovery methods are completed (U.S. Department of Energy, 2008a). 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 percent. However, the primary recovery factor varies depending on oil and reservoir characteristics, but as a general rule 15-20 percent is considered the norm (Sandrea and Sandrea, 2007). Primary recovery relies on the natural pressure found in the reservoir and artificial lift (generally some type of pumping method) 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 of the methods used to recover additional hydrocarbons were cost prohibitive and a large percentage of the oil or gas in any given reservoir was left behind until cost effective methods off recovery could be developed.

As newly discovered volumes of oil and gas decline and demand, and consequently price, for oil and gas climbs, methods for removing additional oil and gas that was previously left behind in reservoirs 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 injecting into wells to physically "push" 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 the oil down a pressure gradient 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 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 reservoir location can also be important in enhancing an oil recovery project's feasibility. For example, proximity to a carbon dioxide source is a factor in choosing a carbon dioxide injection project. A nearby source of fresh or treatable water is needed for waterflood projects and for use in steamflood or chemical injection projects. Oil and gas prices play a very important role in determining whether the additional costs associated with an enhanced oil recovery project will allow it to be viable economically. Oil and gas prices may also play a part in deciding the specific type of recovery project would be appropriate. There are few oil fields within the Planning Area (Figure 19a), and few that would be candidates for different types of enhanced oil recovery projects. Waterflood injection projects historically were the first method of increasing oil recovery in the Planning Area and fewer other flood types have been used.

Secondary and Enhanced Recovery Projects in Rock Springs Field Office Planning Area

Waterflooding and Gas Injection

In waterflooding the injected fluid is water. Waterflooding typically yields an extra 10 to 25 percent of the original oil in place (Nummedal *et al.*, 2003). Many Wyoming oil reservoirs are good candidates for waterflooding, and waterfloods were the initial method used to recover additional oil reserves in and around the Patrick Draw Field area (Figure 14d) in the Planning Area.

Gas injection typically refers to the re-injection of produced natural gas into a producing oil formation (as opposed to disposal injection into another formation). In today's market, most produced natural gas is sold rather than re-injected. Currently there are no active secondary recovery gas re-injection projects in the Planning Area. At Henry Unit (Figure 10) Cabot Oil and Gas operated a Dakota Sandstone gas recycling/pressure maintenance injection project which terminated in 1985. At Raptor Unit (Figure 10) ANR Production Company cancelled a Dakota Sandstone pressure maintenance injection project in 1990. Finally, at Pretty Water Creek Field (Figure 14d) Ibex Resources Operating terminated a Phosphoria Formation gas and water recycling injection project in 2002.

Of the three secondary waterflood recovery projects in the Planning Area, only one is active. At Table Rock Unit (Figure 10) a pilot waterflood of the Almond Formation, Ericson Sandstone, and Fox Hills Sandstone was approved in 2010. Chevron USA, Incorporated is the operator. Anadarko E&P Company operated a now terminated waterflood at the Arch Unit (Figure 10) that was approved in 1964 to inject into the Almond Formation. Finally, Anadarko E&P Company operated a waterflood at the Monell Unit (Figure 10) that was approved in 1963 to inject into the Almond Formation. It was converted to carbon dioxide injection flood that will be discussed later.

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. There are no active steamflooding projects in the Planning Area.

Polymer-Enhanced Waterflooding

Polymer-enhanced waterflooding is used to control mobility of injected water. It improves volumetric sweep efficiency and reduces channeling and breakthrough hence it improves overall recovery. There are no active polymer-enhanced waterfloods within the Planning Area.

Surfactant Flooding

Adding surfactants to injected water can enhance oil production. A type of surfactant flood called a micellar flood uses a two-step enhanced oil recovery process in which a small quantity of surfactant is injected into the well followed by a larger quantity of water containing a high-molecular-weight polymer which pushes the chemicals through the field and improves mobility and sweep efficiency. These types of projects are expensive and are not often used, and no such projects exist within the Planning 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. While not nearly as effective as carbon dioxide injection (another method wherein a gas, in this case carbon dioxide, is injected into the reservoir) in-situ combustion is much more cost effective since the injected gas (usually atmospheric air) would be free. There are presently no active in-situ combustion enhanced recovery projects in the Planning Area.

Carbon Dioxide Injection

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

- 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 react with the oil, followed by pumping in three separate stages,
- injection of a small amount of carbon dioxide, called a "slug," which is 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.

Carbon dioxide enhanced oil recovery in the U.S. has been constrained by economics, technology, carbon dioxide supply, and pipeline infrastructure. Most of the injected

carbon dioxide stays in the reservoir and is sequestered. Some carbon dioxide may move into producing wells where it is separated, recovered, and reinjected. Depending on the efficiency of this flooding process, it can recover an additional five to 20 percent of the original oil-in-place (Nummedal *et al.*, 2003). This flooding process has been working well at a number of fields in other parts of Wyoming (Lost Soldier, Wertz, and Salt Creek) as well as at Monell Unit.

The Monell Unit (Figure 10) is the only carbon dioxide injection project in the Planning Area. The field was discovered in 1959, had original oil in place of 118 million barrels in the Almond Formation, and had produced 40 million barrels of oil (Isaacs, *et al.*, 2009). The unit was producing less the 15 barrels of oil per day with a waterflood when a pilot carbon dioxide injection project began in 2001. A pipeline was then installed to bring carbon dioxide to the unit and injection began in 2003. The operator injects 100 percent carbon dioxide into the Almond Formation and plans to eventually sequester 85 billion cubic feet of carbon dioxide into the reservoir (Gaines, 2008). Through 2011 the operator had produced an additional 7.41 million barrels of oil using the carbon dioxide flood (Cook, 2012) or about six percent of the original oil in place. To date the carbon dioxide gas used in continuous flooding has been coming from the Shute Creek processing plant in the Planning Area.

Nummedal *et al.* (2003) listed Brady Field (Figure 22b) as the only additional candidate for carbon dioxide enhanced oil recovery in the Planning Area (Figure 36).

Hydrogen Sulfide Occurrence

Hydrogen sulfide is a colorless, flammable gas that occurs naturally in most crude oil and many natural gas reservoirs (Levorsen, 1967). Hydrogen sulfide is toxic to humans and animals, and a single breath may provide enough exposure to be fatal (International Programme on Chemical Safety, 1994). It has a characteristic foul, or "rotten egg" odor, and is heavier than air, so it tends to accumulate in low-lying areas. Hydrogen sulfide is an impurity that must be removed from oil or natural gas through desulfurization in oil refineries and natural gas "sweetening" plants (natural gas containing hydrogen sulfide is commonly referred to as "sour gas") (Skrtic, 2006). The presence of hydrogen sulfide in hydrocarbons is problematic not only because it is an impurity that must be removed in processing, but also because it is corrosive to metals both as a free gas and in solution, and because of its toxicity to personnel, wildlife, and the public. On Federal lands, operators are required by law to follow specific safety practices and have public protection plans in place where hydrogen sulfide can "reasonably be expected to be present in concentrations of 100 parts per million or more in the gas stream" (43 CFR 3160).

DeBruin (2012) has cataloged fields known to contain hydrogen sulfide. Those fields located in the Planning Area are:

- Brady
- Butcher Knife Springs
- Higgins

- Table Rock

In these fields hydrocarbon production in Nugget Sandstone and older formations (Figure 6) tends to have at least some associated hydrogen sulfide gas. Small amounts of carbon dioxide are also commonly associated with the hydrogen sulfide gas in these fields. Both gases have also occasionally been reported in some wells of the Baxter Basin fields. Any future drilling to formations older than those of Cretaceous age are likely to have at least small amounts of hydrogen sulfide gas present in any reservoir tested.

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 recover these unwanted gases and sweeten the hydrocarbon product for sale. Improvements in the removal 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. Two acid gas plants are located within the Planning Area. Merit Energy Company operates the Brady plant in section 11 of township 16 north, range 101west. It went on line in 1975 and is reported to be the world's largest acid gas injection facility. Substantial amounts of hydrogen sulfide and carbon dioxide are stripped from the hydrocarbon stream of the Nugget and Weber sandstones and is disposed into the subsurface (in two wells in sections 2 and 11 of township 16 north, range 104 west (Figure 19b).

Table Rock gas plant in section 23 of township 19 north, range 98 west is operated by Chevron USA and has been in operation since it was built in 1977. Hydrogen sulfide and carbon dioxide are removed as well as condensate liquids. It takes gas from the nearby Table Rock and Higgins units (Figure 10). Acid gas disposal and salt water disposal wells are nearby.

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 many of the older producing areas of the Planning Area.

Glycol Dehydration

In the Planning Area, 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

Coproduction of a variable amount of water with oil and gas is unavoidable at most locations. As previously stated almost 157 million barrels of water have been produced in the Planning Area. Table 5 presents water production by named field for 2011. Wyoming 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 pond, or discharge into a surface water source through an outfall permit. Table 7 summarizes the active water disposal wells located in the Planning Area.

Figure 24 documents the geographic distribution of water quality samples across the Planning 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 637 samples and total dissolved solids range from 1,021 to 153,656 milligrams per liter. Water quality sample distribution is:

- less than 5,000 milligrams per liter – 107 samples or 16.8 percent
- 5,000 to 9,999 milligrams per liter – 138 samples or 21.66 percent
- 10,000 to 49,999 milligrams per liter – 321 samples or 50.39 percent
- Greater than 50,000 milligrams per liter – 71 samples or 11.15 percent

Some wells reported more than one sample taken.

The Bureau considers total dissolved solids concentrations of less than 10,000 milligrams per liter to be fresh water. Approximately 38.46 percent of these water quality samples fall within this range. Nine parts of the Planning Area have concentrations of water quality samples (Figure 24). Those areas area:

1. The northwest (west of township 109 west) part of the Planning Area has 81 samples tested for total dissolved solids concentrations. Maximum concentrations are lower than any other part of the Planning Area. They range from 1,050 to 20,814 milligrams per liter. Twelve tests were below 5,000 (seven in the Tertiary, four in the Mesaverde Group, and one in the deeper Frontier Formation. Fifty-five tests were between 5,000 and 9,999 (49 in the Tertiary, two in the Mesaverde/Tertiary, and four in the deeper Frontier). Of the remaining 14 samples eight were in the Tertiary (10,596 to 12,171 milligrams per liter) and the other six were deeper Dakota Sandstone samples between 13,894 and 20,814 milligrams per liter.
2. The southwest (west of township 11 west) part of the Planning Area has eight samples tested. Five samples were in Cretaceous aged sediments and were in the 1,822 to 13,076 milligrams per liter range. Three samples were in the deeper Nugget Sandstone and Morgan Formations (greater than 14,597 feet) and had concentrations from 52,260 to 76,557 milligrams per liter.
3. At Baxter Basin north, south, and middle fields 168 samples have been reported. For the 13 samples testing less than 5,000 milligrams per liter the deepest interval was 6,217 to 6,247 feet and five formations were sampled from youngest to oldest:

- Frontier – 1 sample
- Dakota – 3 samples
- Morrison – 6 samples
- Nugget – 2 samples
- Weber – 1 sample

There are 30 samples in the 5,000 to 9,999 milligrams per liter range, with 10 samples of Cretaceous age (Frontier and Dakota), 15 of Jurassic aged (Morrison, Entrada, and Nugget), one of Triassic age, two in the Phosphoria, and one in the Tensleep. There are 115 samples in the 10,000 to 49,999 milligrams per liter range, with 60 of Cretaceous age (Frontier, Dakota, and Muddy), 41 of Jurassic age (Morrison, Entrada, and Nugget), two in the Phosphoria, eight of Pennsylvanian age (Tensleep and Weber), and a few unknown formation names. Finally, there were only 10 samples greater than 50,000 milligrams per liter, with the highest at 88,893 milligrams per liter. There were six samples of Cretaceous age (Frontier and Dakota), one of Jurassic age (Entrada), and three of Pennsylvanian age (Weber and Morgan).

4. At the fields just north of the Baxter Basin Fields 18 samples have been analyzed. There are six samples at less than 5,000 milligrams per liter, with the Almond having three, Rock Springs two, and Frontier one sample. The 5,000 to 9,999 milligrams per liter range has only three samples, with one each in the Frontier, Dakota, and Morrison. There are seven samples in the 10,000 to 49,999 milligrams per liter range, with five Cretaceous aged (Mesaverde and Frontier), on Morrison, and one unknown. Finally, there were only two samples greater than 50,000 milligrams per liter, with a Rock Springs sample at 64,840 and a Nugget sample at 95,670 milligrams per liter.
5. At Middle Mountain Field 11 samples have been analyzed. Two samples are at less than 5,000 milligrams per liter, one in the 5,000 to 9,999 milligrams per liter range, and five in the 10,000 to 49,999 milligrams per liter range. All eight samples are from the Mesaverde Group. Finally, there were three samples greater than 50,000 milligrams per liter, with a Mesaverde sample at 74,505 and two Nugget samples at 50,835 and 61,117 milligrams per liter.
6. In the southeast part of the Planning Area (in and around Canyon Creek, Trail, and Hiawatha fields) there are 159 samples. There are 15 samples at less than 5,000 milligrams per liter, with the Tertiary having seven and Cretaceous aged rocks (Fox Hills, Almond, Mesaverde, and Baxter) having the remaining eight. The 5,000 to 9,999 milligrams per liter range has 16 samples, with 12 in the Tertiary and four in the Mesaverde. There are 60 samples in the 10,000 to 49,999 milligrams per liter range, with 17 Tertiary aged, three Lance, one Fox Hills, 30 Mesaverde, one Morrison, two Nugget, and one unknown. Finally, there were eight samples greater than 50,000 milligrams per liter, with seven Tertiary and one Lance. The largest analysis is 145,481 milligrams per liter. This area has the highest dissolved solids concentrations of the nine areas discussed.
7. In and around Brady Field there are 14 samples recorded. There are three samples at less than 5,000 milligrams per liter, with the Lance having two and the Mesaverde one sample. The 5,000 to 9,999 milligrams per liter range has two

samples, with both in the Mesaverde. There are five samples in the 10,000 to 49,999 milligrams per liter range, with one Lance, two Mesaverde, and two in the Weber. Finally, there were four samples greater than 50,000 milligrams per liter, with one in the Almond and three in the Mesaverde. The largest analysis in this area was 107,184 milligrams per liter.

8. In and around Table Rock Field there are 26 samples recorded. There are five samples at less than 5,000 milligrams per liter, with one Fort Union, one Lewis, two Almond, and one Nugget sample. The 5,000 to 9,999 milligrams per liter range has two samples, with one in the Mesaverde and one in the Nugget. There are 13 samples in the 10,000 to 49,999 milligrams per liter range, with one Fort Union, one Lance, four Almond, five Mesaverde, and two in the Nugget. Finally, there were six samples greater than 50,000 milligrams per liter, with one in the Almond and five in the Mesaverde. The largest analysis in this area was 115,725 milligrams per liter.
9. In and around Patrick Draw/Desert Springs Field there are 73 samples recorded. There are eight samples at less than 5,000 milligrams per liter, with one Lewis, five Almond, one Mesaverde, and one unknown formation sample. The 5,000 to 9,999 milligrams per liter range has 13 samples, with six in the Lewis, six in the Almond, and one in the Mesaverde. There are 37 samples in the 10,000 to 49,999 milligrams per liter range, with, three Lewis, 24 Almond, and 10 Mesaverde. Finally, there were 15 samples greater than 50,000 milligrams per liter, with two in the Fox Hills, seven in the Almond and six in the Mesaverde. The largest analysis in this area was 89,595 milligrams per liter.

A freeze-thaw/evaporation process has been shown to be useful in separating out dissolved solids, metals, and chemicals that are contained in water produced along with the oil and gas production of wells. In 1998, this type of produced water facility was determined to be successful in Jonah Field (PTTC, 2002). It could probably be successfully used in other parts of the cold climate of the Planning Area, in locations where production of poor quality water cannot be disposed of by other means.

The Gas Technology Institute tested the performance and costs associated with the application of electrodialysis to produced water management (Hayes, 2004). A pilot was set up northeast of the Planning Area at a conventional-well site in the Wind River Basin near Lysite, Wyoming. The produced water at this site contained about 8,300 to 10,000 milligrams per liter of total dissolved solids. This pilot showed that the electrodialysis process was capable of demineralizing a conventional gas produced water stream from 9,000 milligrams per liter to 1,000 milligrams per liter for only three cents per 42 gallon barrel, and one cent per barrel to reach 2,500 milligrams per liter. The pilot has yet to be replicated or expanded upon in the Planning Area; however, the process appears viable and could reasonably be expected to be implemented at sites within the Planning Area during the Analysis Period.

High Sierra Water Holding set up a water processing facility just north of the Planning Area in 2002. It treats frac and production water from the area. It can process up to

60,000 barrels per day for frac recycling or 20,000 for water discharge into local streams. The company has treated over 30 million barrels since opening.

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. Leak detection surveillance is used at Pinedale and Jonah fields to help reduce emissions to protect air quality.

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. At Jonah they are trying to recover storage tank vapors and losses in the dehydration process (EnCana, 2008). Some of the strategies used at Jonah and Pinedale fields have included installing volatile-organic-combustors on condensate tanks, using vapor-recovery units, inspecting valves and pipes with ultraviolet cameras to find and fix leaks, and replacing high-bleed pneumatic valves with low-bleed valves (Webb, 2011).

PLANT SITES

In addition to the two acid gas plant sites already discussed there are two other gas plants in the Planning Area. At the Vermillion gas plant in section 14 of township 13 north, range 101 west QEP Field Services Company accepts sweet gas from Canyon Creek and Trail Fields and wells to the east and separates natural gas liquids (See Glossary for natural gas liquids). The plant went on line in 1999. At the Patrick Draw gas plant in section 25 of township 19 north, range 99 west Mountain Gas Resources gathers gas from area pipelines and removes the natural gas liquids. The plant went on line in 1961. No hydrogen sulfide is present at either gas plant.

UNDERGROUND GAS STORAGE

Produced gas can be stored in some existing good quality reservoirs that have already been depleted of their native gas content. The objective of gas storage is to allow lands to be used to store natural gas during periods of excess production so that those supplies can be made available to meet peak gas demands and to maximize the efficiency of the gas delivery system. At Brady Field (Figure 22b) gas was stored in the Weber Sandstone beginning in 1976, but injection has terminated. There no other active or inactive gas storage projects within the Planning Area (Wyoming Oil and Gas Conservation Commission, 2012).

U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED TECHNICALLY RECOVERABLE OIL AND GAS RESOURCES

The U.S. Geological Survey has published a number of resource assessments of undiscovered technically recoverable oil and gas resources (See Glossary for undiscovered technically recoverable resource) that cover parts of the Planning Area. Their "1995 National Assessment of United States Oil and Gas Resources" (Law, 1995) scientifically estimated the amount of crude oil, natural gas, and natural gas liquids (see Glossary) 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. One of those provinces, the Southwestern Wyoming Province, exists in the Study Area (Figure 25).

Recently the U.S. Geological Survey revised their methods for preparing oil and gas resource assessments. Thirty two basins have been reassessed since the 1995 report (U.S. Geological Survey National Assessment, 2011). The U.S. Geological Survey used the new method to update their quantitative estimate of undiscovered technically recoverable oil and gas resource for the Southwestern Wyoming Province (Kirschbaum *et al.*, 2002). The updated 2002 Southwestern Wyoming Province assessment is summarized below with information about the geology, assessment units, and the potential undiscovered technically recoverable oil and gas resources lying within the Study Area. The northeast area of the Study Area was not assessed by the USGS because the Wind River Mountains cover this area. The acquisition of all information was from the U.S. Geological Survey Assessments. More information can be found on the U.S. Geological Survey National Oil and Gas Assessment website. Please refer to the complete reports published by the U.S. Geological Survey.

The Southwestern Wyoming Province is the only province in the Planning Area (Figure 25). It occupies 39,828,755.18 acres in the Planning Area. The Planning Area lies in the central portion of the province (Figure 25). The Southwestern Wyoming Province is located in southwest Wyoming, northwest Colorado, and northeast Utah. Geological features bounding the province are the Wyoming Thrust Belt (west boundary), Wind River Mountains and Granite Mountains (north boundary), Rawlins Uplift, Sierra Madres, and Park Range (east boundary), and the Axial Basin Uplift and Uinta Mountains (south boundary) (Kirschbaum *et al.*, Cpt. 1, Figure 1, 2002). Significant geologic features within the Southwestern Wyoming Province include the Moxa Arch, La Barge platform, Hoback Basin, Pinedale Anticline, Green River Basin, Rock Springs Uplift, Washakie Basin, Cherokee ridge, Sand Wash Basin, Wamsutter Arch, and the Great Divide Basin. The whole province defines the Greater Green River Basin (Kirschbaum, Chpt. 2, 2002).

The main sedimentary events include a shelf deposition, foreland deposition, and intrabasinal deposition which formed the thick stratigraphic sequence in the province

(Law, 1999). The U.S. Geological Survey denoted that Triassic and Jurassic rocks do not contain significant source rocks (Kirschbaum, Chpt. 3, 2002). Interfingering of shale, sand, and silt occurs throughout Cretaceous rocks (2002). Maximum sedimentary thickness in the province is 32,000 feet (Law, 1999). Structural influences in the basin are primarily from Laramide or pre-Laramide deformation (Law, 1999).

The top ten most active conventional-type operators in the Planning Area have been Wexpro Company, Anadarko E & P Company, Mountain Fuel Supply, Cabot Oil and Gas Corporation, Encana Oil and Gas Corporation, Forest Oil Corporation, Davis Oil Company, Texaco Incorporated, Luff Kenneth Incorporated, and Amoco Production Company. The top ten conventional fields in the Planning Area are Patrick Draw (1959), Fontenelle (1974), Jonah (1977), Lincoln Road (1977), Canyon Creek (1941), Table Rock (1946), Bird Canyon (1971), Trail (1958), Desert Springs (1958), and wildcat fields. Primary targeted formations are the Cretaceous Frontier Formation, Cretaceous Almond Formation, Cretaceous Mesaverde Group, Cretaceous Dakota Sandstone, Cretaceous Ericson Formation, Cretaceous Lance Formation, Jurassic Morrison Formation, Cretaceous Lewis Shale, Jurassic Nugget Sandstone, and the Cretaceous Baxter Shale (Wyoming Oil and Gas Conservation Commission, 2012 and IHS Energy Group, 2012).

The most active coalbed natural gas operators in the Planning Area are Warren E&P Incorporated; Infinity Oil and Gas, Incorporated ; Anadarko E&P Company; and Kennedy Oil Company, Incorporated. Primary formations targeted are the Cretaceous Almond Formation, Cretaceous Mesaverde Group, Tertiary Fort Union Formation, Cretaceous Rock Springs Formation, and the Cretaceous Lance Formation (Wyoming Oil and Gas Conservation Commission, 2012 and IHS Energy Group, 2012).

PLAY SUMMARIES

A “1995 National Assessment of United States Oil and Gas Resources” was completed for the Southwest Wyoming Province (Law, 1995). The 1995 assessment included the following ten conventional plays: Rock Springs Uplift play, Cherokee Arch play, Axial Uplift play, Moxa Arch-La Barge play, Basin Margin Anticline play, Subthrust play (hypothetical), Platform play, Jackson Hole play (hypothetical), and the Deep Basin Structural play (hypothetical). Unconventional plays included the Greater Green River Basin-Cloverly-Frontier play (hypothetical), Greater Green River Basin-Mesaverde play (hypothetical), Greater Green River Basin-Lewis play (hypothetical), Greater Green River Basin-Fox Hills-Lance play (hypothetical), and the Greater Green River Basin-Fort Union play (hypothetical). High water production in coalbed natural gas development was a significant problem at the time of the report. Poor water quality was also a problem in the coalbed gas play in the area (Cook *et al.*, 2002). Coalbed gas plays included the Greater Green River Basin-Rock Springs play, Greater Green River Basin Iles play, Greater Green River Basin-Williams Fork play, Greater Green River Basin-Almond play, Greater Green River Basin-Lance play, and the Greater Green River Basin-Fort Union play.

The 1995 assessment divided the Southwestern Wyoming province into "play" areas. Each play area (See Glossary for play area) is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play by "the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects." A conventional play will contain oil and gas accumulations having hydrocarbon-water contacts (due to the buoyancy of hydrocarbons in water) and seals that hold or trap the hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. An unconventional play will not have a hydrocarbon-water contact, will likely be close to or produce from source rocks, will not necessarily be associated with a structure or stratigraphic trap, and will require innovative technology to develop the play. Unconventional plays include coalbed natural gas, tight sands, oil shale, basin-centered gas, shale gas, tight oil, and methane hydrates (Kirschbaum *et al.*, Chapter 2, 2002). Supporting geologic studies for these play areas are available at Law (1995).

Dyman *et al.* (1997) showed that the Green River Basin Province contains sedimentary rocks at depths greater than 15,000 feet. Productive reservoir sediments are known in these rocks at depths below 15,000 feet (see previous discussion). The U.S. Geological Survey has not made a recent estimate of the potential petroleum resource at these depths. The Potential Gas Committee (2003) did estimate that most likely resources of natural gas below 15,000 in the Greater Green River Basin were 979 billion cubic feet of probable, 5.696 trillion cubic feet of possible, and 1.684 trillion cubic feet of speculative.

ASSESSMNENT UNIT SUMMARIES

In their newest assessment, the U.S. Geological Survey (2002) divided the Southwestern Wyoming Province into "total petroleum systems" and "assessment units" (see Glossary definitions) rather than "plays". The total petroleum system is a well-rounded approach focusing on the system as a whole. A total petroleum system is a "mappable entity encompassing genetically related petroleum that occurs in seeps, shows, and accumulations (discovered or undiscovered) that have been generated by a pod or by closely related pods of mature source rock" (Kirschbaum *et al.*, Chapter 2, 2002). An assessment unit is a "mappable volume of rock within a total petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic characteristics and may be identified as conventional or continuous accumulations" (2002). Essentially, a total petroleum system is the whole picture while an assessment unit is a detail of that picture.

Total Petroleum Systems in the Planning Area are split into conventional and continuous systems. Conventional total petroleum systems include the Phosphoria, Mowry Composite, Hilliard-Baxter-Mancos, Mesaverde, Mesaverde-Lance-Fort Union Composite, Lewis, Lance-Fort Union Composite. Continuous total petroleum systems include the Mowry Composite, Niobrara, Hilliard-Baxter-Mancos, Mesaverde, Mesaverde-Lance-Fort Union, Lewis, Lance-Fort Union Composite, and the Wasatch-

Green River Composite. Each total petroleum system has assessment units that make up the total petroleum system.

Conventional oil and gas assessment units in the Planning Area include the Sub-Cretaceous Conventional Oil and Gas in the Phosphoria total petroleum system (Figure 26), Mowry Conventional Oil and Gas in the Mowry composite total petroleum system (Figure 27), Hilliard-Baxter-Mancos Conventional Oil and Gas in the Hilliard-Baxter Mancos total petroleum system (Figure 28), Mesaverde Conventional Oil and Gas in the Mesaverde total petroleum system (Figure 29), Mesaverde-Lance-Fort Union Conventional Oil and Gas in the Mesaverde-Lance-Fort union composite total petroleum system (Figure 30, Lewis Conventional Oil and Gas in the Lewis total petroleum system (Figure 31), and Lance-Fort Union Conventional Oil and Gas in the Lance-Fort Union total petroleum system (Figure 32).

Continuous oil and gas assessment units in the Planning Area include the Mowry Continuous Gas in the Mowry composite total petroleum system (Figure 33); Niobrara Continuous Gas in the Niobrara total petroleum system (Figure 34); Hilliard-Baxter-Mancos Continuous Gas in the Hilliard-Baxter-Mancos total petroleum system (Figure 35); Almond Continuous Gas, Rock Springs-Ericson Continuous Gas, and Mesaverde Coalbed Gas in the Mesaverde total petroleum system (Figure 36); Mesaverde-Lance-Fort Union Continuous Gas, Fort Union Coalbed Gas, and Mesaverde Coalbed Gas in the Mesaverde-Lance-Fort Union composite total petroleum system (Figure 37); Lewis Continuous Gas in the Lewis total petroleum system (Figure 38); Lance-Fort Union Continuous Gas, Lance Coalbed Gas, and Fort Union Coalbed Gas in the Lance-Fort Union composite total petroleum system (Figure 39); and Wasatch-Green River Continuous Gas, and Wasatch-Green River Coalbed Gas in Wasatch-Green river composite total petroleum system (Figure 40).

As stated above, the 1995 assessment was reanalyzed and new areas were defined based on assessment unit standards instead of play area standards. The 2002 assessment information was used for this report. The U.S. Geological Survey has made available some statistical information for these assessment units (Tables 8 and 9). Supporting geologic studies for these assessment units are available at Kirschbaum, *et al.*, (2002).

ASSESSMNENT UNIT AND PLAY RESOURCE RESULTS

The U.S. Geological Survey (2002 and 2005) 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, is a summary of the estimated volumes of hydrocarbons in the 22 assessment units, which lie at least partly within the Planning Area.

Table 10 shows the U.S. Geological Survey resource estimates for three types of hydrocarbons (oil, gas, and natural gas liquids) for conventional and continuous assessment units in the Southwestern Wyoming Province. Table 10 also shows this report's projection of the amount of those hydrocarbons that could be present within the Planning Area. To determine the potential resource within the Planning Area three steps were taken:

- Assumed a homogenous distribution of each hydrocarbon type within each assessment unit or play area,
- Calculated the percent of each assessment unit or play area that lies within the Planning Area, and
- Multiplied that percentage by the U.S. Geological Survey resource value estimates for each entire assessment unit or play area to calculate Planning Area resource values.

This report's estimates of recoverable resources for each assessment unit within the province and within the Planning Area are presented as a range of possibilities: a low case having a 95 percent probability of that amount or more occurring, a high case having a five percent probability of that amount or more occurring, and a mean case representing an arithmetic average of all possible outcomes. Estimates of resources within the Planning Area are: a **mean undiscovered volume of 23.82 million barrels of oil, 29,274.51 billion cubic feet of gas, and 1,120.09 million barrels of natural gas liquids, in the Southwestern Wyoming Province assessment units (Table 10).**

In addition, the estimate of oil resource in the Southwestern Wyoming Province is that it could **range from 5.92 to 58.57 million barrels, the gas resource could range from 17,067.27 to 47,083.44 billion cubic feet, and the natural gas liquids resource could range from 511.36 to 2,078.16 million barrels (Table 10).**

DEPARTMENSTS OF INTERIOR, AGRICULTURE, AND ENERGY RESOURCE ASSESSMENTS

The U.S. Departments of Interior, Agriculture, and Energy (2003, 2006, and 2008) have contributed to three publications that inventoried oil and gas resources in parts of the Rocky Mountains. 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.

RAND SCIENCE AND TECHNOLOGY RESOURCE 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. I 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. Therefore, their analysis methodology has not been used to analyze the Planning Area.

STATE OF WYOMING RESOURCE ASSESSMENT

The Jack Morrow Hills and surrounding areas were studied by the Wyoming State Geological Survey in 2002 (Cook *et al.*, 2002). Their report discussed the geology of the area, conventional and continuous accumulations (including tight sands and coalbed natural gas), and production. Tertiary and Cretaceous geologic formations were primary hydrocarbon targets, along with the Mississippian Madison Limestone. Analysis of production and risk assessment were reviewed for resource estimates. In 2000, the Jack Morrow Hills area had cumulatively produced "8 million barrels of oil (MMBO) and 1 trillion cubic feet (TCF) of gas" (Cook *et al.*, 2002). Future technology, including the need to hydraulically fracture wells in the area, horizontally drill formations, and acquire three-dimensional seismic data was addressed. Price forecasting was also discussed. The normal price of oil was assumed to be $20 to $25 per barrel and for gas it was $2.25 to $2.75 per thousand cubic feet (2002). Total hydrocarbon resource potential for the area was estimated to be 430.2 trillion cubic feet of natural gas and 8.4 million barrels of oil. Please see the report for additional details.

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 Planning 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 USGS [United States Geological Survey] national assessment, or, in the absence of play designation by the USGS, 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, I consider that all Planning Area lands within the Southwestern Wyoming Province (U.S. Geological Survey, 2002) have a high potential for the occurrence of conventional types of oil and gas (Figure 41). Coalbed natural gas is excluded from this map. All areas within the Southwestern Wyoming Province are contained within specific conventional or continuous assessment units (excluding coalbed natural gas assessment units) designated by the U.S. Geological Survey (2002) so are considered to have high potential. The Wind River Mountains (an area of granitic type rocks) was assigned a low potential since source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and/or traps may not be present.

Occurrence potential for coalbed natural gas was assigned a high, low, or none value on Figure 42. Areas designated as high occurrence potential lie within Southwestern Wyoming Province coalbed natural gas assessment units (U.S. Geological Survey, 2002). Since they occupy specific coalbed natural gas assessment units they meet the criteria for high occurrence potential. Areas of low potential are still contained within the Southwestern Wyoming Province but may not include all the criteria listed above to contain coalbed natural gas resources. The area of the Wind River Mountains outside the Southwestern Wyoming Province does not contain coal beds so does not meet the criteria of having reservoir rocks present and thus was assigned an occurrence potential of none.

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2012-2031

The Annual Energy Outlook 2011, written by the Energy Information Administration, focuses on the factors that shape the U. S. energy system over the long term. Key results highlighted in the Annual Energy Outlook 2011 include:

• Strong growth in shale gas production. Shale gas production continues to increase strongly in the Annual Energy Outlook 2011 reference case, growing almost fourfold from 2009 to 2035. Shale gas production grows to 12.2 trillion cubic feet in 2035, when it makes up 47 percent of total U.S. production—up considerably from the 16 percent share in 2009.

• Growing use of natural gas and renewables in electric power generation. The role of natural gas in power generation grows due to low natural gas prices and the relatively low capital costs for new natural gas plants that make it more attractive than coal. The share of generation of power from natural gas increases from 23 percent in 2009 to 25 percent in 2035.

• Declining reliance on imported liquid fuels. Although U. S. consumption of liquid fuels continues to grow through 2035, reliance on petroleum imports as a share of total liquids consumption decreases. Total U.S. consumption of liquid fuels rises from about 18.8 million barrels per day in 2009 to 21.9 million barrels per day in 2035. The import share which reached 60 percent in 2005 falls to 42 percent in 2035. Rising fuel prices spur domestic energy production across all fuels.

The above projected increases in demand and in oil and gas prices indicate continued industry emphasis on increasing natural gas supplies and searching for additional oil supplies in the Rock Springs Planning Area. The combination of horizontal drilling and hydraulic fracturing technologies has made it possible to produce shale gas, tight oil, and tight gas economically. Much of the Planning Area oil and gas supply growth is expected to come from production from existing reservoirs, with most of the new reservoir discoveries potentially coming from exploration for nonconventional plays in the continuous assessment units identified by the U.S. Geological Survey (2002 and 2005).

OIL AND GAS PRICE ESTIMATES

Anticipated oil and gas prices are an important factor controlling the amount of future drilling and production activity in the Planning Area. Kaiser (2012) reported that "unconventional gas resources are abundant, but their development is particularly sensitive to technologic risk, geologic uncertainty, and gas price". Conventional plays in 2010 reportedly had an operational costs break-even price of $3-4 per thousand cubic feet (Schaefer, 2010). The National Petroleum Council (2011) stated "Significant technology advances have unlocked abundant natural gas and oil resources, but the potential benefits can only be realized if developed prudently."

Gas Prices

In 1996, natural gas prices in Wyoming started on a general increase. Several peaks and valleys in the price trend have occurred since that time, but by 2005, prices had increased to an average of $7.43 per thousand cubic feet. Wyoming wellhead prices declined sharply from 2005 to 2007 ($4.57 per thousand cubic feet), peaking again in 2008. As world economies struggled in 2009, Wyoming wellhead gas prices fell to $3.20 per thousand cubic feet. In recent months gas prices have fallen below $3 per thousand cubic feet. "Natural gas in the New York market slipped further below $2.50/MMBTU (See Glossary for BTU), and given the more mild weather forecasts, we don't expect this to improve much anytime soon" (Raymond James, 2012).

Data for Figure 43 (historical and projected future natural gas prices) were obtained from the Energy Information Administration (2011). In the Annual Energy Outlook 2012 (Lower 48), average annual wellhead prices for natural gas remain below $5 per thousand cubic feet (nominal dollars) through 2017. The projected prices reflect continued industry success in tapping the Nation's extensive shale gas resource. Natural gas prices rise as production gradually shifts to resources that are less productive and more expensive. Natural gas wellhead prices (nominal dollars) reach $10.24 per thousand cubic feet in 2035. The forecasted natural gas price using 2009 dollars is $6.42 per thousand cubic feet in 2035.

The natural gas price projections allow for some generalizations concerning future gas drilling and production activity in the Rock Springs Planning Area. For the short term, the interest in natural gas exploration in the Rock Springs area will likely continue or decrease since prices dropped sharply in 2011 and 2012. Similarly, recent interest in new exploration of potential gas plays may be curtailed by low gas prices. Assuming a general upward trend in future wellhead natural gas prices, the level of drilling activity in the Planning Area will probably be driven more by the success of exploratory drilling efforts, horizontal drilling, and fracture technology. The resilience of drilling levels, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have high concentrations of crude oil, condensates, or natural gas liquids.

Increases in future natural gas production to accommodate projected increased demand is anticipated to come partly from the Rocky Mountain area, in particular shale gas resources. It is difficult to predict how much new gas production is expected to come from reservoirs in the Planning Area. Industry has shown recent interest in shale gas resources and unconventional plays in the Hiawatha area. Operators plan to continue drilling wells in existing fields in the La Barge area and south of the Jonah field with up to 150 wells per township planned. There is also considerable activity planned in the Bridger area on conventional plays. Very little coalbed natural activity is planned in the Planning Area. Any additional gas produced from Planning Area plays is expected to come mainly from the limited expansion and infill of existing gas plays, the exploration and development of new shale gas, and discoveries in the Hiawatha area. If the shale gas plays prove successful in the Planning Area, gas drilling will likely increase to levels not yet experienced in the Planning Area. Horizontal well drilling rates will also increase.

Projecting future gas drilling rates following hypothetical new discoveries is not possible at this time.

Oil Prices

U.S. energy demand and economic activity in 2012 will gain some momentum from last year's doldrums but growth for each will remain anemic (Radler, 2012). Total energy demand will increase by 1.2% in the U. S., according to Oil & Gas Journal's annual Forecast & Review. Early estimates indicate that in 2011 demand climbed by a mere 0.3%. But uncertainties abound this year—from the state of the European Union and its economies weakened by debt defaults to the effect of the West's reactions to Iran's development of nuclear capabilities—and it's those uncertainties that will drive the 2012 oil market.

Data for Figure 44 (historical and projected crude oil prices) were obtained from the Energy Information Administration (2011). The data are projected averages of low sulfur light crude oil prices and are made in nominal dollars. Historical prices represent the actual average price at the wellhead and show the historic volatility that has occurred in crude oil prices in Wyoming. Prices began declining in the early 1980's from a high of $35.69 in 1981 to a low of $12.56 in 1998. A significant climb is seen in oil prices starting in 1999 up to 2008. The rise from a low of $12.56 per barrel to the most recent average high of nearly $100 per barrel represents nearly an order of magnitude increase in prices in just eleven years.

Prices for crude oil in 2011 remained generally in a range between $74 and $100 per barrel. Low sulfur light crude oil prices (nominal dollars) in the Annual Energy Outlook rise to $125 per barrel in 2019 as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil is about $125 per barrel in 2009 dollars, or about $200 per barrel in nominal dollars.

The Annual Energy Outlook assumes that limitations on access to energy resources restrain the growth of non-OPEC conventional liquids production between 2012 and 2035, and that OPEC targets a relatively constant market share of total world liquids production. There is a wide range of price scenarios and a great deal of uncertainty surrounding future world oil prices. In several resource rich regions, high oil prices, oil sands, expanded infrastructure, further investment in exploration and drilling contribute to additional non-OPEC oil production.

The future gas drilling target areas discussed in the above "Gas Prices" discussion will generally also produce condensate in association with the gas production. In addition, more oil drilling will take place as the Monell, Arch, and Table Rock units (Figure 10) are further developed.

LEASING

After initial fieldwork, research, and subsurface mapping (which frequently includes use of seismic date), leasing is often the next step in oil and gas development. Leasing may be based on speculation, with leases within high risk prospects usually purchased for the lowest prices.

Leases on lands where the United States owns the oil and gas rights are offered via oral auction at least quarterly. A list of parcels that will be offered for lease, plus their associated environmental stipulations, is published in a "Notice of Competitive Oil and Gas Lease Sale" which is posted at least 45 days prior to the date of each sale. Leasing is a discretionary act of the Secretary of Interior. Parcels offered for lease may be withdrawn at any time prior to lease issuance.

Maximum lease size is 2,560 acres and the minimum bid is two dollars per acre. A $365 dollar per parcel administrative fee 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 of the lease and two dollar per acre is charged thereafter. Leases are issued for a ten-year term and a 12.5 percent royalty on any production is required. Leases that become productive are held-by-production and normally do not terminate until all wells on the lease have ceased production. Many private oil and gas leases contain a "Pugh clause," which allows only the developed portion of the lease to be held by production. However, Federal leases have no such clause, allowing one well to hold an entire lease.

In Wyoming, Federal oil and gas lease sales are now held four times a year (February, May, August, and November), usually in Cheyenne, Wyoming. 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 is reviewed for resource conflicts and contains restrictive stipulations which protect potentially affected, mainly surface resource values.

Oil and gas prices and exploration success will to a great extent, determine the amount of acreage lease and bonus bids received. Forty-nine percent of the money earned from oil and gas leases on public domain (See Glossary for public domain) minerals goes to the State of Wyoming. 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 45 presents the locations of leased and unleased Federal oil and gas minerals within the Planning Area. Excluding lands under Bureau Wilderness Planning Areas, there are about 3,532,951 acres of Federal oil and gas minerals. About 97 percent of all Wilderness Study Areas shown in Figure 45 contain Federal oil and gas minerals. Bureau records indicate that there were about 1,459,381 acres of leased oil and gas Federal mineral acres (as of October 1, 2012) and 2,073,570 of unleased Federal oil and gas minerals (including most of the 229,215 acres of Wilderness Study Areas). About 41 percent of Federal oil and gas minerals were leased at that time.

Leasing often can be one of the first indications of a developing play in a region. After initial scientific investigations and perhaps preliminary drilling has occurred, leasing over a relatively large area is the next logical step in development of an oil and gas play. Lease sales in the Rock Springs Planning Area in 2011 occurred only during November. Lease bonus varied from approximately $20 per acre to $150 per acre. These amounts compare to bids of $3,000 to $7,000 per acre for lands in Converse County, Wyoming. The lease sales were held mainly in the Hiawatha area and in the east flank of the Moxa Arch. Sales planned for 2012 are in the Jack Morrow Hills area, the La Barge area, and in the area west of Flaming Gorge Reservoir.

PROJECTIONS OF FUTURE OIL AND GAS 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 Planning Area, geologists and engineers in the oil and gas industry were approached for their input. Major oil and gas companies operating in the Planning 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. Information obtained was compiled and used to help predict locations and amounts of future drilling activity within the Planning Area. A review of available technical data was also used to help make these predictions. Much of the data reviewed has been summarized above.

Projected Conventional Oil and Gas Drilling Activity

For a base line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2002, page 13) I estimate that during the 20-year planning cycle of 2012 to 2031, as many as 6,333 wells will be drilled in the Planning Area. Of these wells, 6,095 are projected to be conventional oil and gas wells and 238 are projected to be coalbed natural gas wells. In the twenty-year period between 1992 and 2012 operators drilled 25 deep wells (greater than 15,000 feet in depth) and there are currently no proposals to drill additional deep wells. As many as 15 to 50 of the 6,095 conventional wells could be deep wells and they could be located just about anywhere within the Planning Area, with the exception of the Wind River Mountains on the northeast. As such development is at this point hypothetical, no provisions were made in this report's calculations to include additional disturbance from deep wells (all conventional wells were treated the same for surface disturbance calculations).

The estimated conventional oil and gas development potential and drilling densities within the Planning Area during the Analysis Period are shown in Figure 46. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 46 are summarized in Table 11a. The same calculations were made for Federal oil and gas minerals and are presented in Table 11b.

Conventional oil and gas development potential is defined as very high, high, moderate, low, very low, and none. I estimate that **average** drilling densities per township (one township is about 36 square miles) during the Analysis Period will be:

- Very High: more than 150 wells
- High 50 to 150 wells
- Moderate: 20 to less than 50 wells
- Low: 5 to less than 20 wells
- Very Low: less than 5 wells
- None no wells

Bureau wilderness study areas were not assessed for future development potential since those areas cover Federal lands that are removed from oil and gas leasing and thus, oil and gas development cannot occur.

Areas of development potential rated none are only located in the northeast part of the Planning Area where the U.S. Geological Survey (2002 and 2005) did not include the Wind River Mountains within the Southwestern Wyoming Province. A limited number of conventional wells (about five percent of the total) could be drilled in areas of very low development potential and are projected for areas generally not proven productive by historical drilling, but which still may contain hydrocarbons based on U.S. Geological Survey assessment data. Most of these townships will not receive any drilling at all. If new field discoveries are made in any of these areas of very low development potential, subsequent drilling density could increase in those specific areas. However, predicting a well density for such areas is not possible at this time.

Areas of very high, high, moderate, and low conventional development potential have future operator interest and/or have had historical oil and gas exploration and/or development activity that has indicated the presence of hydrocarbons that is or may be economic to produce.

During the last 10 years the average conventional well depth has been 5,264 feet and the median has been about 8,820 feet. Future average drilling depths are expected to increase with the median being in the range of 8,800 to 9,800 feet. In addition, the rate of horizontal well drilling is expected to increase.

The majority of the anticipated activity in the Planning Area is expected to be infill drilling of conventional wells to increase proved recoverable reserves and as exploratory drilling to further explore for conventional resources and potential continuous resources identified by the U.S. Geological Survey (2002 and 2005) for the Southwestern Wyoming Province. Initial estimates of the ultimate size of new oil or gas fields are usually too low, and over time, newer estimates of the size and ultimate recovery contribute to growth in the reserve estimate (Central Region Energy Resources Team, 1996). Factors that could contribute to increases in reserve growth in the Planning Area 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 Activity

For a base line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2002, page 13) I estimate that during the 20-year planning cycle of 2012 to 2031, as many as 238 coalbed natural gas wells are projected to be drilled. The estimated coalbed natural gas development potential and drilling densities within the Planning Area during the Analysis Period are shown in Figure 47. Estimated acres, number of townships, and percentage of the Planning Area within each development potential classification type shown in Figure 47 are summarized in Table 12a. The same calculations were made for Federal oil and gas minerals and are presented in Table 12b.

Coalbed natural gas development potential for this analysis is defined as moderate, low, very low, and none. The results of reviewing operator's submissions and historic coalbed natural gas activity levels in the Planning Area did not warrant assigning any higher potential category levels. I estimate that **average** drilling densities per township (one township is about 36 square miles) during the Analysis Period will be:

- Moderate: greater than 10 to 30 wells
- Low: 2 to 10 wells
- Very Low: less than 2 wells
- None no wells

Again, Bureau wilderness study areas were not assessed for future development potential since those areas cover Federal lands that are removed from oil and gas leasing and thus, oil and gas development cannot occur.

Areas of development potential rated none are those that the U.S. Geological Survey (2002 and 2005) did not include in any coalbed natural gas assessment units and the Wind River Mountains on the northeast. Very little interest in additional coalbed natural gas drilling was indicated by active operators in the Planning Area. Moderate and low development potential areas (Figure 47) outline parts of the Planning Area where concentrations of productive wells are or have been located (Figure 15). Very low development potential areas have had scattered coalbed natural gas well tests. Additional exploratory activity could occur in the very low development potential area, but most of these townships will not receive any drilling at all. If new field discoveries are made in any of these areas of very low development potential, subsequent drilling density could increase in those specific areas. However, predicting a well density for such areas is not possible at this time.

The low projection of future coalbed natural gas drilling appear to be tied to problems associated with high rates of water production and low rates of gas production and with

water disposal issues in the Planning Area. If these issues are not resolved during the Analysis Period then most of the coalbed natural gas wells projected will not get drilled.

During the short life of the coalbed natural gas drilling play in the Planning Area (1989 to present) the average well depth has been close to 4,000 feet. Producing intervals have been between 1,000 feet and 6,000 feet and the future range is expected to remain in the historical range.

PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION

The decline in annual crude oil production from Wyoming (Figure 48) reversed itself in 2006 and production increased in both 2010 and 2011 (Energy Information Administration, 2012b). This change is partly tied to increased enhanced oil recovery associated with carbon dioxide injection and partly tied to higher crude oil prices (Figure 44). Natural gas production from Wyoming (Figure 49) had grown steadily in recent years, but declined in both 2010 and 2011(Energy Information Administration, 2012c). Much of this growth has been from unconventional resources, although conventional production has also been increasing. The recent decline in production appears to be tied to recent declines in natural gas prices (Figure 43).

ESTIMATED FUTURE PRODUCTION

As indicated above, I projected 6,095 conventional oil and gas wells and 238 coalbed natural wells could be drilled within the Analysis Period of 2012 through 2031. Table 13 presents a forecast of conventional oil and gas production for the 20-year Analysis Period and a forecast of coalbed natural gas production. All three types of hydrocarbon production are expected to increase over the Analysis Period. If the projected wells are not drilled at the analyzed rate or are not drilled at all, these production rates will not be achieved.

OTHER POTENTIAL FUTURE OIL AND GAS ACTIVITIES

Shale Gas

The Hilliard-Baxter Mancos continuous resource assessment unit identified by the U.S. Geological Survey (2002 and 2005) has been identified as a potential shale gas resource in the Planning Area. About 77 percent of the assessment unit lies within the Planning Area (Table 10). Within the Planning Area the estimated total undiscovered resource ranges from 3.77 to 17.49 trillion cubic feet of gas and a mean of 9.05 trillion cubic feet of gas. In 2008, five companies holding leases in this shale play were Anadarko Petroleum, Devon Energy, Kodiak Oil and Gas, Questar, and Ultra Petroleum (Energy Information Administration, 2011b).

If a shale gas play aerially overlaps an existing play, existing boreholes may also be utilized in addition to new wells drilled specifically for the shale gas. However, the nature of shale gas plays would likely require drilling of horizontal wells, so the existing

boreholes would likely still have to be re-entered and a horizontal lateral drilled into the zone of interest using the existing borehole as a pilot. Shale has very low permeability and large hydraulic fracture stimulations will probably be necessary to liberate the gas (Bereskin and Mavor, 2003). Production may be accompanied by significant volumes of water. 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.

Coal Gasification

Underground coal gasification may be a potential future process that is applied to coal deposits within the Planning Area. This process burns the coal in-situ producing a combustible gas with a low heating value that can be used in industrial processes, in gas turbines, and can be converted to electrical power. 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 evidence that combustion gases preferentially absorb to the coal cleat faces and displace coalbed natural gas from the coal, which increases the heating value of the produced gas. The heat of reaction of the burned coal heats up 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 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 (generally greater than 500 feet). 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, greater depths, and strong cap rocks in the Planning Area should limit this.

DKRW Advanced Fuels of Houston, plan to build a plant to turn coal into gasoline by 2016. The plant will be built in Carbon County, Wyoming to the east of the Planning Area. If the project is able to show that underground gasification technology involving deep coal beds is economic then additional projects could be proposed at within the Planning Area. Any projects on Bureau managed minerals would likely only occur near the end of the Analysis Period and then only if the process is first proved to be economic.

Carbon Dioxide Sequestration

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas, a greenhouse gas. Power plants, ethanol plants, and petroleum and natural gas processing

facilities (including refineries and sources associated with pipeline infrastructure), cement and lime plants, agricultural processing facilities, industrial facilities, iron and steel production facilities, and fertilizer producing facilities have been identified as the primary stationary carbon dioxide sources (United States Department of Energy, 2010). Of these sources, electrical power plants produce the most carbon dioxide by a substantial margin.

Within the Planning Area the largest stationary source of carbon dioxide is from output of the Jim Bridger coal fired electrical generation plant east of the town of Rock Springs. Other main stationary sources are associated with petroleum and natural gas processing facilities within the Planning Area.

Capturing and storing carbon dioxide has been proposed to reduce the environmental effects caused by releasing the gas to the atmosphere. Three types of geologic formations have been identified as potential carbon dioxide sequestrations sites, each occurring in the Planning Area (United States Department of Energy, 2010). 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 nonpotable. In Wyoming about 2,300 million metric tons of carbon dioxide could be stored in these reservoirs (United States Department of Energy, 2010). At present the Monell unit is being used to enhance oil recovery and store carbon dioxide (see previous discussion "carbon dioxide injection". There are plans for similar type project at the nearby Arch unit, with a pilot study occurring first and then full development if the pilot is successful. There are no other plans for this type of project in the Planning Area.
- Unmineable coal seams – Unmineable coal seams are considered to be those that are too deep or too thin to be economically mined. The storage resource in unmineable coal in Wyoming is projected to be between 11,860 and 12,140 million metric tons (United States Department of Energy, 2010). The majority of the Tertiary and Cretaceous coals in the Planning Area meet these criteria. During carbon dioxide storage those molecules displace methane molecules that are present. If methane displaced by carbon dioxide storage can make the process economic to pursue 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. Feasibility studies have looked at coal beds in other parts of Wyoming, but no pilot projects have been approved.
- Saline formations – Saline formations suitable for carbon sequestration were defined in the United States Department of Energy (2010) atlas as porous and permeable rocks containing water with total dissolved solids greater than 10,000 milligrams per liter, which have the capacity to store large volumes of carbon dioxide. They are much more extensive than coal seams or oil- and gas-bearing rock, 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. The storage resource in saline formations in Wyoming is projected to be between 87,430 and 1,202,200 million metric tons (United States Department of Energy, 2010). The Carbon Management Institute (2012) at the University of Wyoming is currently engaged in research and development related to carbon dioxide storage. The Institute is presently studying two potential carbon storage reservoirs (the Weber Sandstone and the Madison Limestone) on the Rock Springs Uplift within the Planning Area. They spudded a test of these formations (section 16 of township 20 north, range 101 west: see Figure 22b) in June of 2011 and reached a total depth of 12,810 feet. Additional study of the well is ongoing. The Institute has projected that the two reservoirs could store as much as 26 billion tons of carbon dioxide.

REASONABLLY FORESEEABLE DEVELOPMENT SCENARIOS FOR RESOURCE MANAGEMENT PLAN ALTERNATIVES A, B, AND C

The Draft Environmental Impact Statement for the Rock Springs Planning Area Resource Management Plan contains three management alternatives. Each alternative contains management imposed restrictions that may negatively affect oil and gas development. These restrictions can effectively decrease the base line estimated number of well locations in areas of Federal oil and gas ownership. For each alternative, I have analyzed the restrictions and estimated the number of resulting well locations that could be reduced from the base line total.

PROCEDURES USED TO DETERMINE WELL LOCATION REDUCTIONS

Well location reductions from the base line reasonably foreseeable development scenario, for each alternative, are due to proposed management restrictions. Restrictions applied to each alternative can affect oil and gas development activities by not allowing leasing, not allowing surface occupancy, controlling surface use, or placing restrictive stipulations on conditions of approval of Federal applications to drill. In some cases they can also affect future drilling activities on other lands such as private and state oil and gas mineral ownership. Reduced oil and gas activities result in increased exploration and development costs, fewer drilled wells, and reduced production. For reasonably foreseeable development scenario analysis purposes, the restrictions for the three alternatives analyzed were separated into four categories designated A, B, C, and D. Restrictions on drilling are progressively more limiting from restriction category A to restriction category D and are:

- Restriction Category A - These areas are open to leasing. Restrictions are relatively minor and result in standard lease terms and conditions that are applied to every Federal oil and gas lease sold in Wyoming. These restrictions are

considered to have little to no effect on the number of future well locations or production for any alternative.

- Restriction Category B – These areas are open to leasing subject to relatively minor constraints. These restrictions can have a moderate effect such as multiple, consecutive timing restrictions for protection of wildlife values such as; crucial winter range, raptor nesting habitat, or sage grouse strutting grounds. I also considered restrictions such as avoidance of areas within wetlands, riparian areas, or perennial waters could have a moderate effect on the potential locations of future wells and cumulative production.
- Restriction Category C – These areas are open to leasing, subject to major constraints. These restrictions can have a moderate to severe effect on the location of wells; such as no surface occupancy stipulations on an area more than 40 acres in size or requirements that view sheds be protected, thus requiring that well locations and production facilities not be visible from areas such as historic trails. Overlapping minor constraints may also severely limit the future development of oil and gas resources.
- Restriction Category D areas are closed to leasing. These are areas where a determination is made that other land uses or resource values cannot be adequately protected with even the most restrictive lease stipulations. Because areas are closed to leasing, this category has the most severe restrictions on future oil and gas activity and production. Where lands are predominantly Bureau managed, there can also be a secondary effect on non-Bureau managed lands causing severe restrictions on future activity on these non-Bureau managed lands.

Estimates of future reductions in well locations from the base line reasonably foreseeable development projection were determined as described below:

- An estimate of the number of well locations/township (average well density) that could be drilled in each development potential category over the 20-year life of the Resource Management Plan was made for conventional oil and gas development activity and for coalbed gas development activity. The average conventional well density per township for very high development potential was projected to be 240 wells, for high development potential it was projected to be 100 wells, for moderate development potential it was projected to be 35 wells per township, for low development potential it was projected to be 12.5 wells per township, and for very low development potential it was projected to be 2.5 wells per township. The average coalbed natural gas well density per township for moderate development potential was projected to be 20 wells, for low development potential it was projected to be six wells, and for very low development potential is was projected to be one well.
- The acres of Bureau managed oil and gas ownership for each area of conventional development potential (Figure 46) was determined using GIS software. Resource Management Plan decisions will only apply to Bureau managed oil and gas minerals. In areas that are proposed for closure to oil and gas leasing of Bureau managed land I also projected some additional restriction in oil and gas activity on those non-Bureau lands. These addition reductions on non-Bureau lands are assumed to be a secondary effect caused by large surrounding areas of Bureau oil

and gas minerals being unavailable for leasing, thereby making these non-Bureau lands less attractive for future drilling activity. In areas proposed for closure to oil and gas leasing acres of non-Bureau managed oil and gas ownership were also calculated so that some additional activity restriction could be made.

- The acres of Bureau managed oil and gas ownership for each area of coalbed gas development potential (Figure 47) was determined using GIS software. Again, areas proposed for closure to oil and gas leasing of non-Bureau managed oil and gas ownership acres were also calculated (for the same reasons as indicated above) so that some additional activity restriction could be made.
- Next, the areas covered by each restriction category (B, C, or D) within the very high, high, moderate, low, or very low development potential areas for conventional oil and gas and moderate, low, and very low development potential areas for coalbed natural gas were calculated using GIS software. For category D (no leasing) acres were calculated for unleased Bureau and leased Bureau managed lands and for non-Bureau managed lands. The area within category A was not calculated, because we previously determined that this type of restriction would have no significant effect on the number of well locations for any alternative. As an example, the Alternative B acreage calculations for each potential area are presented in Table 14.
- After the acres of Bureau managed oil and gas were calculated for each alternative in each restriction category, the percent reduction in well locations for each alternative in each category of restriction was estimated. This estimate is a percent of the well locations which would not be drilled in each area due to the specific category of restriction. As an example, the results of my calculations for Alternative B, Category D (no leasing) restrictions are shown in Table 15 below.
- The percent reduction in well location for each alternative, each category of restriction, and each development potential combination was determined. The estimates of reduction in well locations were then summed for conventional oil and gas wells in all areas and for coalbed natural gas for each alternative. The reductions of Bureau and non-Bureau managed wells projected to be drilled for each alternative are subtracted from the base line analysis and are presented in Table 16.

ESTIMATED FUTURE OIL AND GAS PRODUCTION

Table 13 presents future oil and gas and coalbed natural gas production for the Analysis Period. Production projections were also made for each alternative (Alternative A – Table 17, Alternative B – Table 18, and Alternative C – Table 19) and reflect the adjusted percent of well count reductions presented for each alternative in Table 16.

POTENTIAL OIL AND GAS SURFACE DISTURBANCE

Table 20 projects short-term and long-term disturbance associated with existing conventional oil and gas wells and coalbed natural gas wells and projected drilling activity for both types of wells for 2012 through 2031. The method used to determine the

number of new wells drilled during this period has been previously discussed. In addition, I assumed that:

- of the 2,139 existing active conventional oil and gas wells, 15 percent will be abandoned by 2031,
- of the 52 existing active coalbed natural gas wells, all will be abandoned by 2031,
- the success rate of new conventional oil and gas wells will average 85 percent and 10 percent will be abandoned before the end of the Analysis Period based on historical trends, and
- the success rate of new coalbed natural gas wells will average 95 percent and 15 percent will be abandoned before the end of the Analysis Period based on historical trends.

Per pad estimated ranges of surface disturbance for new wells (including conventional and coalbed natural gas wells) are:

- 2 to 7 acres of initial pad disturbance
- 1 to 3.5 acres of initial road disturbance
- 0.5 to 2 acres of initial pipeline disturbance
- 1 to 3.5 acres long term pad disturbance for producing wells
- 0.75 to 2.5 acres of long term road disturbance for producing wells
- 0.25 to 1 acre of long term pipeline disturbance for producing wells

Average per pad disturbance (well pad plus associated roads plus associated pipelines) for the 85 percent of conventional oil and gas wells and 95 percent of coalbed natural gas wells that are initially completed as productive will be 7.10 acres. Average per pad disturbance (well pad plus associated roads) for wells that are immediately drilled and abandoned (15 percent of conventional wells and five percent of coalbed natural gas wells) will be 5.6 acres, since immediately abandoned wells do not require the installation of a pipeline.

During the Analysis Period it is expected that the percent of pads with more than one borehole drilled per pad will increase. Since it is not presently clear what the percent of multi-well pads will be this analysis assumes only one borehole per pad will be drilled. Any multi-well pads drilled in the future will average a larger disturbed area per pad but a smaller average disturbance per borehole drilled on each pad. This means if multi-well pads are drilled in the Planning Area in the future the projections of disturbance presented in Figure 14 will be reduced. If multi-well pads become common in the future, disturbance projections will be significantly reduced.

Table 20 shows the projection of new conventional exploratory and development wells (6,095 wells, with 4,997 of those wells managed by the Bureau) that could be drilled in the Planning Area from 2012 through 2031. There are an additional 2,259 existing active conventional wells (Wyoming Oil and Gas Conservation Commission, 2012), with 1,536 of those wells lying on Bureau managed oil and gas minerals. A total of 8,354 existing and projected conventional oil and gas wells (6,095 projected wells plus 2,259 existing wells) are projected for calculations of short-term disturbance, with 6,533 wells managed by the Bureau (4,997 projected wells plus 1,536 existing wells).

In addition, Table 20 shows the projection of new coalbed natural gas wells (238 wells with 158 of those wells managed by the Bureau) that could be drilled in the Planning Area from 2012 through 2031. There are an additional 52 existing active coalbed natural gas wells (Wyoming Oil and Gas Conservation Commission, 2012), with 28 of those wells lying on Bureau managed oil and gas minerals. A total of 290 existing and projected coalbed natural gas wells (238 projected wells plus 52 existing wells) are projected for calculations of short-term disturbance, with 186 wells managed by the Bureau (158 projected wells plus 28 existing wells).

Table 20 also calculates acres of total short-term surface disturbance directly associated with all new wells and existing active wells (conventional wells and coalbed natural gas wells). There is approximately 43,575 acres of new short-term surface disturbance (41,906 acres for conventional wells plus 1,669 acres for coalbed natural gas wells) projected. About 35,464 acres of disturbance (34,354 acres plus 1,110 acres) are projected on Bureau managed oil and gas minerals. This projected disturbance will only occur if all 6,333 new projected wells are drilled. Total short-term surface disturbance (for new wells plus existing wells) would be 49,676 acres, with 39,593 of those acres on Bureau managed oil and gas minerals.

Projections of long-term activity and disturbance are also shown on Table 20. The projection is that about 4,762 (4,572 conventional wells plus 190 coalbed natural gas wells) of the 6,333 newly drilled conventional oil and gas wells will remain in an active status, with about 3,874 of those wells (3,748 conventional wells plus 126 coalbed natural gas wells) located on Bureau managed oil and gas minerals. About 1,571 wells (6,333 total wells minus 4,762 wells remaining active) will be drilled and immediately abandoned or become productive for a short time, but be abandoned and reclaimed by the end of the Analysis Period. Of those 1,571 abandoned wells, 1,281 wells will be located on Bureau managed oil and gas minerals (5,155 total Bureau managed wells minus 3,874 wells remaining active).

Finally, Table 20 shows the calculated unreclaimed acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 12,571 acres of unreclaimed surface disturbance (12,069 acres of conventional disturbance plus 502 acres of coalbed natural gas disturbance) from new wells drilled during the Analysis Period could remain in the long-term. About 10,228 acres of unreclaimed disturbance (9,894 acres conventional plus 334 acres coalbed natural gas) could occur on Bureau managed oil and gas minerals in the long-term. Total unreclaimed long-term surface disturbance (for new producing wells plus existing wells) would be 17,649 acres, with 13,674 of those acres on Bureau managed oil and gas minerals.

Surface disturbance was also calculated in the same manner for Alternative A (Table 21), Alternative B (Table 22), and Alternative C (Table 23). The same assumptions were used for each alternative and only the calculated well count from Table 16 was changed.

SUMMARY

For the base line projection of oil and gas resource analyzed within the Planning Area for the Analysis Period this report 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 Analysis Period 2012 through 2031. This report projects that as many as 6,095 conventional oil and gas wells and 238 coalbed natural gas wells could be drilled during this period. The forecast of annual and cumulative conventional oil and gas production and coalbed natural gas production for 2012 through 2031 for the newly drilled conventional oil and gas wells is presented in Table 13. Short-term and long-term surface disturbance associated with existing and future conventional oil and gas wells and coalbed natural gas wells is presented in Table 20 for all lands and for Bureau managed lands. For this analysis of the base line projection, this report assumed that the only land use restrictions on future oil and gas resource development would be those that have been legislatively imposed (Wilderness Study Area withdrawals).

Additional analysis of potential restrictions on future oil and gas activities related to Alternatives A, B, and C resulted in recalculations of the well count for each alternative (Table 16). The oil and gas and coalbed natural gas production was recalculated for each alternative (Tables 17, 18 and 19) as were short-term and long-term disturbance (Tables 21, 22, and 23).

I would like to thank Ms. Cathy Stilwell (geographical information specialist), Ms. Amber Robbins (geologist), Mr. Stan Davis-Lawrence (petroleum engineer), and Mr. Joe Rochelle (petroleum engineer) of the Bureau of Land Management Wyoming State Office Reservoir Management Group staff and Alfred Elser (Ph.D.) of the Bureau of Land Management, High Plains District for the important contributions that they have made to this reasonable foreseeable development analysis. In addition I would like to thank Trisha Cartmell of the Rock Springs Field Office for her assistance in formulating projections of future activity.

REFERENCES

Andrews, S.G., 1965, The Rock Springs Uplift, a history of mineral exploration and exploitation: in Wyoming Geological Association Nineteenth Field Conference Guidebook, Sedimentation of late Cretaceous and Tertiary outcrops, Rock Springs Uplift, p. 231-233.

Armstrong, F.C., and Oriel, S.S., 1965, Tectonic development of Idaho-Wyoming thrust belt: American Association of Petroleum Geologists Bulletin, v. 49, no. 11, p. 1847-1866.

Avery, C.D., and J.C. Miller, 1934, Relationship of geology to unit operation of oil and gas fields, involving Government lands: Bulletin of the American Association of Petroleum Geologists, volume 18, number 11, pp. 1454-1492.

Becker, T.P, and R. Lynds, 2012, A geologic deconstruction of one the world's largest natural accumulations of CO2, Moxa Arch, southwestern Wyoming: American Association of Petroleum Geologists Bulletin, volume 96, number 9, p. 1643-1664.

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 pages.

Biggs, P, and R.H. Espach, 1960 Petroleum and natural gas fields in Wyoming: U.S. Bureau of Mines Bulletin 582, 538 pages

Blackstone, D.L., Jr., 1990, Precambrian basement map of Wyoming: Geologic Survey of Wyoming, Map Series 27, one map.

Blackstone, D.L., Jr., 1993, The Wind River Range, Wyoming: An Overview: in Wyoming Geological Association Jubilee Anniversary Field Conference Guidebook, p. 121-140.

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

Burton, G., 1961, Patrick Draw area Sweetwater Co., Wyoming: in Wyoming Geological Association 16th Annual Field Conference Guidebook, Symposium on Late Cretaceous Rocks, Wyoming and Adjacent Areas, p. 276-279.

Carbon Management Institute, 2012, Wyoming carbon underground storage project. Available online: http://www.uwyo.edu/cmi/research-projects/ .

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. Available online: http://pubs.usgs.gov/fs/fs-202-96/FS-202-96.html .

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.

Cook, B.R., 2112, The economic contribution of CO_2 enhanced oil recovery in Wyoming's economy: University of Wyoming Department of Economics & Finance Enhanced Oil Recovery Institute, June 2012, 43 pages. Available at: http://www.uwyo.edu/cee/_files/docs/cook-benjamin-economic-contribution-co2-eor.pdf .

Cook, L., R.H. De Bruin, C.S. Boyd, and R.W. Jones, 2002, Oil and gas resource assessment of the Jack Morrow Hills and surrounding areas, southwestern Wyoming: Wyoming State Geological Survey, Open File Report 2002-1. Available online: http://www.wsgs.uwyo.edu/News/Mar27_2002B.aspx

Cox, J.E., 1962, Patrick Draw Field & adjacent areas Sweetwater County, Wyoming: Billing Geological Society Papers #1, 18 pages.

DeBruin, R.H., 2012, Oil and gas field map of Wyoming: Wyoming State Geologic Survey MS-55, cd-rom disc.

Dickinson, R.G., 2001, Searching for overpressured Frontier Formation gas in the Washakie Basin, Wyoming: in Gas in the Rockies, Rocky Mountain Association of Geologists, p. 117-123.

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.

EnCana, 2008, Vapor recovery: *from* Lessons learned from natural gas STAR partners, 16 pages. Downloaded from http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings6.pdf .

Energy Information Administration, 2001, U.S. natural gas markets: mid-term prospects for natural gas supply: Report # SR-OIAF/2001-06, five pages. Downloaded from http://www.eia.gov/oiaf/servicerpt/natgas/chapter2.html .

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, Performance profiles of major energy producers 2006: U.S. Department of Energy, Office of Energy Markets and End Use, published December, 2007; DOE/EIA-0206(06), 102 pages. Available online: http://www.eia.gov/FTPROOT/financial/020606.pdf .

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. Available online: http://www.eia.doe.gov/oiaf/aeo/assumption/index.html .

Energy Information Administration, 2010, Oil and Gas Lease Equipment and Operating Costs 1994 Through 2009: 8 pages and excel spreadsheet. Available online: http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html and excel spreadsheet available online: http://www.eia.doe/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.xlsh .

Energy Information Administration 2011a, Performance profiles of major energy producers 2009: U.S. Department of Energy, Office of Energy Markets and End Use, published February, 2011; DOE/EIA-0206(09), 70 pages. Available online: http://www.eia.gov/finance/performanceprofiles/pdf/020609.pdf .

Energy Information Administration, 2011b, Review of emerging resources: U.S. shale gas and shale oil plays. 105 pages. Available online: ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf .

Energy Information Administration, 2012, Annual Energy Outlook 2012 Early Release Overview. Retrieved January 23, 2012, from the Energy Information Administration website: http://www.eia.gov/forecasts/aeo/er/early_prices.cfm .

Energy Information Administration, 2012b, Petroleum and other liquids data. Available online: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpwy1&f=a .

Energy Information Administration, 2012c, Natural gas data. Available online: http://www.eia.gov/dnav/ng/hist/n9050wy2a.htm .

Espach, R.H., and H.D. Nichols, 1941, Petroleum and natural-gas fields in Wyoming" United States Department of the Interior Bureau of Mines, Bulletin 418, 185 pages.

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

Fidlar, M.M., 1950, Baxter Basin gas fields Sweetwater County, Wyoming: in Wyoming Geological Association Fifth Annual Field Conference – Southwestern Wyoming, p. 109-110.

Fidlar, M.M., 1962, Baxter Basin gas fields, Sweetwater County, Wyoming: in Wyoming Geological Association Seventeen Annul Field Conference Guidebook – Symposium on Early Cretaceous Rocks of Wyoming and Adjacent Areas, p. 282-283.

Finn, T. M. and E.A. Johnson, 2002, (2002). Assessment of undiscovered oil and gas resources of the southwestern Wyoming province, chapter 6: U.S. Department of the Interior, U.S. Geological Survey Digital Data Series (DDS-69-D). Retrieved from website: http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/USBasinSummaries.aspx?provcode=5037.

Fontenot, K.R., B. Lesso, R.D. Strickler, and T.M. Warren, 2005, Using casing to drill directional wells: in Oilfield Review, summer 2005, p. 44-61. Online at: http://www.slb.com/~/media/Files/resources/oilfield_review/ors05/sum05/04_casing_drilling.ashx .

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 pages.

Gaines, J., 2008, Monell Unit CO_2 Flood Patrick Draw Field Sweetwater County, Wyoming: University of Wyoming Department of Economics & Finance Enhanced Oil Recovery Institute, May 29th, 2008, 33 pages. Downloaded from: http://www.uwyo.edu/eori/_files/co2conference08/jason%20gaines_anadarko_eori_co2%20casper%20may%2029%202008.pdf

Gobec, M., T. Van Leeuwen, and V. Kuuskraa, 2007, Economics of unconventional gas: OGJ Unconventional Gas Article #5, 14 pages. Available online: http://www.adv-res.com/Literature.asp.

Gras, V.B., 1955, Vermilion Creek Basin area, Sweetwater County, Wyoming, and Moffat County, Colorado: in Wyoming Geological Association Guidebook Tenth Annual Field Conference, p. 177-181.

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

Hayes, T., 2004, The electrodialysis alternative for produced water management: Gas Tips, Volume 10, Number 3, pages 15-20. Available online: http://www.netl.doe.gov/technologies/oil-gas/publications/GasTIPS/GasTIPS-Summer04.pdf .

Hunt, G.L., 2012, Low gas prices rattle renewables: http://www.tclabz.com/2012/01/22/low-gas-prices-rattle-renewables/.

IHS Energy Group, 2012, Rocky Mountain US Well Data: Network License for PI/Dwights PLUS Version 1.7.

International Programme on Chemical Safety, 1994, Assessing human health risks of chemicals: derivation of guidance values for health-based exposure limits: Geneva, World Health Organization (Environmental Health Criteria 170). Available online: http://www.inchem.org/documents/cicads/cicads/cicad53.htm .

Interstate Oil and Gas Compact Commission, 2009, Marginal Wells: fuel for economic growth. Interstate Oil & Gas Compact Commission 2008 Edition, 58 pages. Available online: http://www.iogcc.state.ok.us.

Interstate Oil and Gas Compact Commission, 2010, Marginal Wells: fuel for economic growth. Interstate Oil & Gas Compact Commission 2009 Edition, 21 pages. Available online: http://www.iogcc.state.ok.us .

Isaacs, A., B. Mordick, and A. Williams, 2009, Enhance oil recovery by CO2 injection, Powder River and Washakie basins, Wyoming: Abstract, American Association of Petroleum Geologists Annual Convention: June 7-10, 2009.

Kaiser, Mark J., 2012, Louisiana Haynesville Shale. *Oil & Gas Journal*. Vol. 110. Retrieved January 23, 2012 from http://www.ogj.com/articles/print/vol-110/issue-1a/exploration-development/louisiana-haynesville-p1.html .

Kirschbaum, M., T.M. Finn, R.D. Hettinger, and E.A. Johnson, 2002, Assessment of undiscovered oil and gas resources of the southwestern Wyoming province: U.S. Department of the Interior, U.S. Geological Survey Digital Data Series (DDS-69-D). Retrieved from website: http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/USBasinSummaries.aspx?provcode=5037.

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. Available online: 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. Available online: 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. Available online: http://www.rand.org.pubs/.

Law, B. E., 1995, Southwestern Wyoming Province (037), in Gautier, D. L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., ed., 1995 National Assessment of the United States of oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30, Release 2, one CD-ROM. http://certmapper.cr.usgs.gov/data/noga95/prov37/text/prov37.pdf .

Lawson, D.E., and C.W. Crowson, 1961, Geology of the Arch Unit and adjacent areas Sweetwater County, Wyoming: in Wyoming Geological Association 16th Annual Field Conference Guidebook, Symposium on Late Cretaceous Rocks, Wyoming and Adjacent Areas, p. 280-289.

Levorsen, A.I., 1967, Geology of Petroleum: Second edition, W.H. Freeman Company, San Francisco. 724 pages.

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 pages.

May, B.E., 1961, The Desert Springs Field: in Wyoming Geological Association 16th Annual Field Conference Guidebook, Symposium on Late Cretaceous Rocks, Wyoming and Adjacent Areas, p 290-293.

Mazerov, K., 2010, Coiled tubing pushing its limits by going bigger, expanding niche applications, thinking riserless: online in Drilling Contractor: http://www.drillingcontractor.org/coiled-tubing-pushing-its-limits-by-going-bigger-expanding-niche-applications-thinking-riserless-4655 .

McCubbin, D.G., and M.J. Brady, 1969, Depositional environment of the Almond reservoirs, Patrick Draw Field, Wyoming; Rocky Mountain Association of Geologists, The Mountain Geologist, volume 6, p. 3-26.

Mees, E.C., J.D. Copen, and J.C. McGee, 1961, Table Rock Field, Sweetwater County, Wyoming: in Symposium on late Cretaceous rocks of Wyoming, Wyoming Geological Association Sixteenth Annual Field Conference Guidebook, p. 294-300.

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. Available online: http://www.npc.org.

National Petroleum Council, 2012, Prudent Development: Realizing the Potential of North America's Natural Gas and Oil Resources. Retrieved January 23, 2012 from http://www.ogj.com/articles/print/vol-110/issue-1a/exploration-development/louisiana-haynesville-p1.html .

Nightingale, W.T., 1930, Geology of Vermilion Creek gas area in southwest Wyoming and northwest Colorado: American Association of Petroleum Geologists Bulletin 14, Issue Number 8, p. 1013-1040.

Nightingale, W.T., 1935, Geology of Baxter Basin gas fields, Sweetwater County, Wyoming: in AAPG Special Volume Number 7, Geology of natural gas, p. 323-339.

Norris, G.E., and D.H. Phillips, 2002, Rediscovering Bitter Creek Field as a basin centered gas play in the Washakie basin area of the Greater Green River Basin, Wyoming, U.S.A.: American Association of Petroleum Geologist Search and Discovery Article #90007, meeting abstract.

Nummedal, D., B. Towler, C. Mason, and M. Allen, 2003, Enhanced Oil Recovery in Wyoming: University of Wyoming, 26 pages. Available online: http://www.uwyo.edu/acadaffairs/_files/docs/eorfinal.pdf .

Olson, R.B., 1955, Middle Mountain Field, Sweetwater County, Wyoming: in Green River Basin, Wyoming Geological Association Tenth Annual Field Conference Guidebook, p. 148-149.

Parker, J.M., and R.R. Ray, 2001, A chronology of seismic exploration in the Rockies: An update to guide us into the year 2001 and beyond: The Mountain Geologist, Volume 38, Number 1 (January 2001), p. 43-51.

Peterson, J.A., 1977, Paleozoic shelf-margins and marginal basins, western Rocky Mountains - Great Basin, United States, in Rocky Mountain thrust belt geology and resources: Wyoming Geological Association 29th Annual Field Conference, p. 135-153.

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.

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

Radler, Marilyn, 2012, US energy demand to stay weak in 2012 amid strong oil, gas production. Retrieved January 23, 2012 from http://www.ogj.com/articles/print/vol-110/issue-1a/exploration-development/louisiana-haynesville-p1.html .

Raymond James & Associates Inc., 2012, Market Watch: Gas prices continue falling compared with small decline for oil. *Oil & Gas Journal*. Retrieved January 23, 2012 from http://www.ogj.com/articles/2012/01/market-watch-gas-prices-rises.article.html .

Reese, D., 1968, Gas fields of Rock Springs Uplift, Sweetwater County, Wyoming: in American Association of Petroleum Geologists Memoir No. 9, Natural gases of North America, volume 1, p. 803-816.

Reeves., S.R., G.J. Koperna, and V.A. Kuuskraa, 2007, Nature and importance of technology progress for unconventional gas: OGJ Unconventional Gas Article #4, 14 pages. Available online: http://www.adv-res.com/Literature.asp.

Ritzma, H.R., 1963, Geology and occurrence of oil and gas, Wamsutter Arch, Wyoming: in American Association of Petroleum Geologists Memoir No. 2, Backbone of the Americas, p. 188-195.

Roberts, L.N.R., M.D. Lewan, and T.M. Finn, 2005, Burial history, thermal maturity, and oil and gas generation history of petroleum systems in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah: Chapter 3 in Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah, 25 pages, U.S. Geological Survey Digital Data Series DDS-69-D.

Rock Well Petroleum, 2009, Company website operations information. Available online: http://www.rockwellpetroleum.com/operations/target.php.

Rocky Mountain Federal Leadership Forum, 2004, 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 Report published January 16, 2004; 100 pages.

Rocky Mountain Oil Journal, 2012, Weekly News Periodical, volume 92, number 39, 24 pages.

Ryder, R.T., M.W. Lee, and G.N. Smith, 1981, Desert Springs Field, Sweetwater County, Wyoming: in American Association of Petroleum Geologists Methods in Exploration Series #2; Seismic Models of Sandstone Stratigraphic Traps in Rocky Mountain Basins, p 16-19.

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.

Schaefer, K., 2010, The 3-break even prices for natural gas. *Oil and Gas Investment Bulletin*, April 12, 2010 issue (online). Retrieved March 18, 2011 from http://oilandgas-investments.com/2010/natural-gas/the-3-break-even-prices-for-natural-gas/ .

Skrtic, L., 2006. Hydrogen Sulfide, Oil and Gas, and People's Health: Master of Science thesis, Energy and Resources Group, University of California, Berkley, 77 pages.

Spears & Associates, Inc., 2003, U.S. Department of Energy microhole initiative workshop summary. Available online: http://fossil.energy.gov/programs/oilgas/microhole/microhole-workshop-report.pdf.

Steidtmann, J.R., Middleton, L.T., and Shuster, M.W., 1989, Post-Laramide (Oligocene) uplift in the Wind River range, Wyoming: Geology, v. 17, p. 38-41.

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. Available online: http://www.netl.doe.gov/technologies/oil-gas/publications/AP/Coiled%20Tubing%20Topical%20Report%20June%202005.pdf.

U.S. Department of Energy, 2007, Carbon sequestration atlas of the United States and Canada. Available online: http://www.netl.doe.gov/technologies/cabron_seq/refshelf/atlas/index.html .

U.S. Department of Energy, 2008a, Enhanced oil recovery/CO2 Injection. Available online: http://www.fossil.Energy.gov/programs/oilgas/eor/.

U.S. Department of Energy, 2010, 2010 Carbon sequestration atlas of the United States and Canada, third edition: 162 pages. Available online: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/ .

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. Available online: 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. Available online: 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. Available online: http://www.doi.gov/ or http://www.blm.gov/.

U.S. Geological Survey, 2002, Assessment of undiscovered oil and gas resources of the Southwestern Wyoming Province, 2002: U.S. Geological Survey Fact Sheet FS-145-02 or available online: http://energy.cr.usgs.gov/oilgas/noga/ .

U.S. Geological Survey, 2005, Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series 69-D or available online: http://energy.cr.usgs.gov/oilgas/noga/ .

U.S. Geological Survey, 2008, Produced waters database. Available online: http://energy.cr.usgs.gov/prov/prodwat/intro.htm.

U.S. Geological Survey National Assessment, 2011, National Assessment of oil and gas resources update: Conventional oil and gas resources. (2011, August). Retrieved from http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/2011/2011final_table_conventional.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. Available online: http://www.rand.org.pubs/

Webb, D., 2011, 'Big-City' ozone goes rural: Grand Junction Sentinel of March 23, 2011. Downloaded from http://www.gjsentinel.com/news/articles/bigcity_ozone_goes_rural .

Weimer, R.J, 1965, Stratigraphy and petroleum occurrences, Almond and Lewis formations (Upper Cretaceous), Wamsutter Arch, Wyoming: in Wyoming Geological Association 19th Annual Field Conference Guidebook, Sedimentation of Late Cretaceous and Tertiary Outcrops, Rock Springs Uplift, p 65-80.

Weimer, R.J., 1966, Time-stratigraphic analysis and petroleum accumulations, Patrick Draw Field, Sweetwater County, Wyoming: in American Association of Petroleum Geologist Bulletin, volume 50, number 10, p. 2150-2175.

Welder, G.E., 1968, Ground-water reconnaissance of the Green river Basin southwestern Wyoming: U.S. Geological Survey, Hydrologic Investigations Atlas HA-290, two sheets.

White, V.L., 1955, Table Rock and Southwest Table Rock gas fields: in Green River Basin, Wyoming Geological Association Tenth Annual Field Conference Guidebook, p. 170-171.

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.

Wyoming Geological Association, 1950, Southwest Wyoming: Wyoming Geological Association fifth annual field conference, 196 pages.

Wyoming Geological Association, 1955, Green River Basin: Tenth annual field conference, 255 pages

Wyoming Geological Association, 1957 and 1961, Wyoming oil and gas fields symposium: Wyoming Geological Association 1957 Symposium Committee, with supplement of 1961, 579 pages.

Wyoming Geological Association, 1961, Symposium on late Cretaceous rocks of Wyoming: Sixteenth Annual Field Conference, 351 pages

Wyoming Geological Association, 1962, Symposium on early Cretaceous Rocks of Wyoming: Seventeenth Annual Field Conference, 339 pages

Wyoming Geological Association, 1965, Sedimentation of late Cretaceous and Tertiary outcrops, Rock Springs Uplift: Nineteenth Field Conference, 233 pages.

Wyoming Geological Association, 1972, Rocky Mountain fields oil & gas symposium: Wyoming Geological Association, 142 pages

Wyoming Geological Association, 1979 and 1992, Wyoming oil and gas fields symposium greater Green River basin and Overthrust belt: Oil and Gas Symposium Committee, two volumes.

Wyoming Oil and Gas Conservation Commission, 2012, Wyoming well data and statistics: Wyoming Oil and Gas Conservation Commission Online database. Available online: http://wogcc.state.wy.us.

Wyoming State Geological Survey, 2012, Downloadable GIS data: Available online: http://www.wsgs.uwyo.edu/GIS_and_online_maps/digital_data.aspx.

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.

Adsorbed (adsorption). The adherence of gas molecules to the surface of solids (coal or shale particles) with which they are in contact.

Anticline. A fold, generally convex upwared, whose core contains the oldest rocks.

Arch. A broad, open anticlinal fold on a regional scale.

Associated water. Water that is produced from a well that also produces coalbed natural gas.

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 (see Glossary), or as continuous, if it contains continuous accumulations (see Glossary).

Basin. A low area in the earth's crust, of tectonic origin, in which sediments have accumulated. Such features were drainage basins at the time of sedimentation but are not necessarily so today.

BTU. Brittish Thermal Unit. A measure of heat energy. One million BTU's is the heating value of one thousand cubic feet of methane.

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.

Coalbed natural gas. The gas that is produced from coalbeds. It is mostly biogenic and may include nitrogen and carbon dioxide. Coalbed natural gas is used inerchangeably with coalbed gas.

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

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

Deeper pool wildcat. On already producing structure and pool, but on a deeper pay zone.

Development well. Can be on the extension of a pay zone, or between existing wells (infill).

Diagenetic pore-throat trap. A stratigraphic 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.

Eocene. An epoch of the early Tertiary period, after the Paleocene and before the Oligocene; also, the corresponding world-wide series of rocks.

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.

Infill drilling. Additional wells drilled between existing wells in an effort to increase the recovery of oil or gas from a reservoir.

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

Lacustrine. Pertaining to, produced by, or formed in a lake or lakes.

Laramide orogeny. A time of deformation in the Rocky Mountains extending from late Cretaceous time until the end of the Paleocene.

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

Natural gas liquids. 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.

New field wildcat. Far from other producing fields and on a structure that has not previously produced.

New pool wildcat. New pool on already producing structure.

Nonconventional gas (Unconventional gas). Nonconventional gas is generally thought of as gas that is created in formations without the permeability necessary to allow significant migration. It is generally described as those gas accumulations that are hard to discover, characterize, and commercially produce by common exploration and production technologies. It may include coalbed natural gas, tight sand, tight carbonates, shale, or deep gas.

Normal fault. A fault in which the hanging wall appears to have moved downward relative to the footwall. The angle of the fault is usually greater than 45°.

Outpost wildcat. Usually two or more locations from the nearest productive area.

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.

Play area. An area where productive oil or gas wells may be drilled based on a specific geologic concept

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

Public domain. Minerals that have been owned continuously by the United States.

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

Shallow pool wildcat. On already producing structure and pool, but on a deeper pay zone.

Spacing pattern. The pattern of well locations, usually one well location per 80 acres for coals in the Buffalo Planning Area. More than one coalbed natural gas well may be drilled on a location.

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

Stratigraphic test. A well drilled to obtain geologic and/or engineering data about the coal.

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.

Syncline. A fold of which the core contains the stratigraphically younger rocks. It is generally concave upward.

Technically recoverable resources. The volume of hydrocarbons which are recoverable using current exploration and production technology without regard to cost, which is a proportion of the estimated in-place resource.

Thrust fault. A fault with a dip of 45° or less over much of its extent, on which the hanging wall appears to have moved upward relative to the footwall. Horizontal compression rather than vertical displacement is its characteristic feature.

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 is therefore closely associated with the generation and migration of petroleum. The geologic elements of a total petroleum system, include (1) source-rock distribution, thickness, organic richness, maturation, petroleum generation, and migration; (2) reservoir-rock type (conventional or continuous), distribution, and quality; and (3) character of traps and time of formation with respect to petroleum generation and migration.

Undiscovered technically recoverable resource. A subset of the in-place resource hypothesized to exist on the basis of geologic knowledge, data on past discoveries, or theory, and that is contained in undiscovered accumulations outside of known fields. Estimated resource quantities are producible using current recovery technology but without reference to economic viability. These resources are therefore dynamic, constantly changing to reflect our increased understanding of both the in-place resource

as well as the likely nature of future technology. Only accumulations greater than or equal to 1 million barrels of oil or 6 billion cubic feet of gas were included in the earlier 1995 assessment.

Unstable grains. Said of mineral grains within a sedimentary rock, that don't resist chemical change after deposition.

Uplift. A structurally high area in the crust, produced by positive movements that raise or upthrust the rocks, as in a dome or arch.

Wildcat wells. Those drilled outside of and not in the vicinity of known oil or gas fields.

Figure 1.
The Rock Springs Field Office and its location within Wyoming.

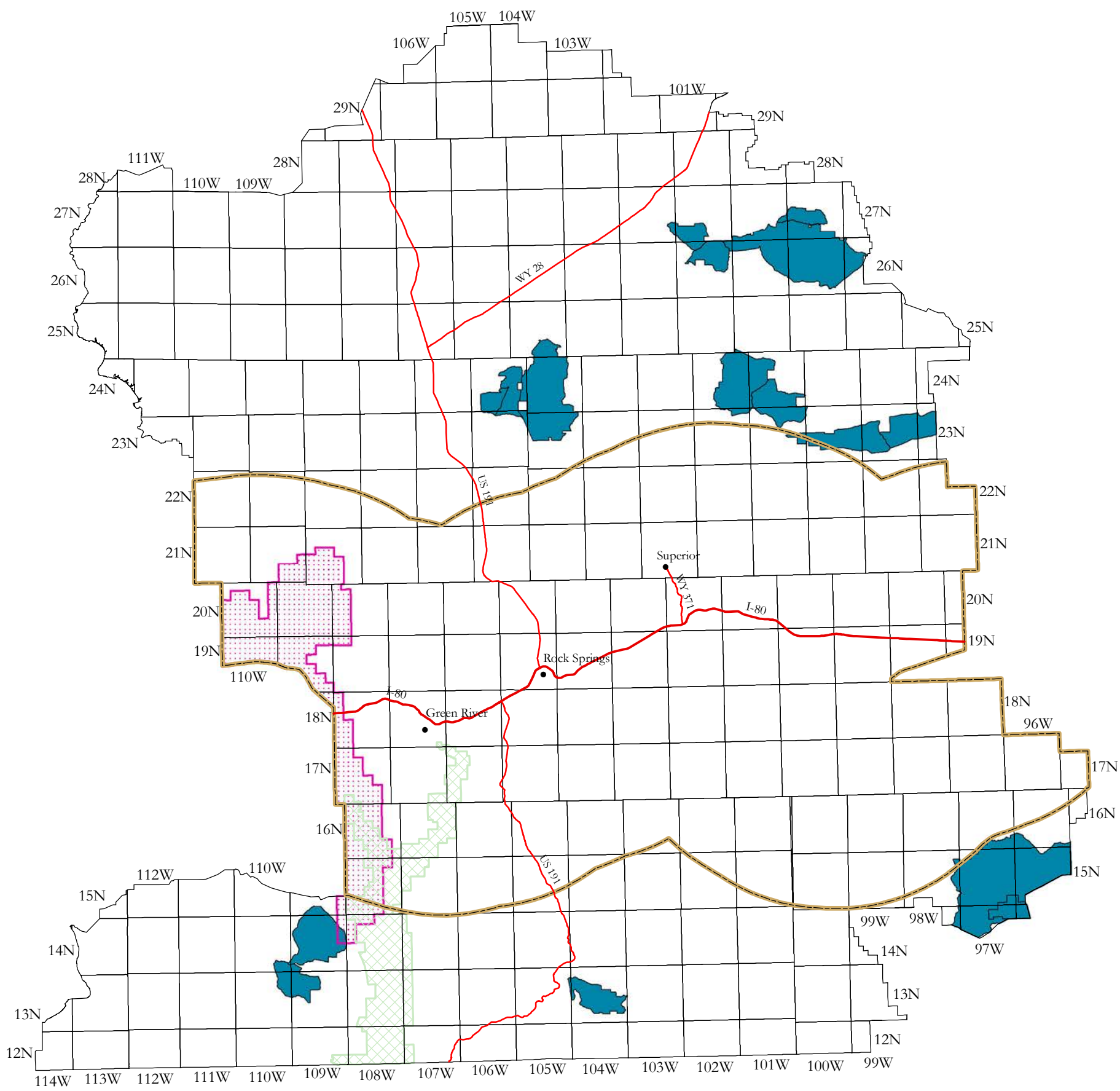
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data.
Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 2.

Base map of Rock Springs Planning Area.



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

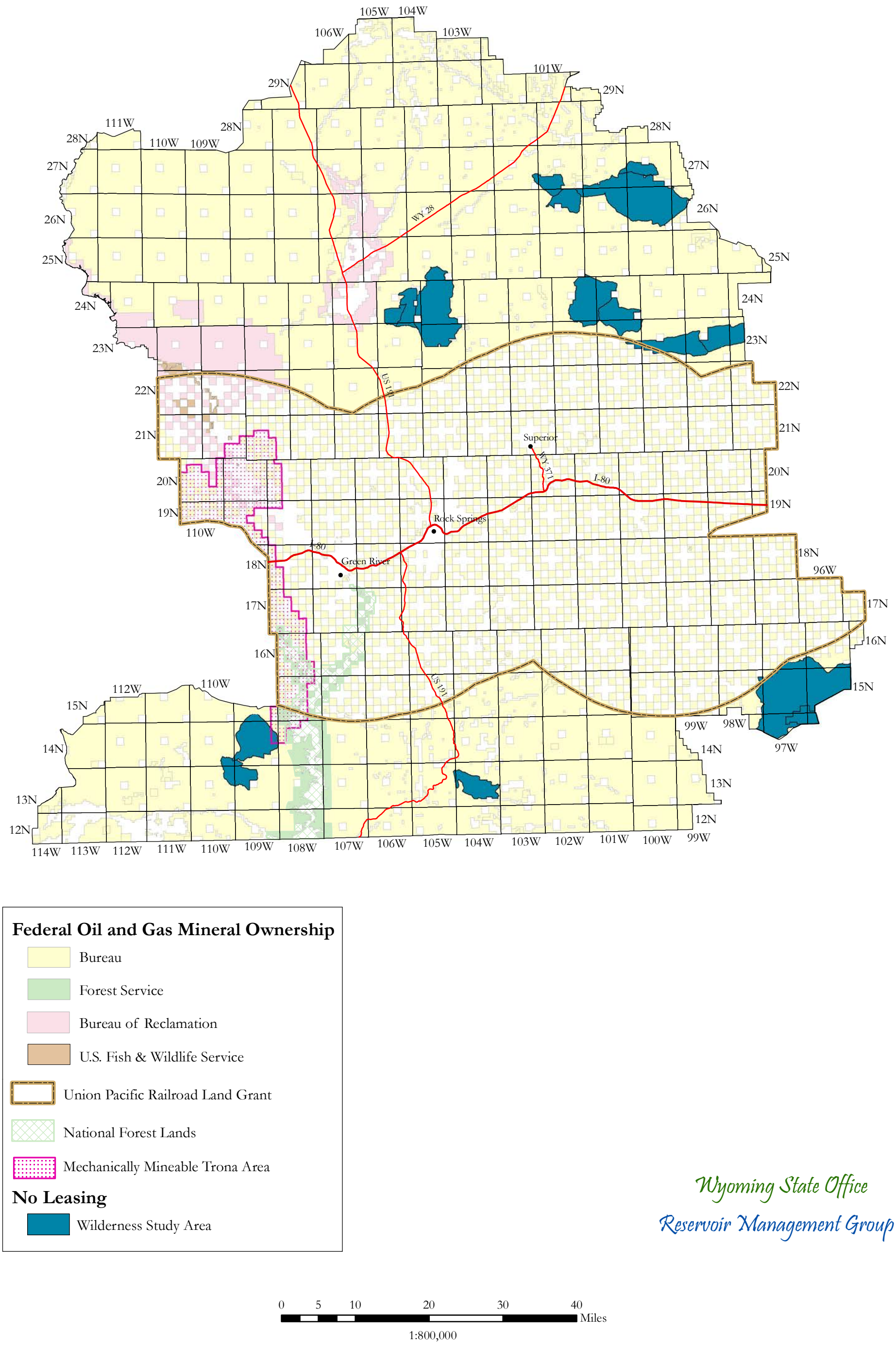
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 3.

Location of Federal oil and gas mineral ownership within the Rock Springs Planning Area.



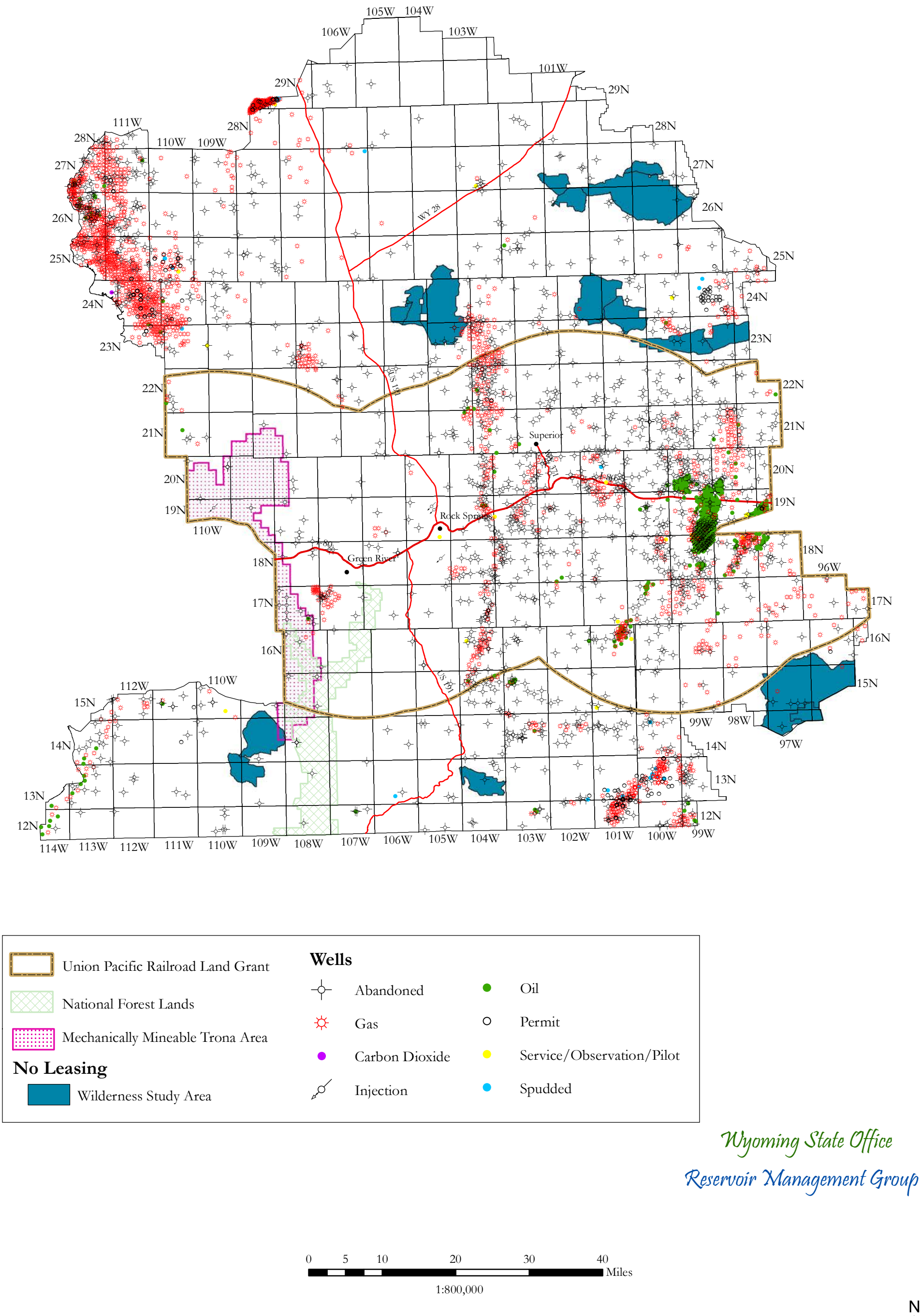
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 4a.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

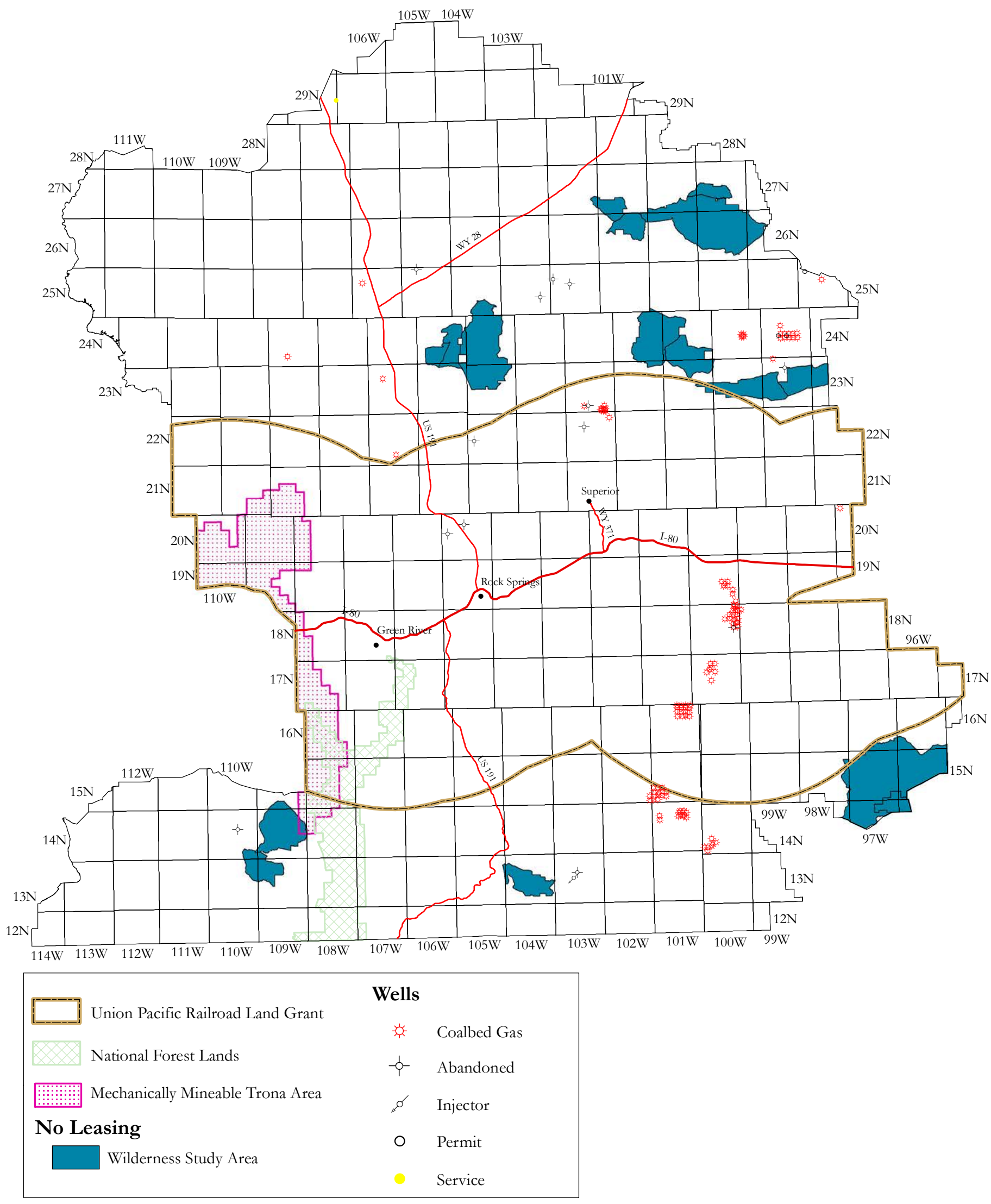
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 4b.

Location and initial status of all coalbed natural gas wells drilled within the Rock Springs Planning Area. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

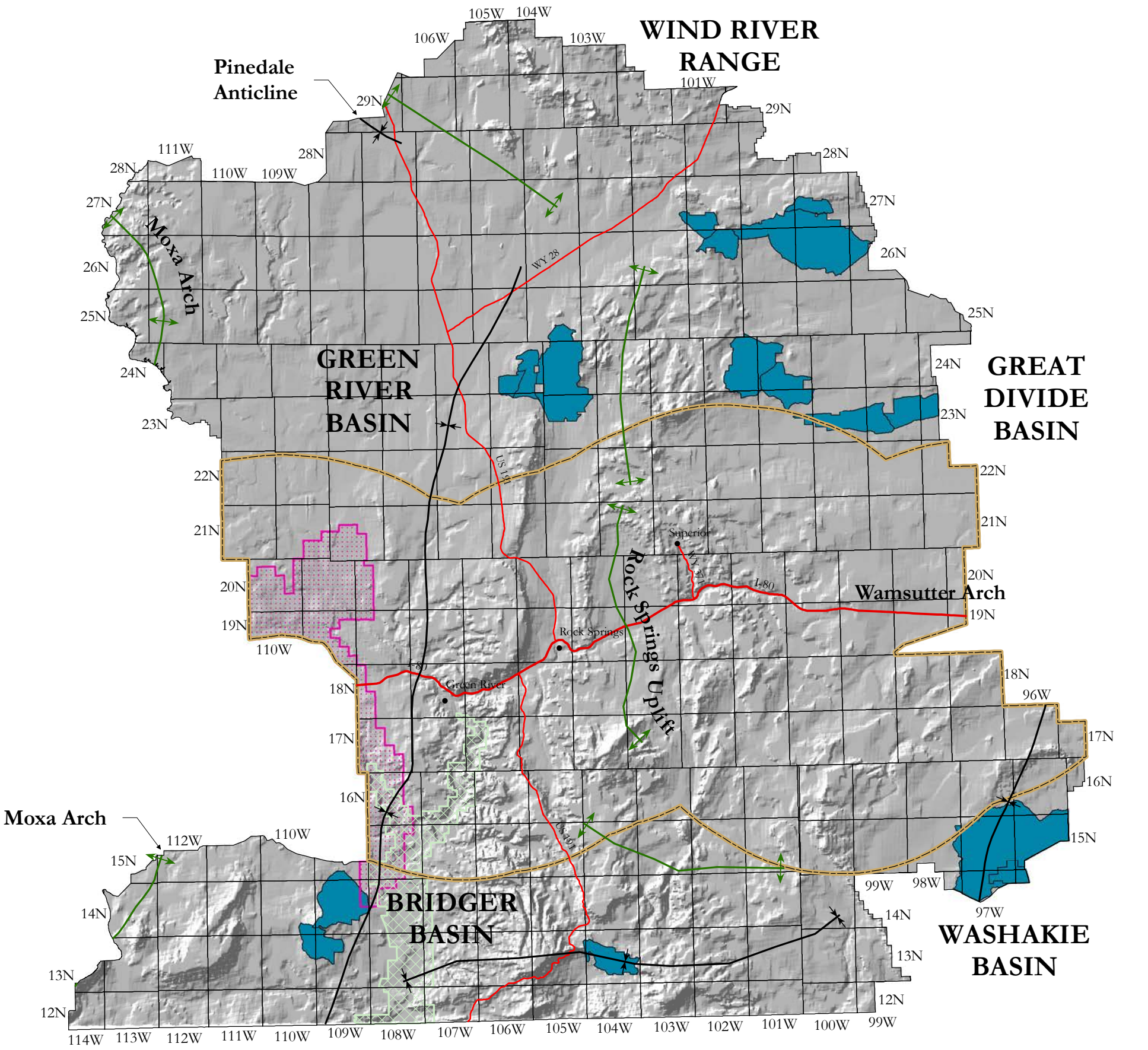
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 5a.

Major structural elements of the Rock Springs Planning Area. Data from DeBruin (2007).

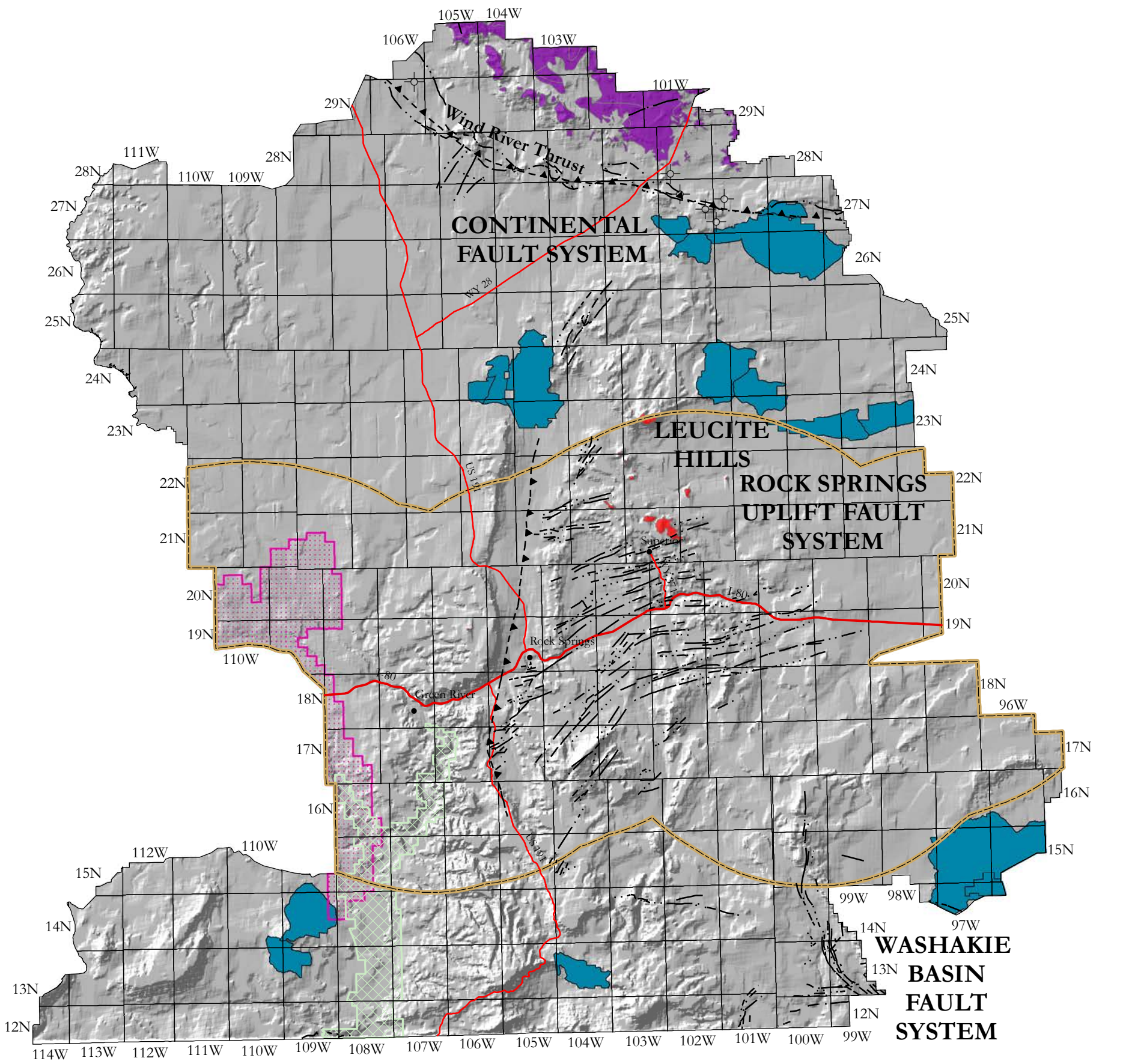


June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 5b.
Major thrust faults, faults and selected geologic units of the Rock Springs Planning Area. Thrust fault, fault, and geologic unit data from Wyoming State Geological Survey (2012) and Blackstone (1990).



June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

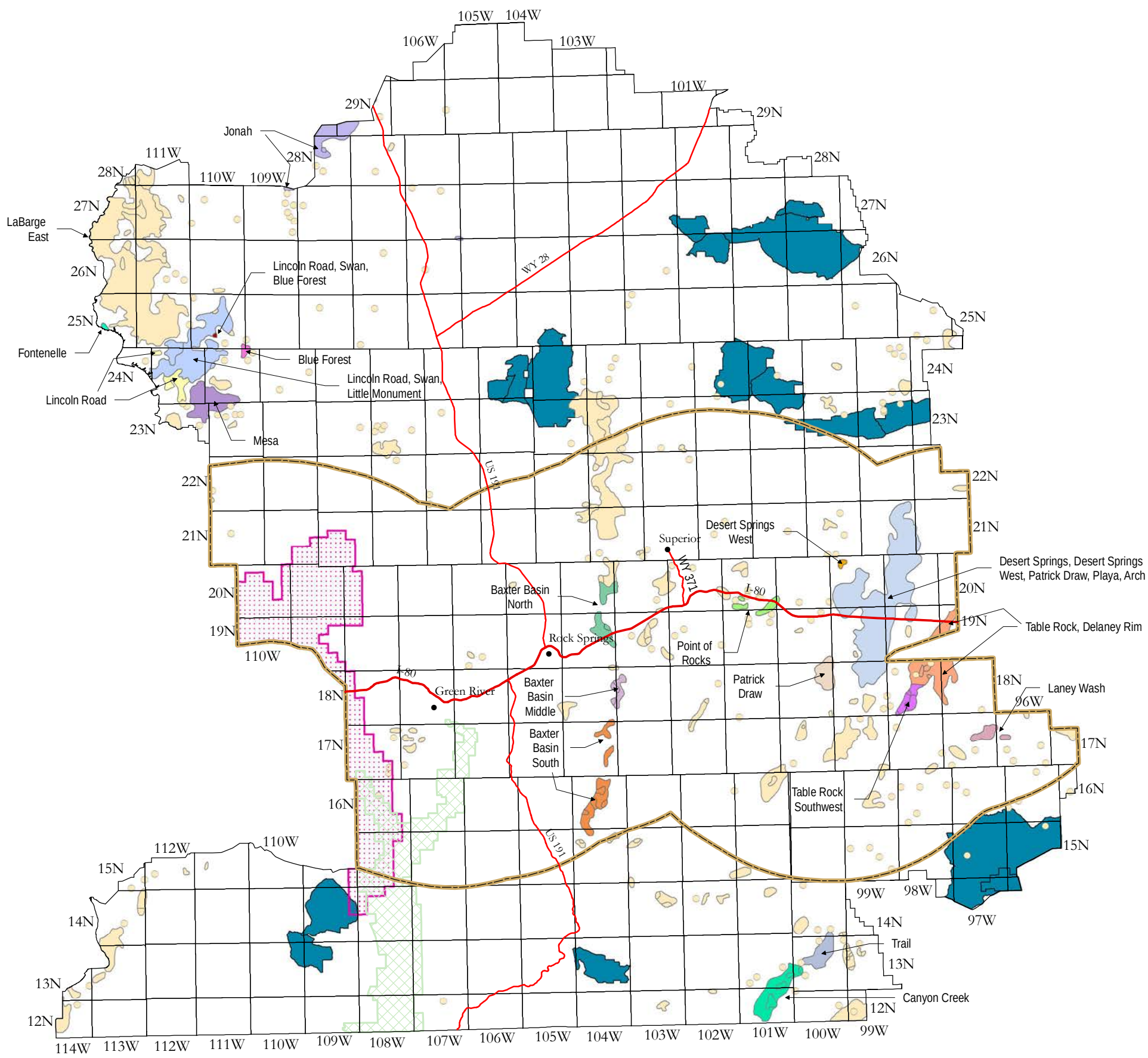
Figure 6. Generalized stratigraphic chart of the Southwestern Wyoming basin within the Planning Area (after Law, 1995; Kirschbaum et al., 2002; and Finn and Johnson, Ch. 6, 2002), with hydrocarbon and carbon dioxide producing zones.

Era	Age	Stratigraphic Unit	
Cenozoic	Tertiary		
		Bridger Formation	
		Green River Formation ●	
		Wasatch Formation ●	
		Hoback and Almy Formations	Fort Union Formation ● ●
Mesozoic	Cretaceous		
		Lance Formation ●	
		Fox Hills Sandstone ●	
		Lewis Shale ● ●	
		Mesaverde Group ● ●	Almond Formation ● ●
			Ericson Sandstone ●
			Rock Springs Formation ● ●
			Blair Formation ● ●
		Hilliard Shale	Baxter Shale ●
		Frontier Formation ● ●	
		Aspen Shale	Mowry Shale ●
		Bear River Formation ●	Muddy Sandstone ● ●
			Thermopolis Shale
			Dakota Sandstone ● ●
		Gannett Group	
	Jurassic	Stump Sandstone	Morrison Formation ● ●
		Preuss Formation	Entrada Sandstone
		Twin Creek Limestone	Carmel Formation
		Nugget Sandstone ● ●	
	Triassic	Ankareh Formation	
		Thaynes Limestone	Woodside Formation
		Dinwoody Formation	
Paleozoic	Permian	Phosphoria Formation ● ●	
	Pennsylvanian		
		Tensleep Sandstone	Weber Sandstone ● ●
		Amsden Formation	Morgan Formation ●
		Darwin Sandstone	
	Mississippian	Madison Limestone ● ● CO2	
	Devonian	Darby Formation	
	Silurian		
	Ordovician	Bighorn Dolomite	
	Cambrian		
		Gallatin Limestone	
		Gros Ventre Formation	
		Flathead Sandstone	

	Hiatus	●	Oil Producer	●	Gas Producer	CO2	CO2 Producer

Figure 7.

Oil and gas fields within the Rock Springs Planning Area. Data from DeBruin (2012).



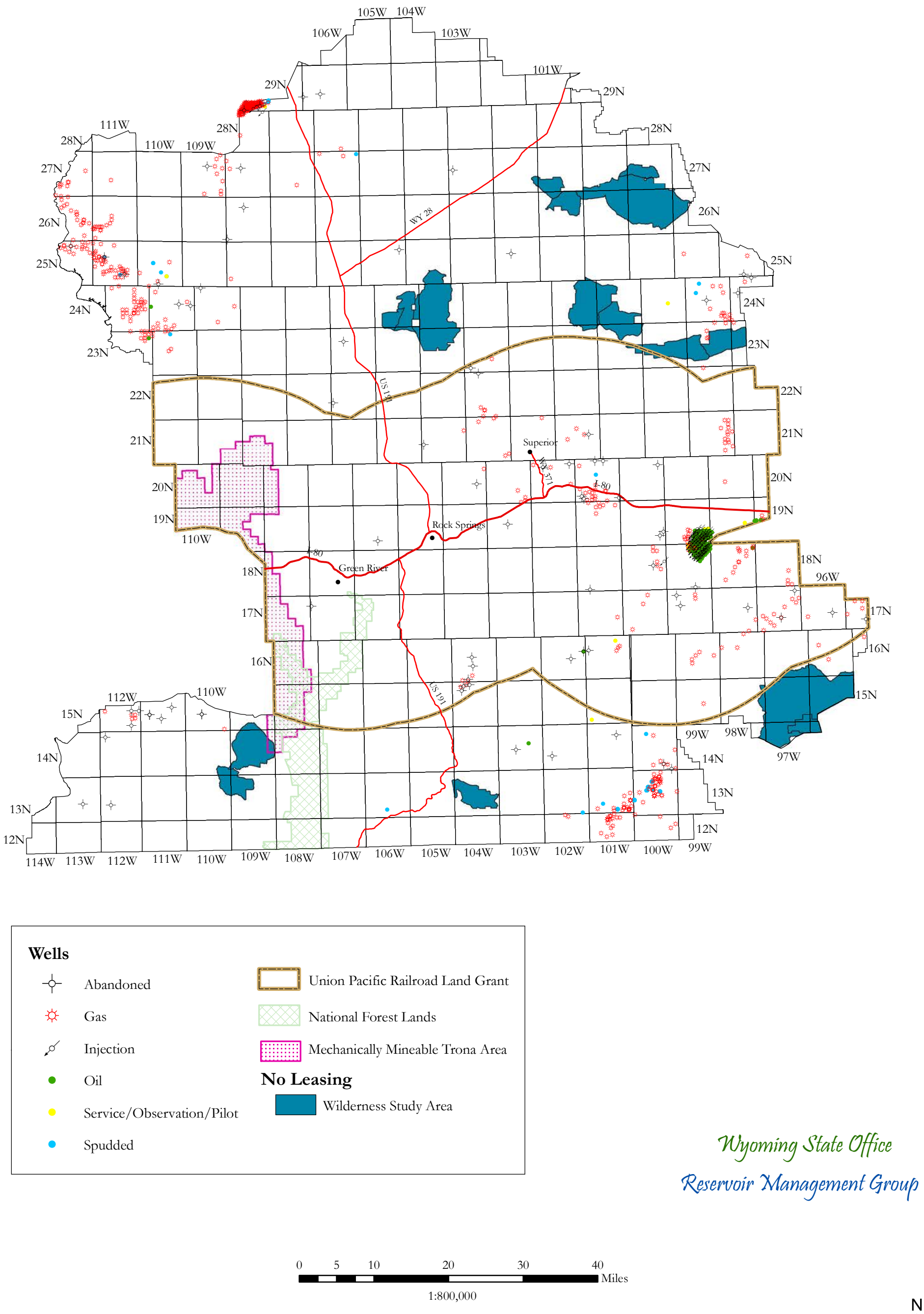
August, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 8a.

Location and initial classification of Rock Springs Planning area oil and gas wells spudded between January 1, 2002 and April of 2012. Data from IHS Energy Group (2012).

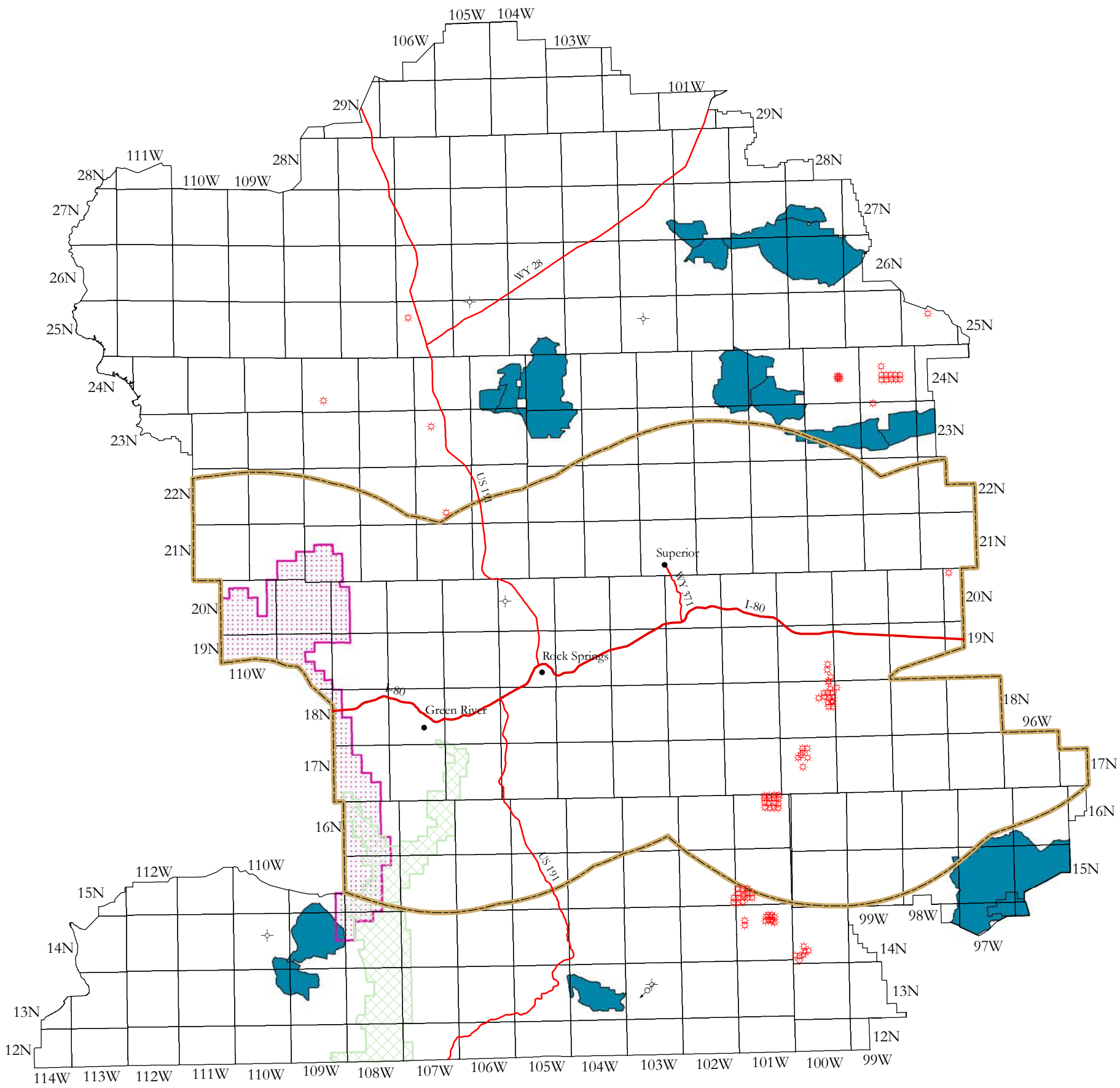


June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 8b.
Location and initial classification of Rock Springs Planning area coalbed natural gas wells spudded between January 1, 2002 and April of 2012. Data from IHS Energy Group (2012).



Wells

- Abandoned
- Coalbed Gas
- Injector
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office
Reservoir Management Group

0 5 10 20 30 40 Miles
1:800,000

N

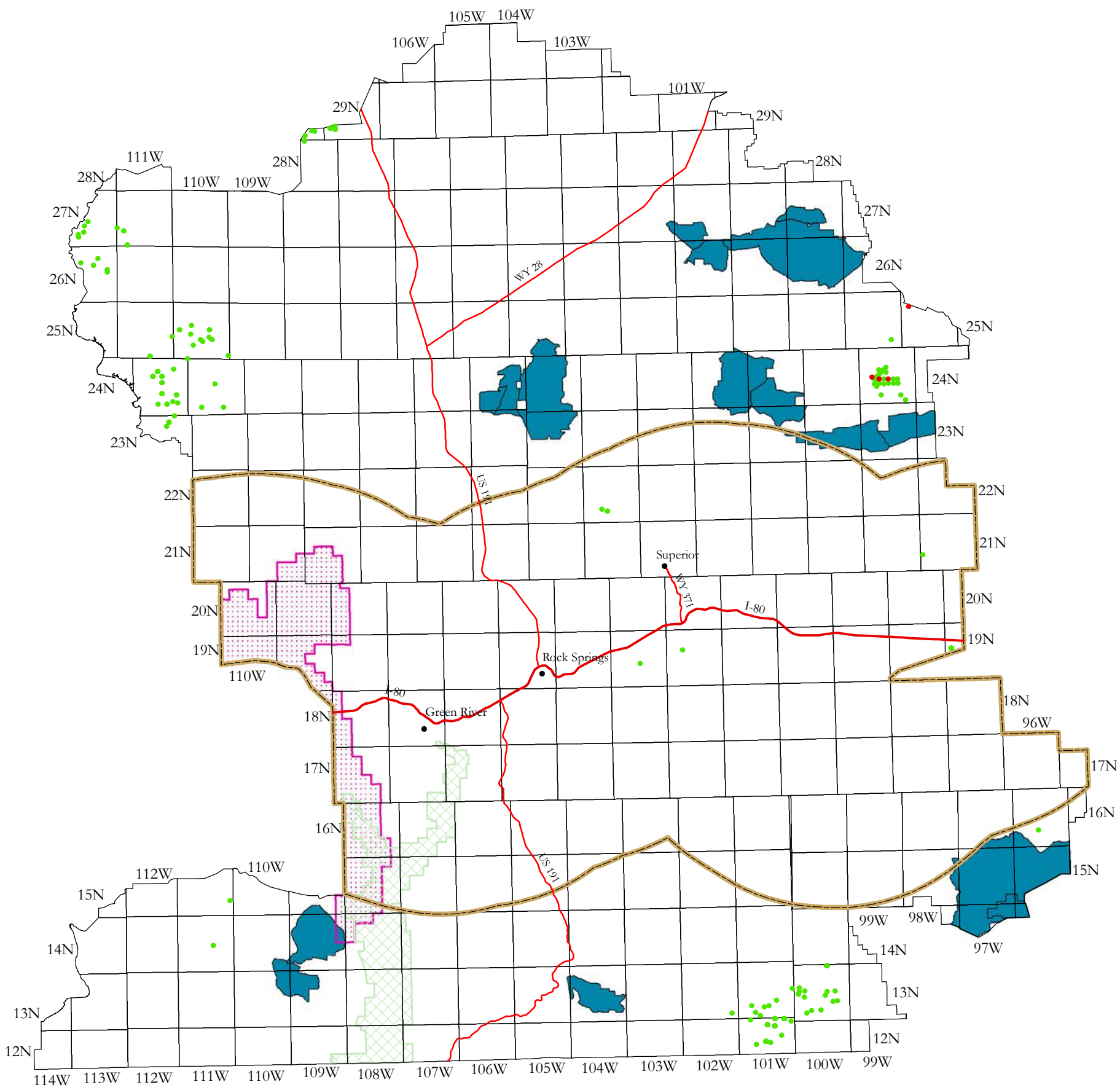
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 8c.

Location and initial classification of Rock Springs Planning Area active drilling permits as of April of 2012. Data from IHS Energy Group (2012).



Permits

- Coalbed Natural Gas
- Oil and Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

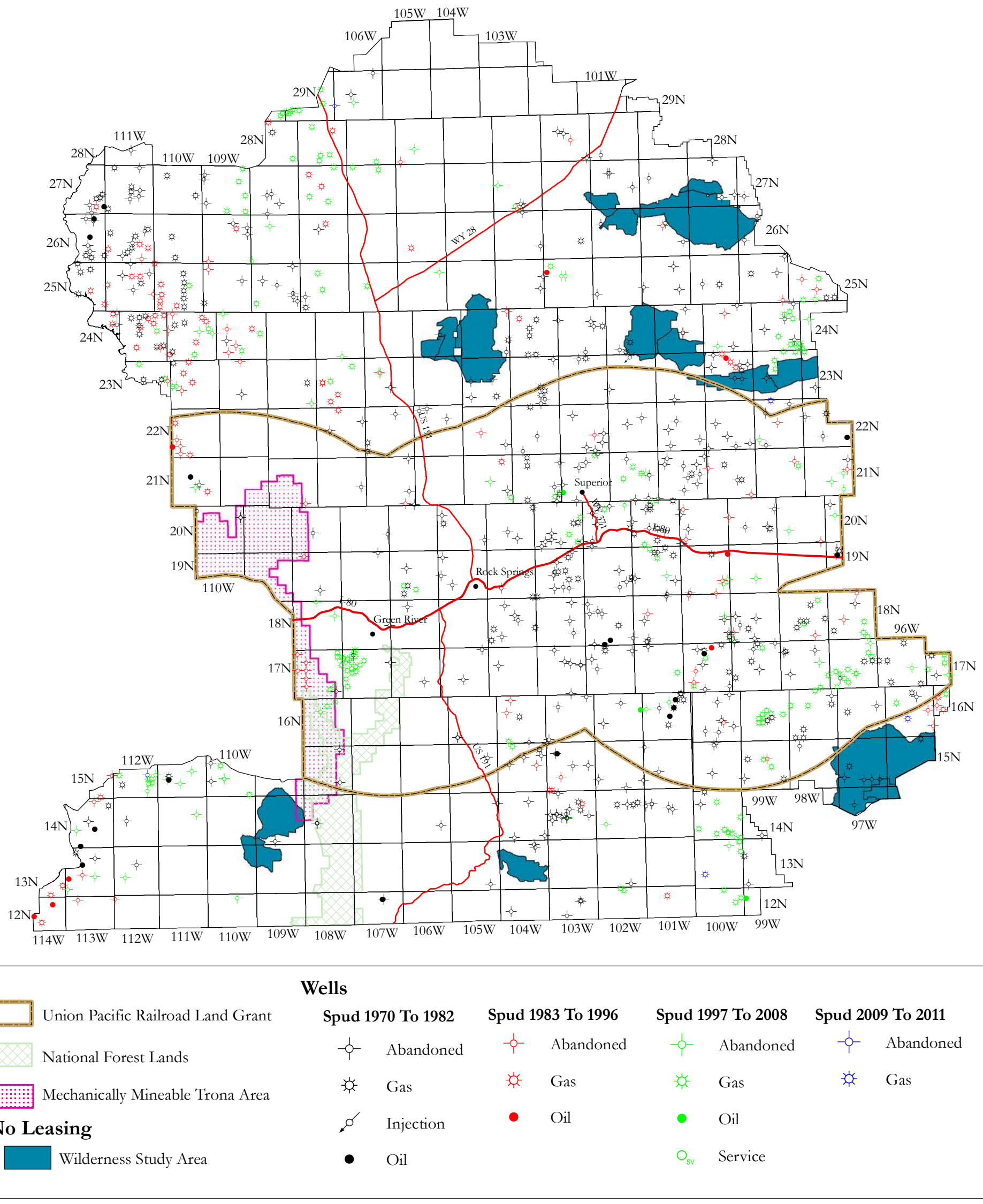
N

June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 9a.
Location and initial status of Rock Springs Planning Area conventional oil and gas wildcat wells spudded between January 1, 1970 and December 31, 2011. Data from IHS Energy Group (2012).



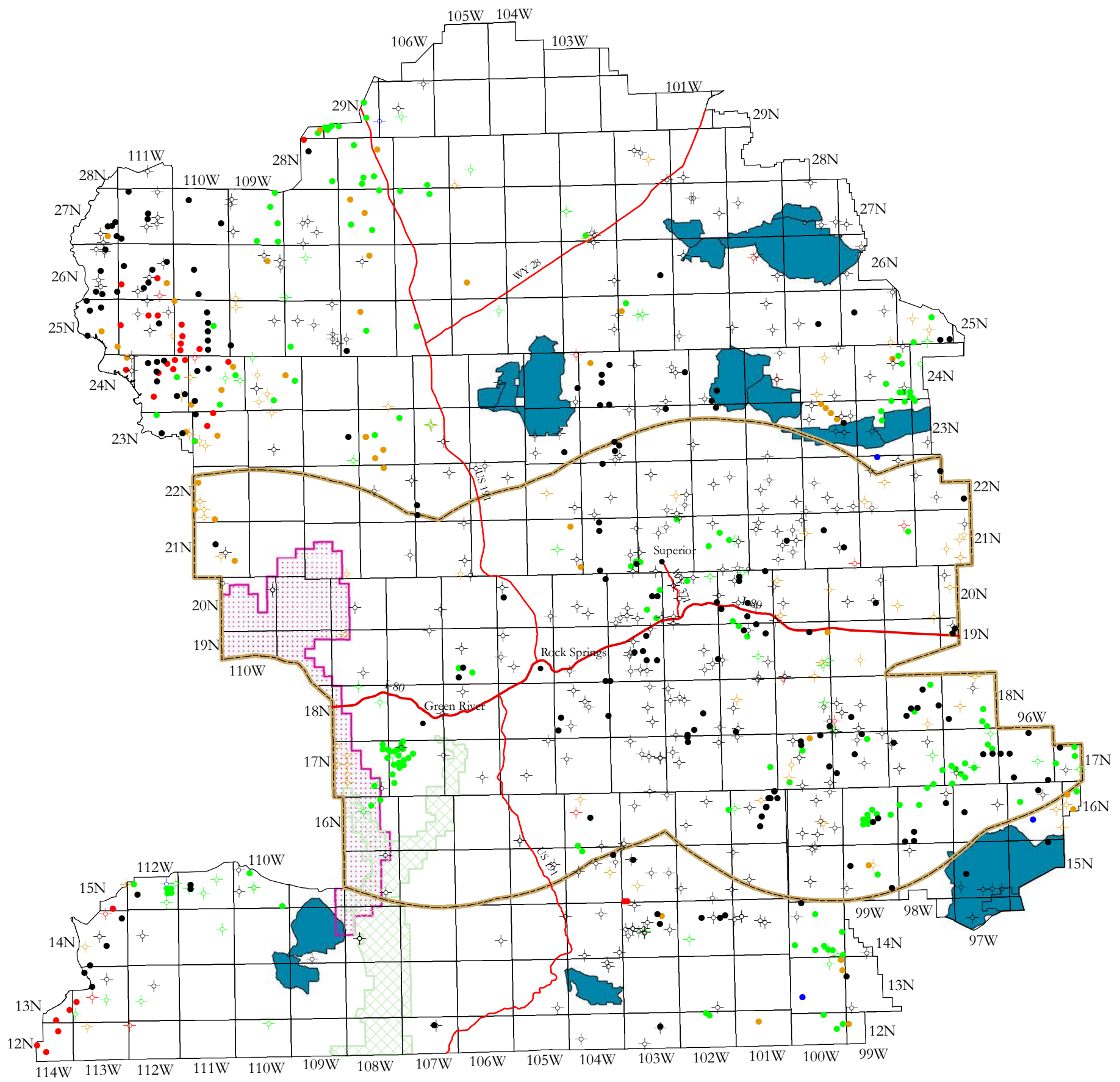
Wyoming State Office
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 9b.
Locations of successful and unsuccessful conventional wildcat oil and gas wells within the Rock Springs Planning Area for certain time periods between January 1, 1970 and December 31, 2011. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wells

Spud 1970 To 1982
Abandoned
Successful

Spud 1988 To 1997
Abandoned
Successful

Spud 2009 To 2011
Abandoned
Successful

Spud 1983 To 1987
Abandoned
Successful

Spud 1998 To 2008
Abandoned
Successful

Wyoming State Office
Reservoir Management Group

0 5 10 20 30 40 Miles
1:800,000

N

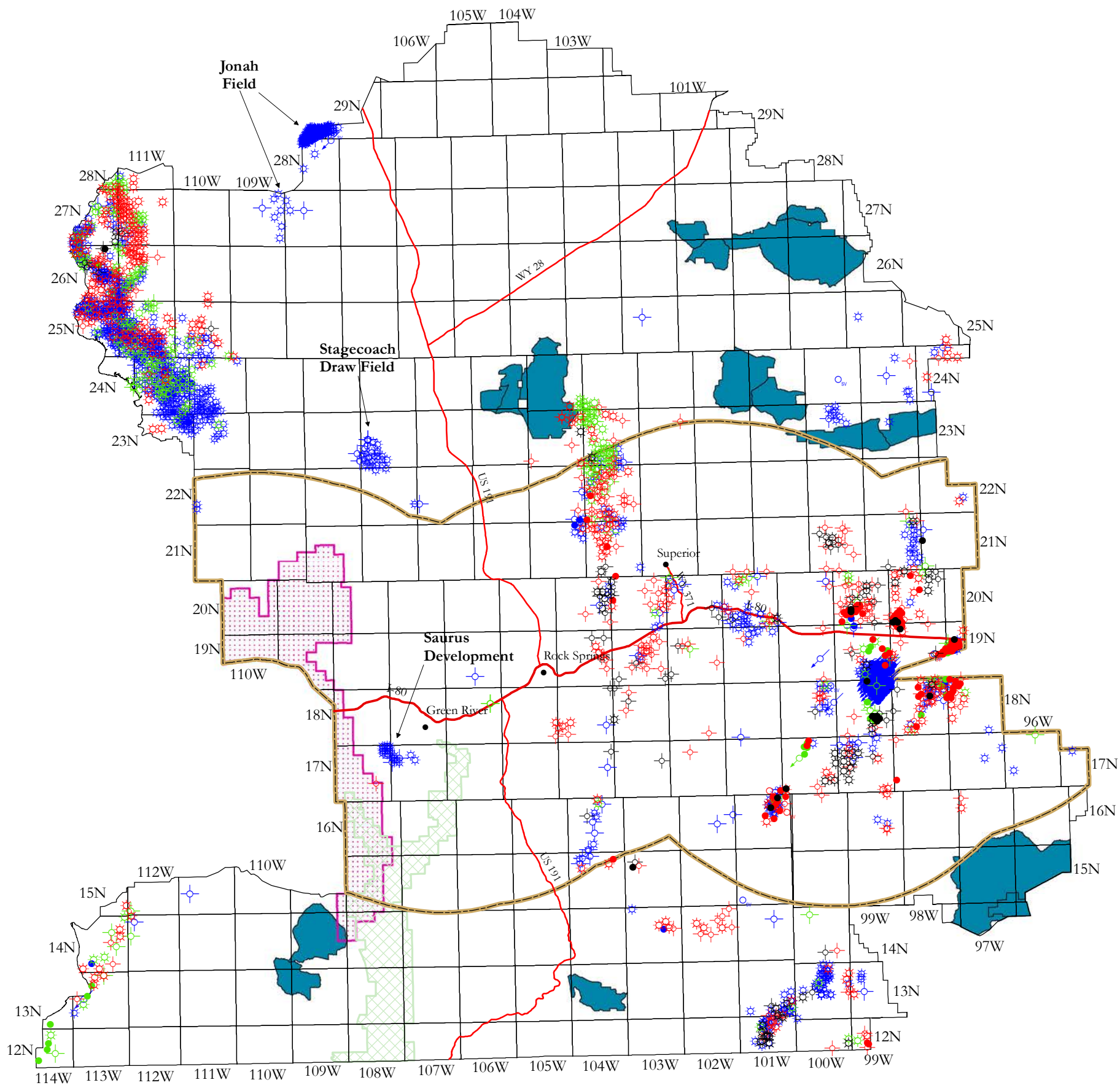
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 9c.

Location and initial status of Rock Springs Planning Area conventional oil and gas development wells spudded between January 1, 1970 and December 31, 2011.



Wells

Spud 1970 To 1973	Spud 1974 To 1983	Spud 1984 To 1991	Spud 1992 To 2011
Abandoned	Abandoned	Abandoned	Abandoned
Gas	Gas	Gas	Gas
Oil	Oil	Injection	Injection
	Service	Oil	Oil
			Service

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

0 5 10 20 30 40 Miles

1:800,000

Wyoming State Office

Reservoir Management Group

N

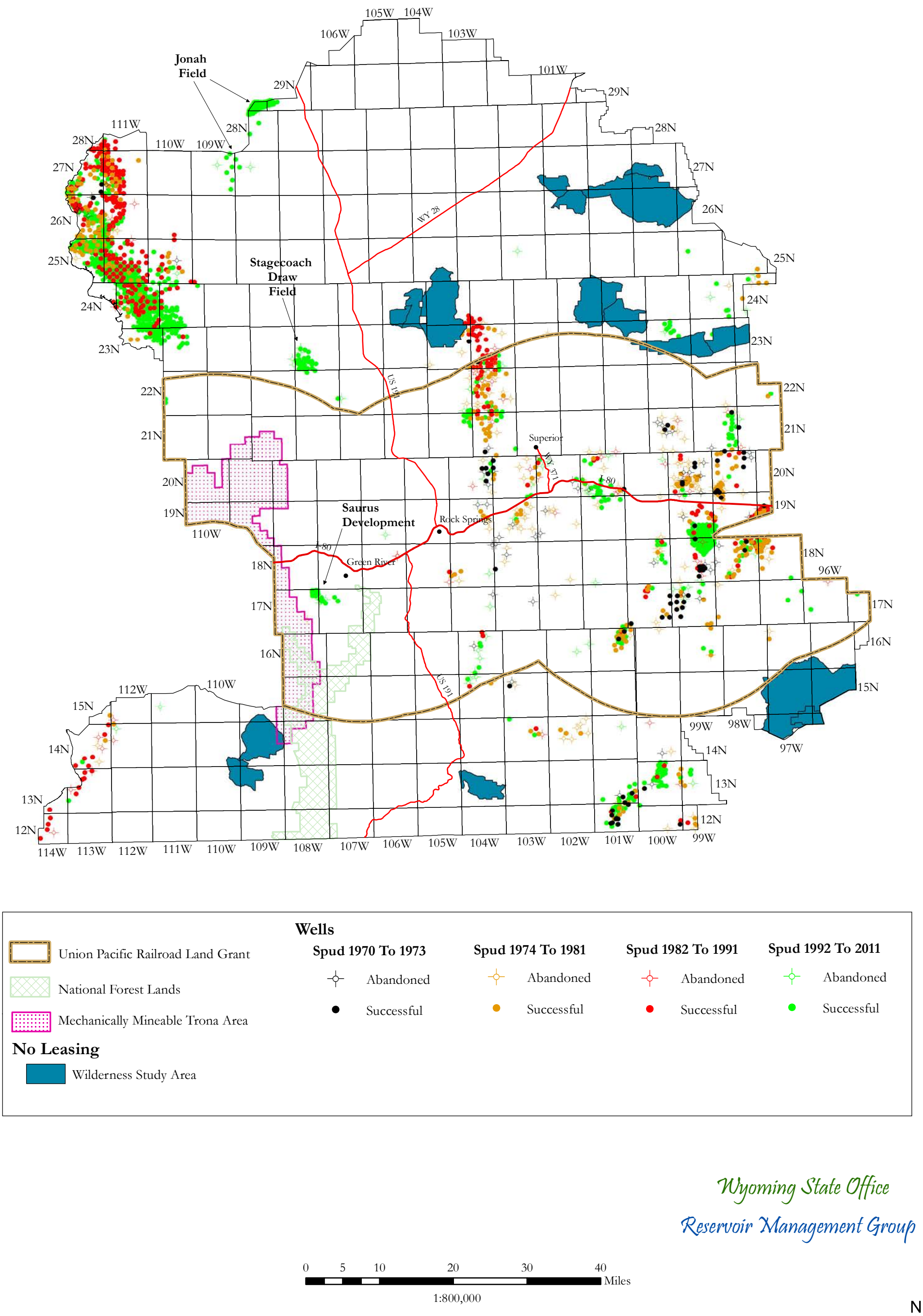
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 9d.

Locations of successful and unsuccessful conventional development oil and gas wells within the Rock Springs Planning Area for certain time periods between January 1, 1970 and December 31, 2011.



Wells

Spud 1970 To 1973	Spud 1974 To 1981	Spud 1982 To 1991	Spud 1992 To 2011
Abandoned	Abandoned	Abandoned	Abandoned
Successful	Successful	Successful	Successful

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

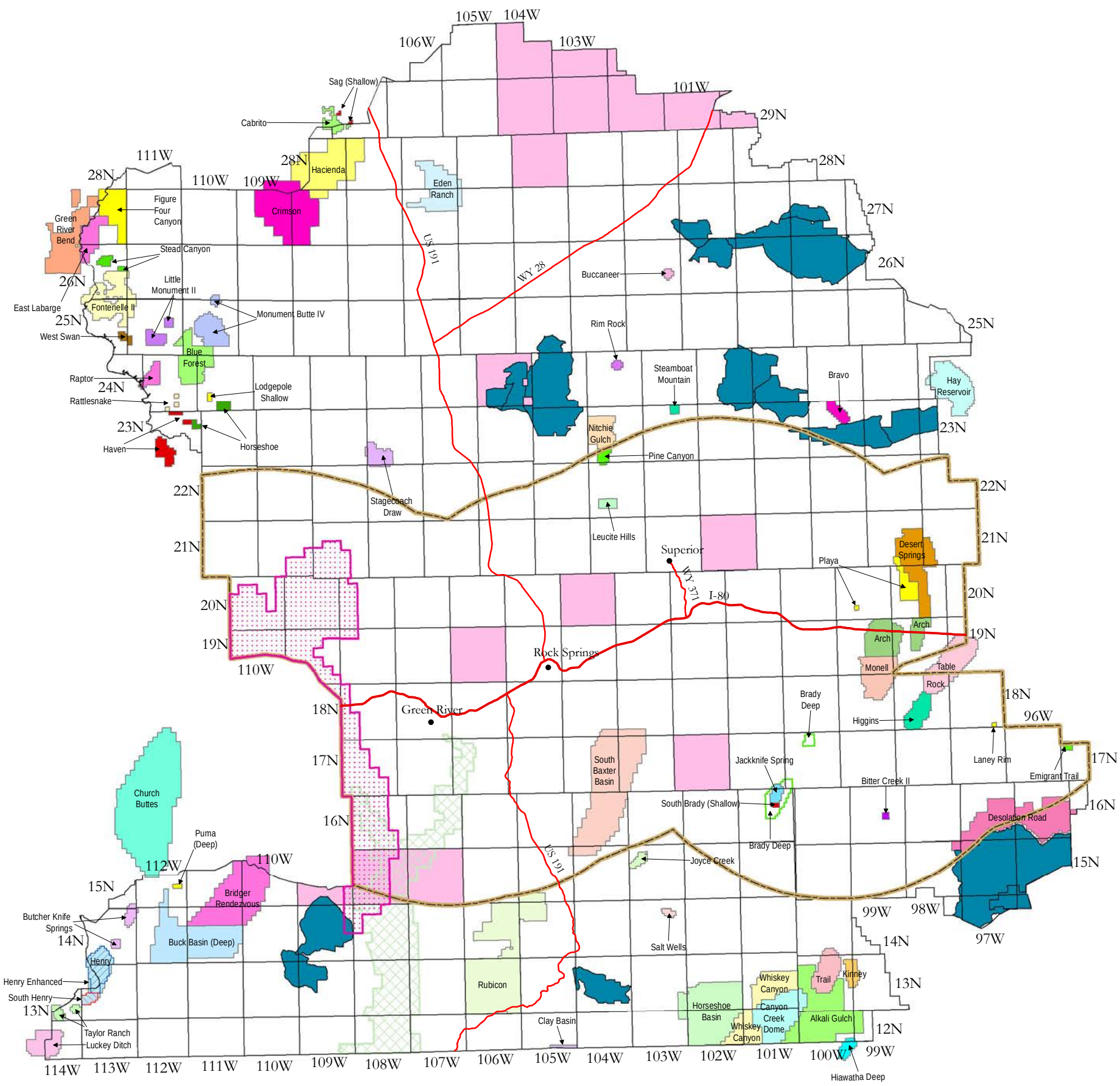
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 10.

Locations of active conventional oil and gas units and townships with no historical units within the Rock Springs Planning Area. Data from Bureau files.



No Historical Units

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

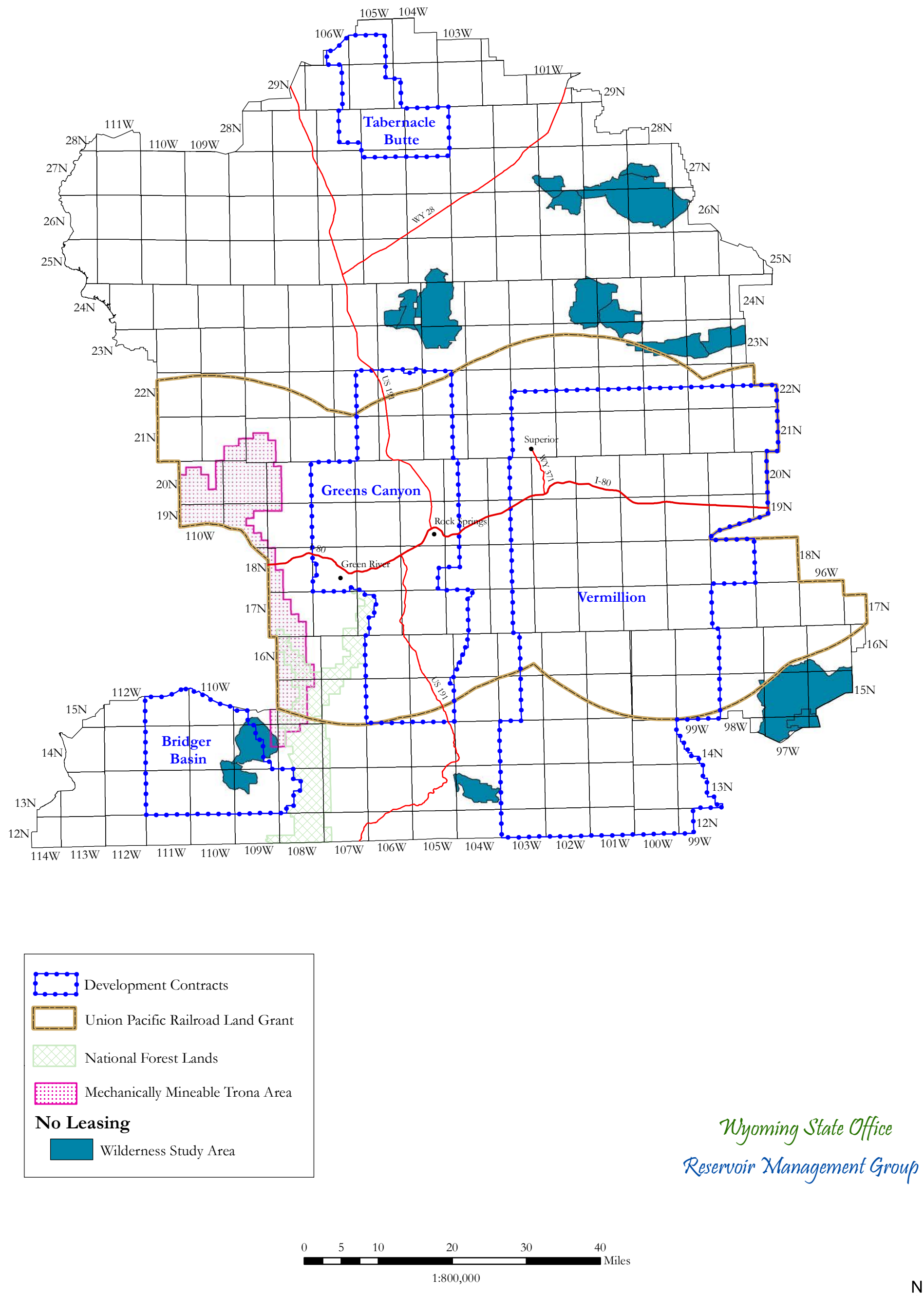
August, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification. This map is produced in cooperation with Premier Data Services, Arvada Colorado.

Figure 11.

Locations of terminated development contracts within the Rock Springs Planning Area. Data from Bureau files.

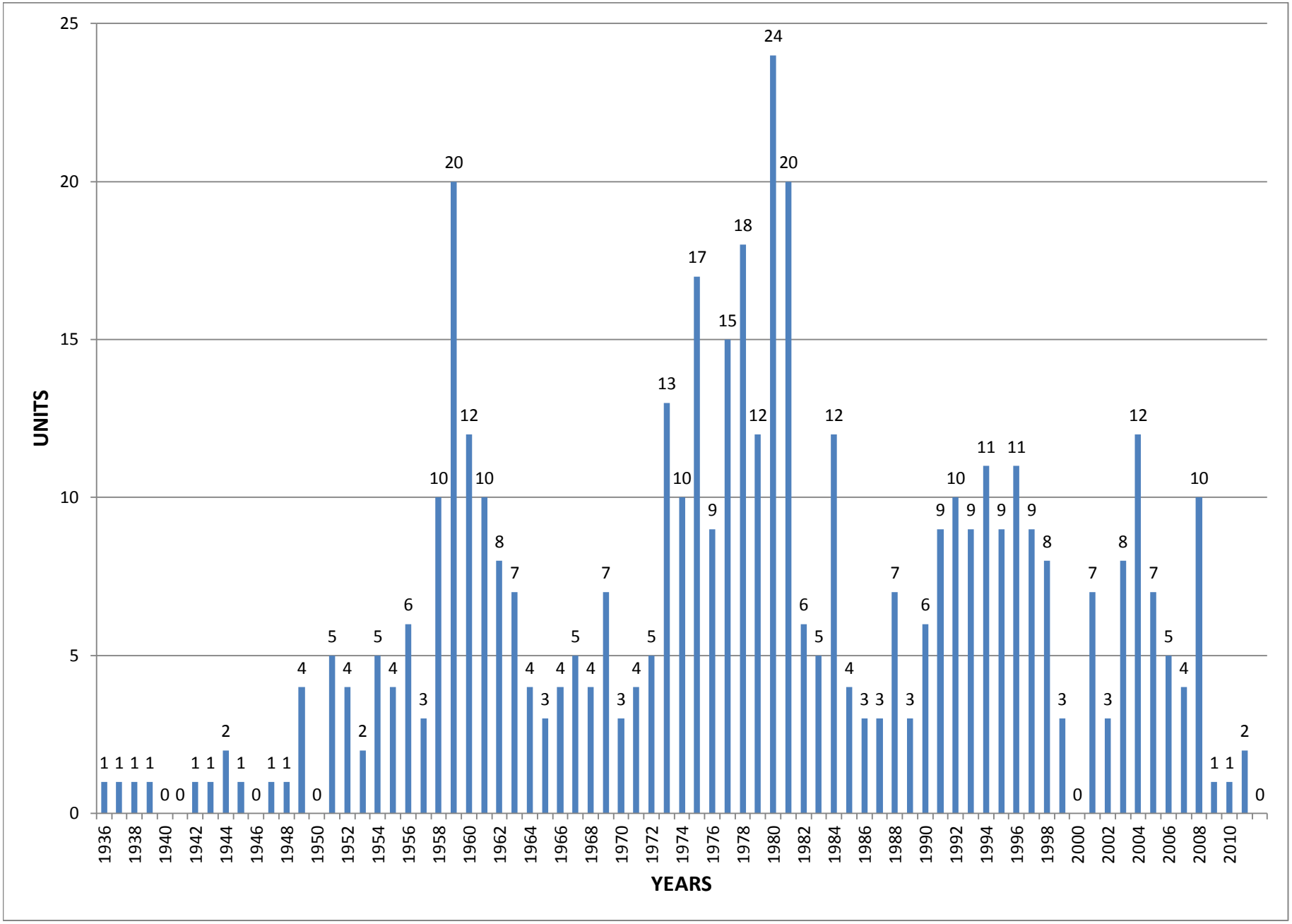


June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 12. Active and closed units, by year, within Rock Springs Planning Area. Data from Bureau files.



Wyoming State Office
Reservoir Management Group

Figure 13. Wells spudded by year within the Rock Springs Planning Area. Data from IHS Energy Group (2012).

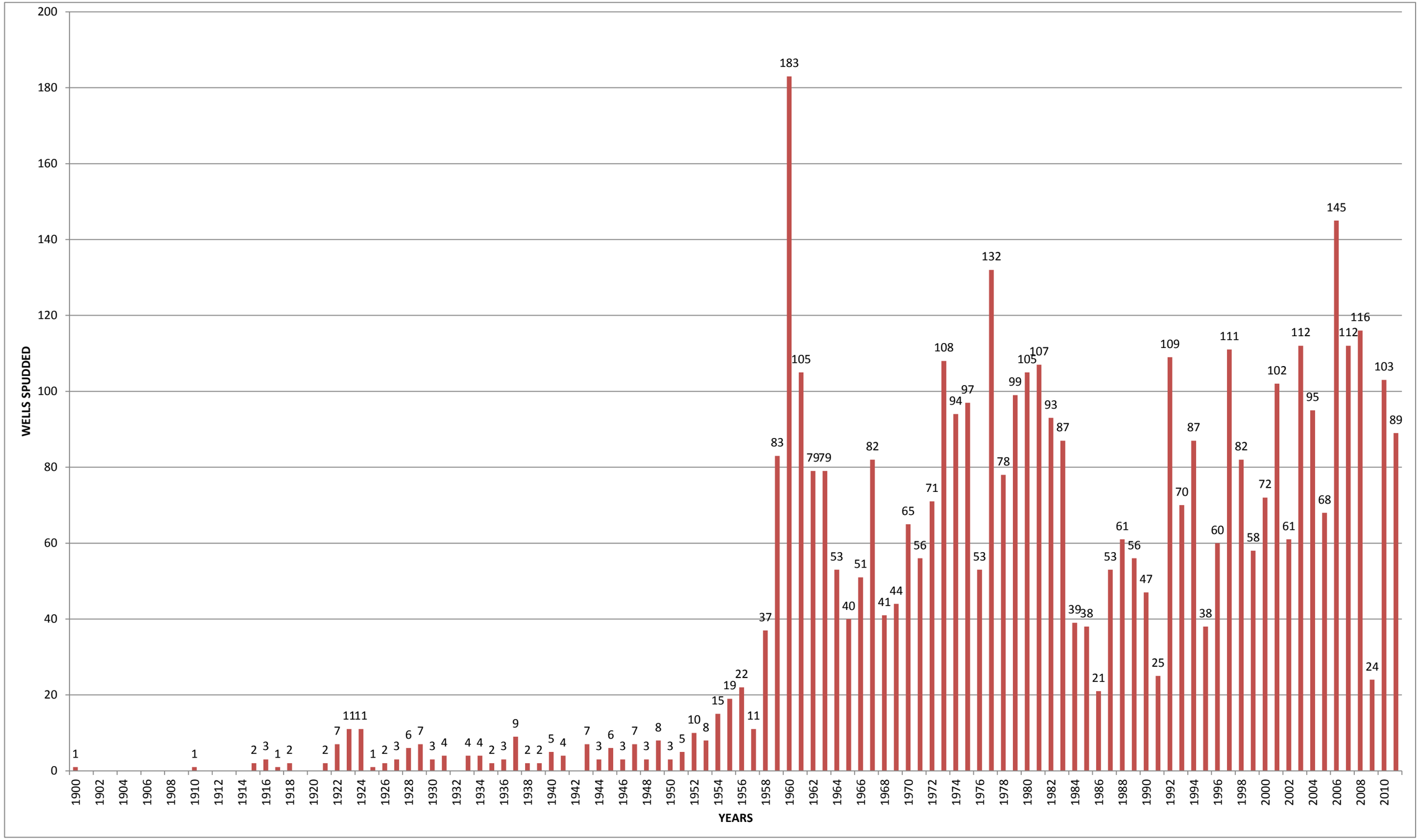
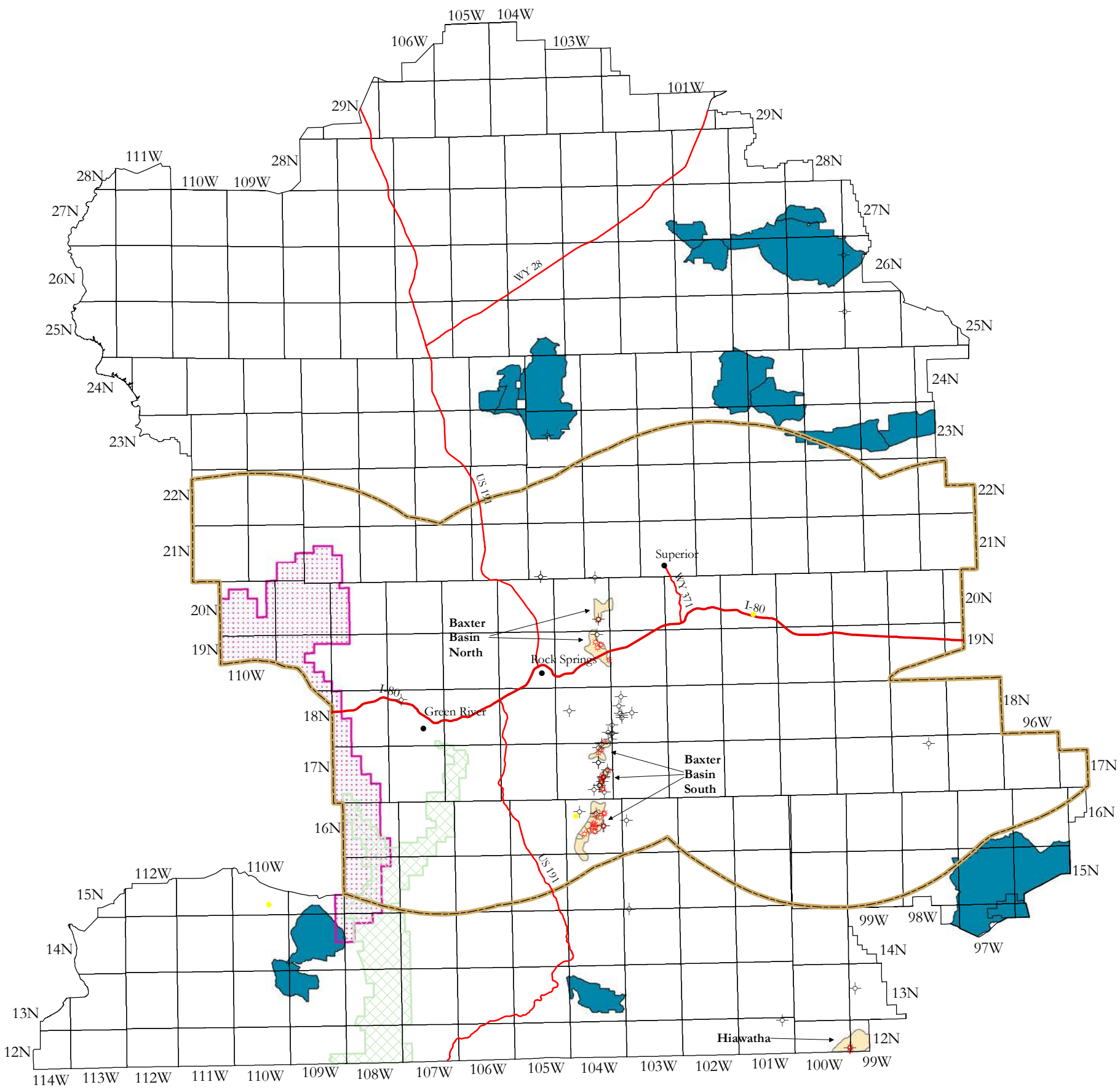


Figure 14a.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1900 through 1935. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Oil and Gas Fields

Wells

Abandoned

Gas

Carbon Dioxide

Injection

Oil

Permit

Service/Observation/Pilot

Spudded

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

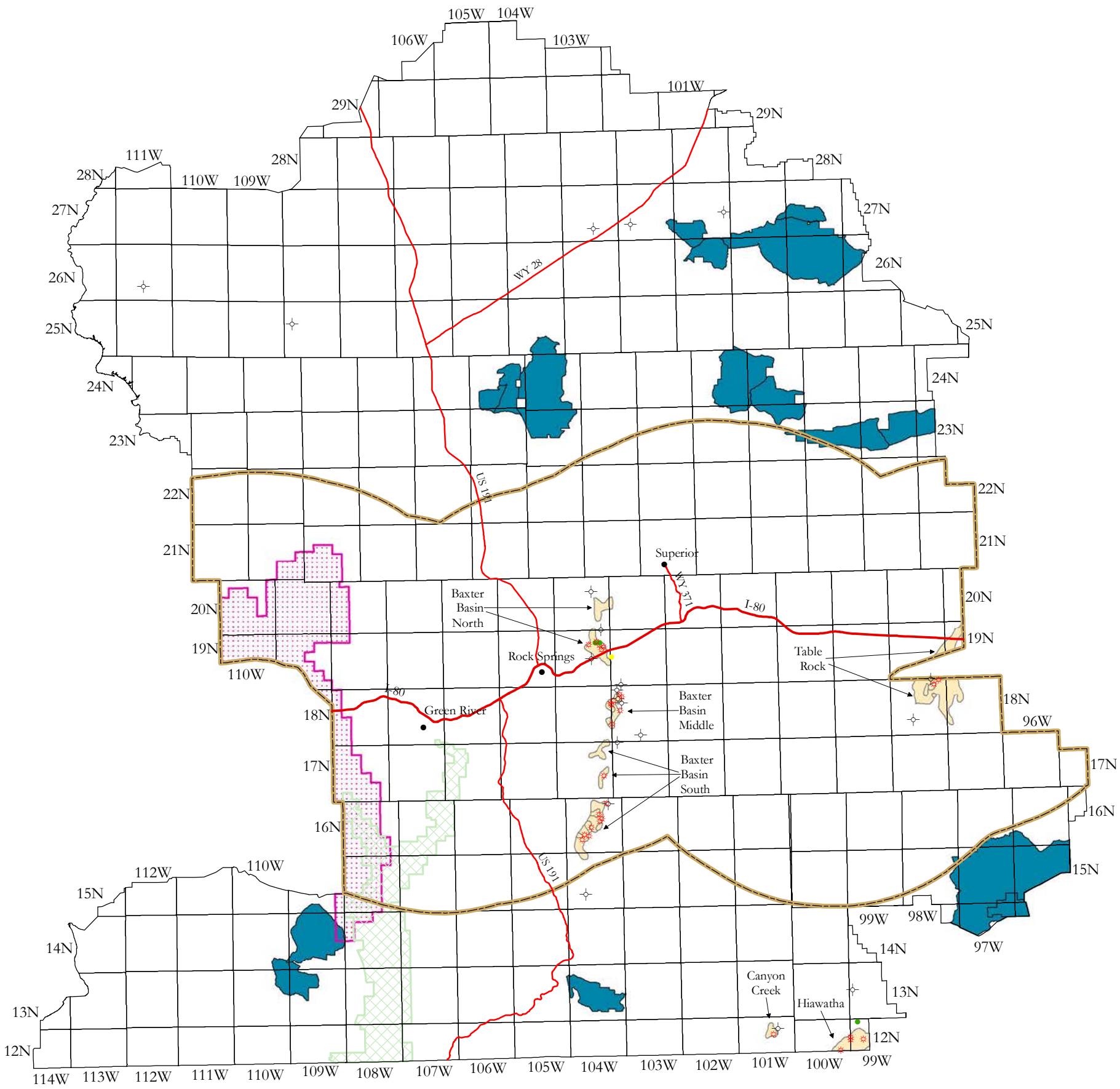
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 14b.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1936 through 1948. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Oil and Gas Fields

Wells

Abandoned

Gas

Carbon Dioxide

Injection

Oil

Permit

Service/Observation/Pilot

Spudded

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

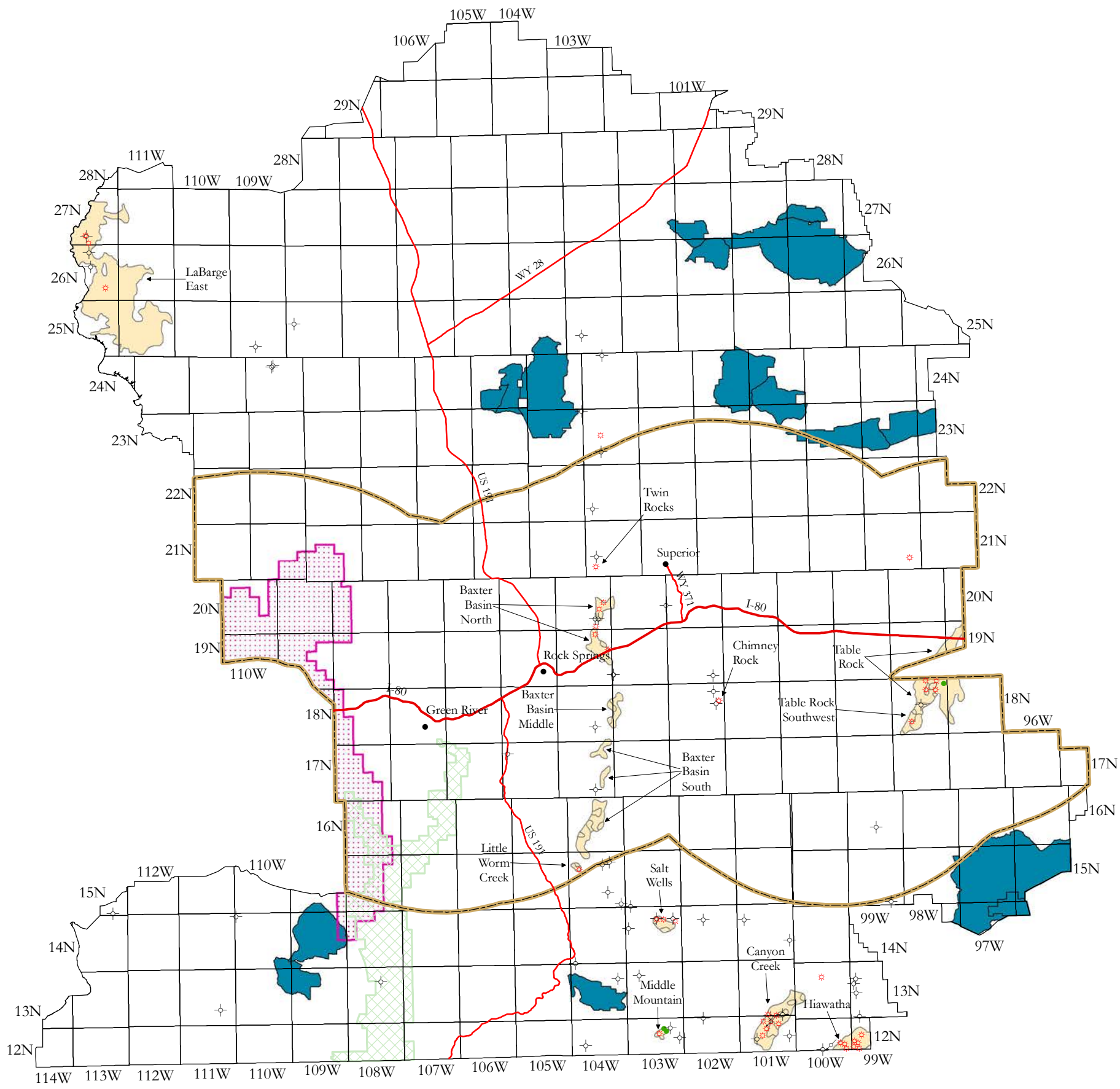
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 14c.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1949 through 1957. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Oil and Gas Fields

Wells

Abandoned

Gas

Carbon Dioxide

Injection

Oil

Permit

Service/Observation/Pilot

Spudded

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

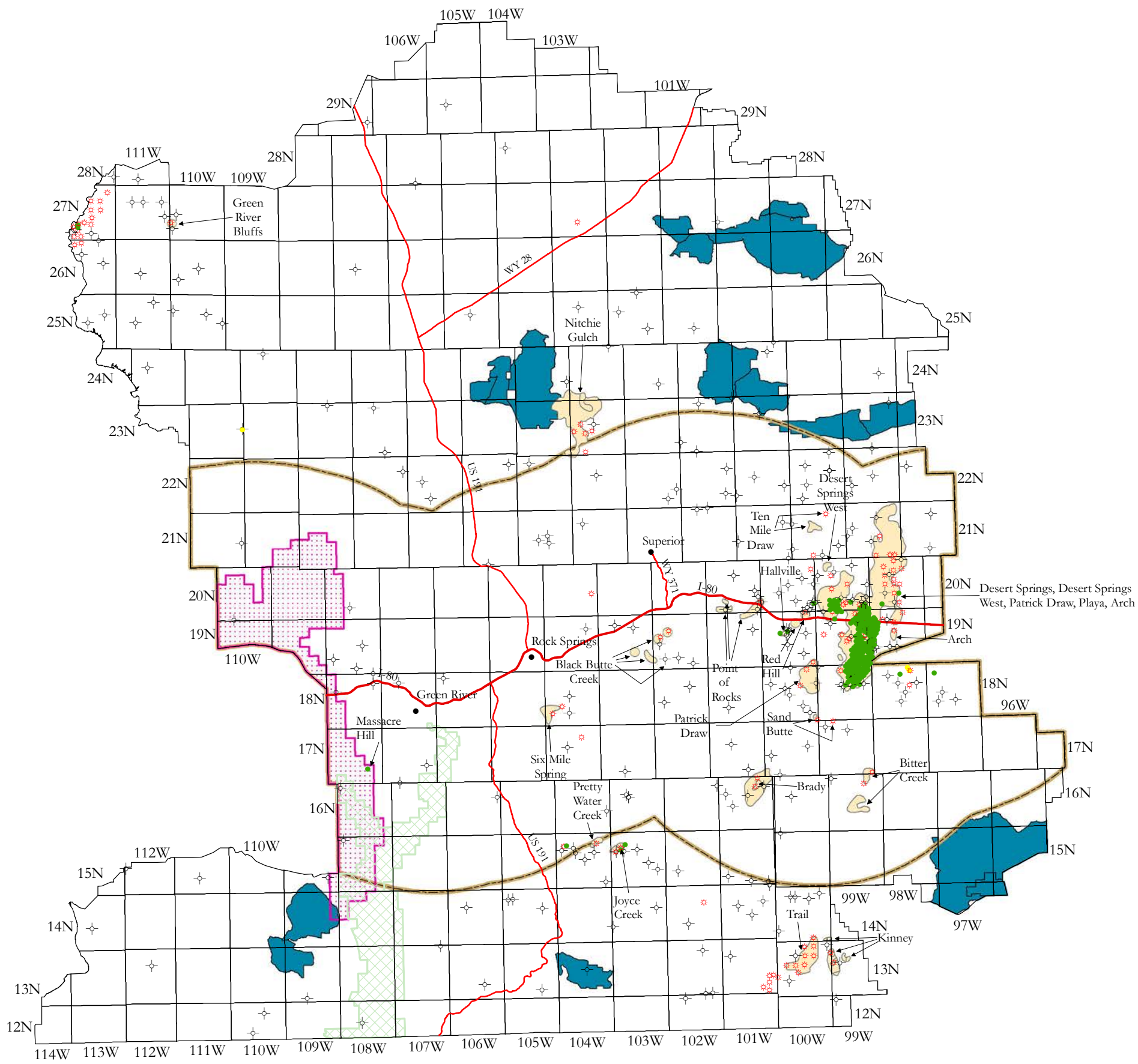
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 14d.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1958 through 1963. Data from IHS Energy Group (2012).



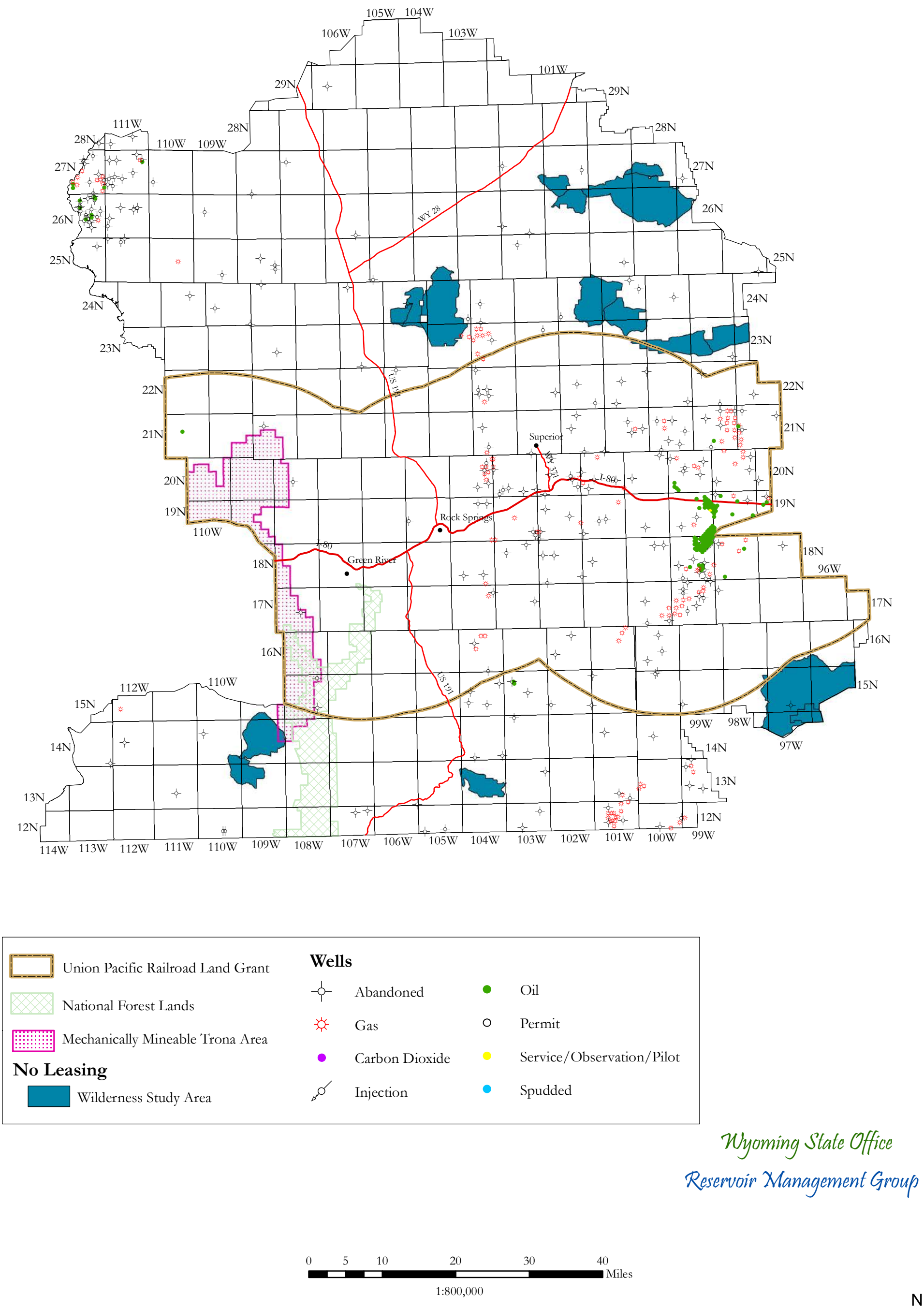
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 14e.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1964 through 1972. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

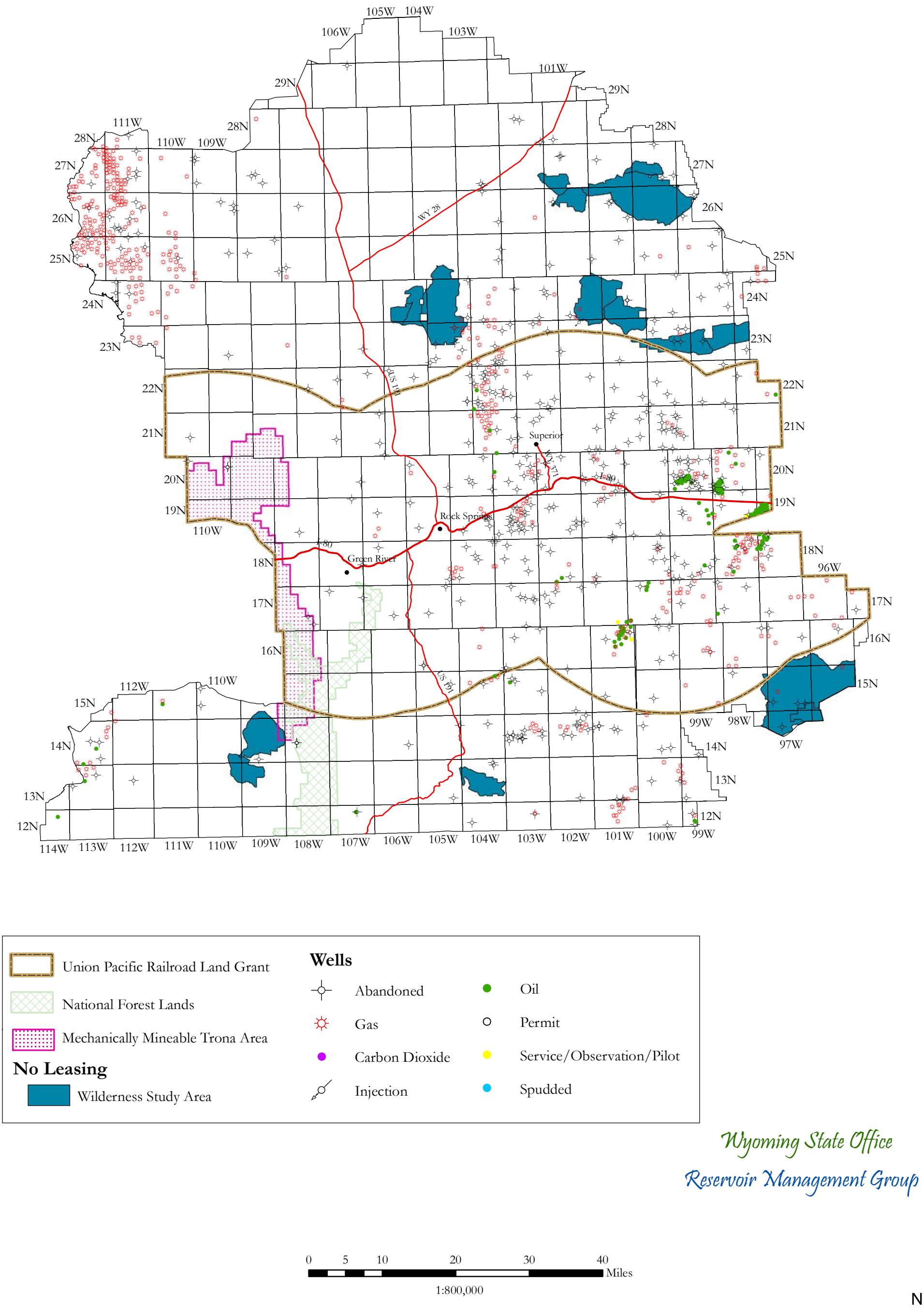
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 14f.

Location and initial status of all conventional oil and gas wells drilled within the Rock Springs Planning Area from 1973 through 1983. Data from IHS Energy Group (2012).



Wyoming State Office
Reservoir Management Group

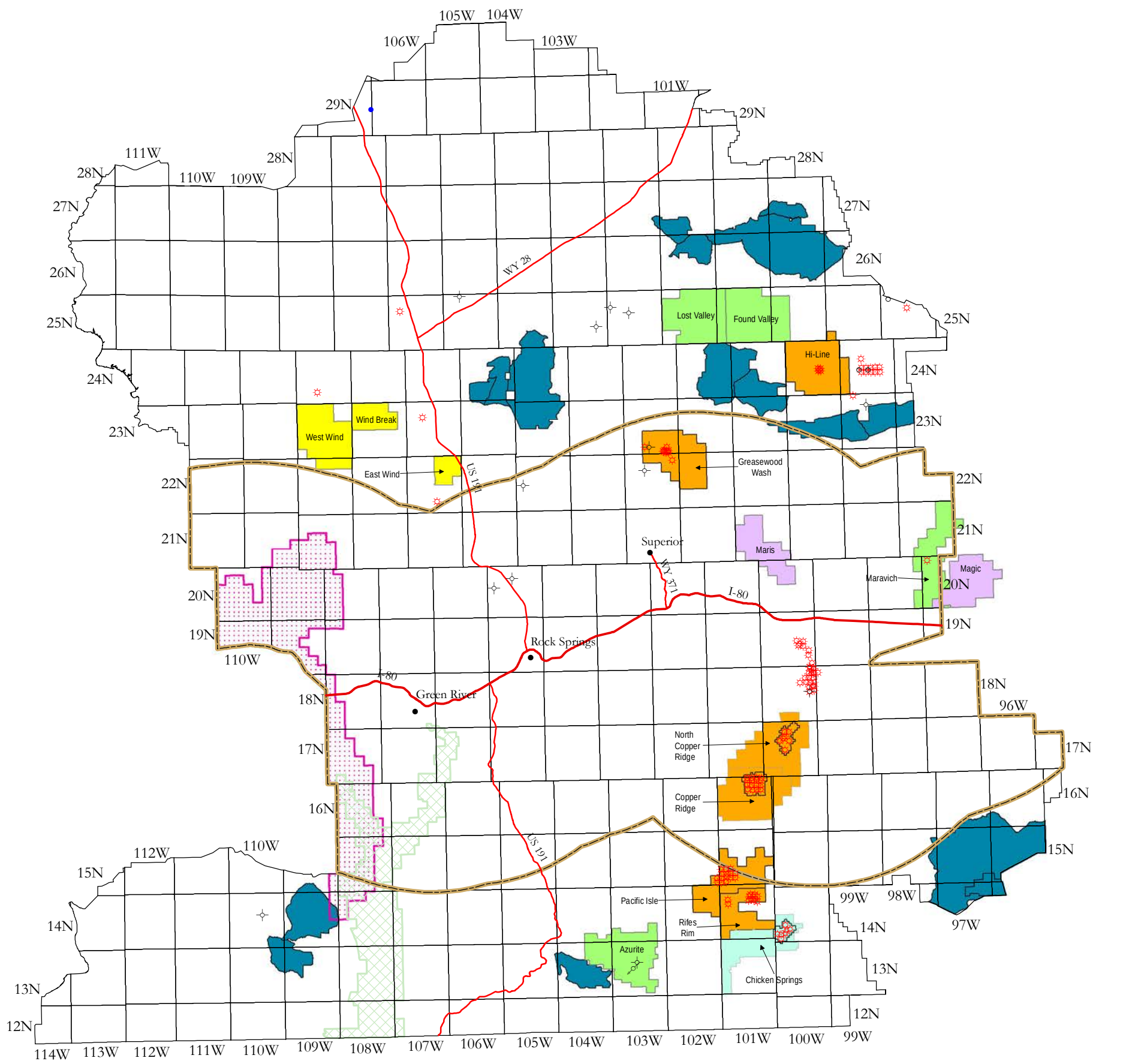
September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 15.

Location of active and closed coalbed natural gas units and initial completion status of wells within the Rock Springs Planning Area. Unit data from Bureau files and well data from IHS Energy Group (2012).



Wyoming State Office
Reservoir Management Group

September, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification. This map is produced in cooperation with Premier Data Services, Arvada Colorado.

Figure 16. Coalbed natural gas wells spudded by year within the Rock Springs Planning Area. Data from IHS Energy Group (2012).

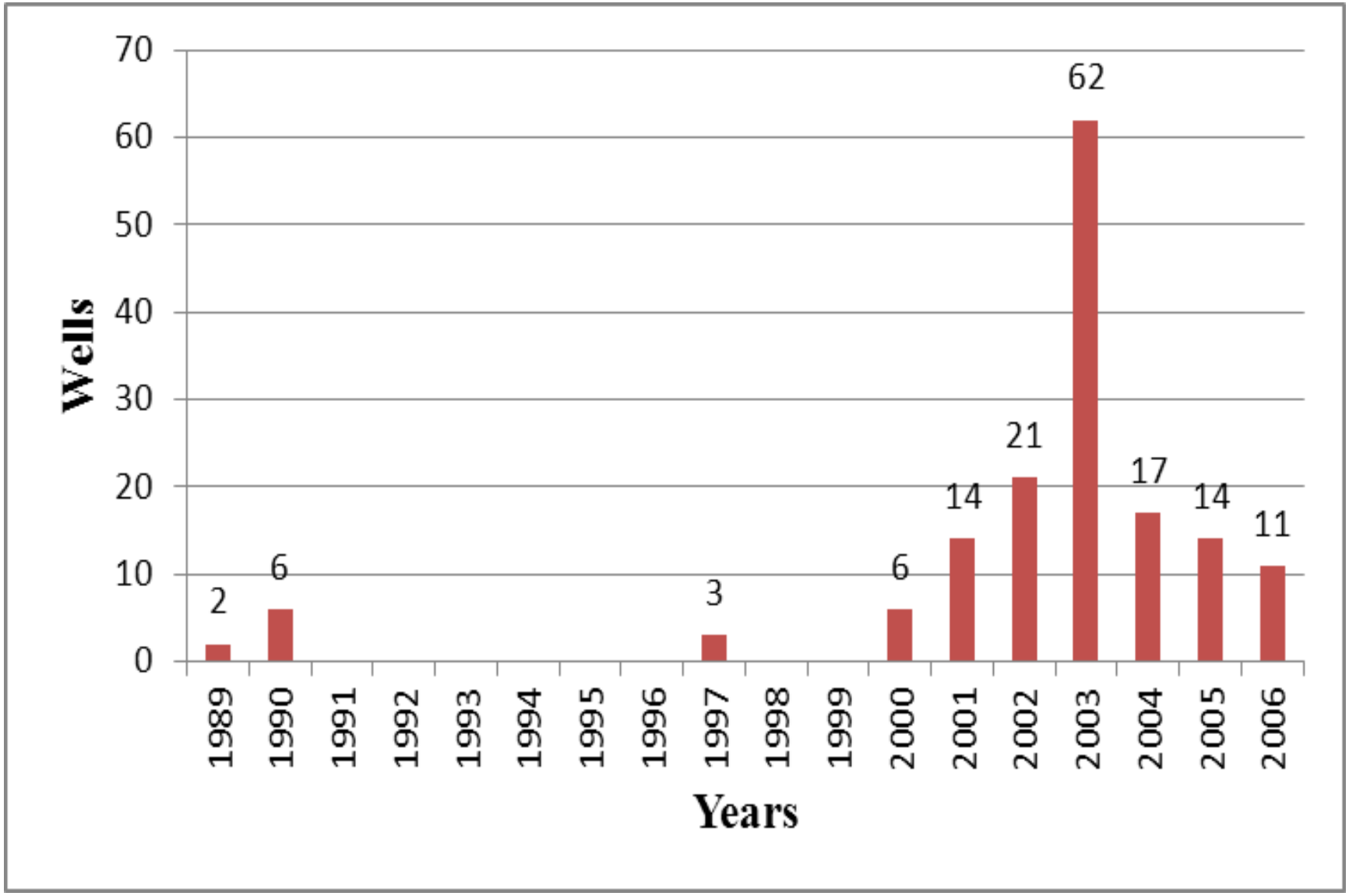
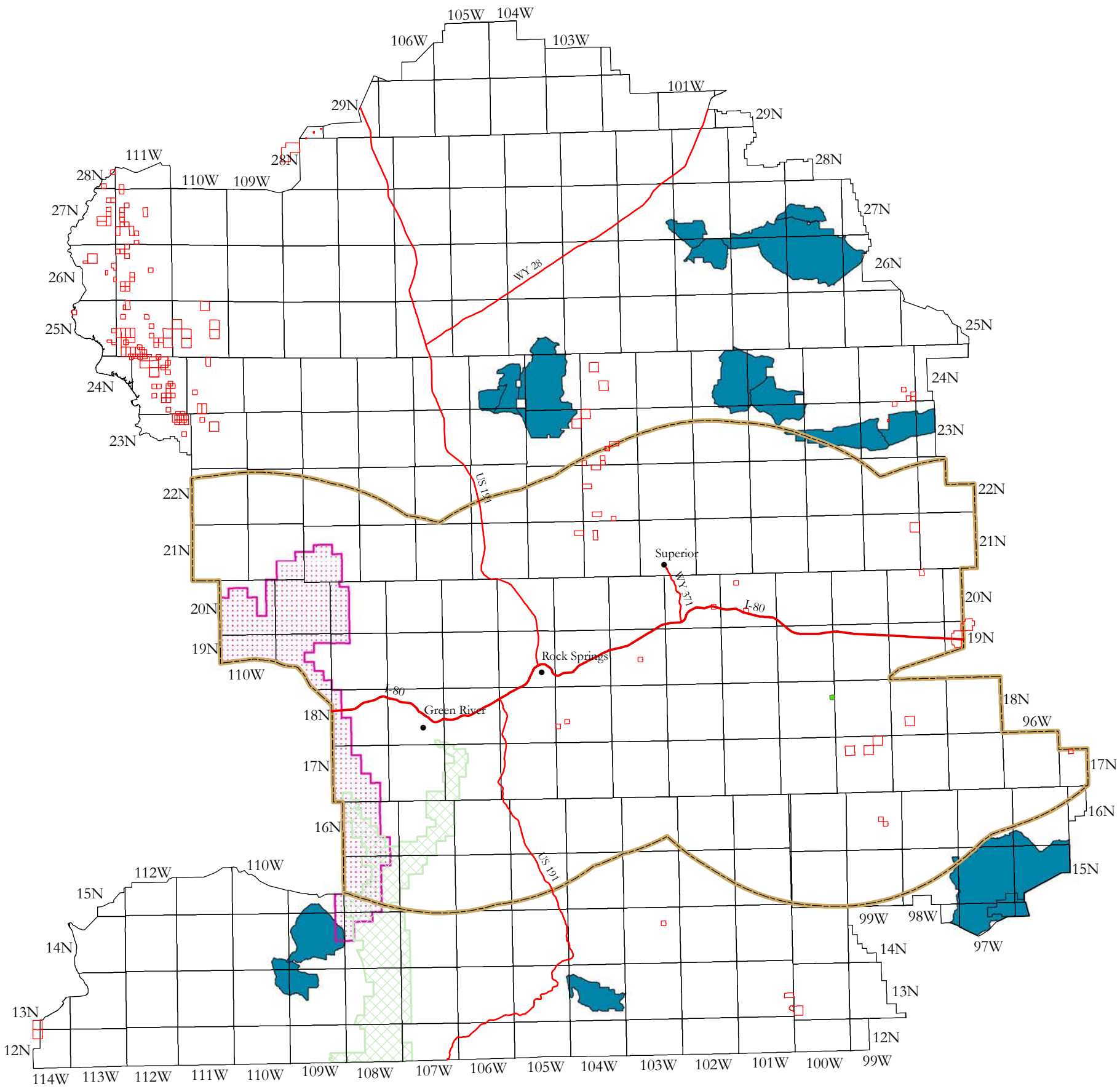


Figure 17.

Location of conventional and coalbed natural gas communitization agreements within the Rock Springs Planning Area. Data from Bureau files.



Communitization Agreements

- Coalbed Natural Gas
- Conventional Oil and Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

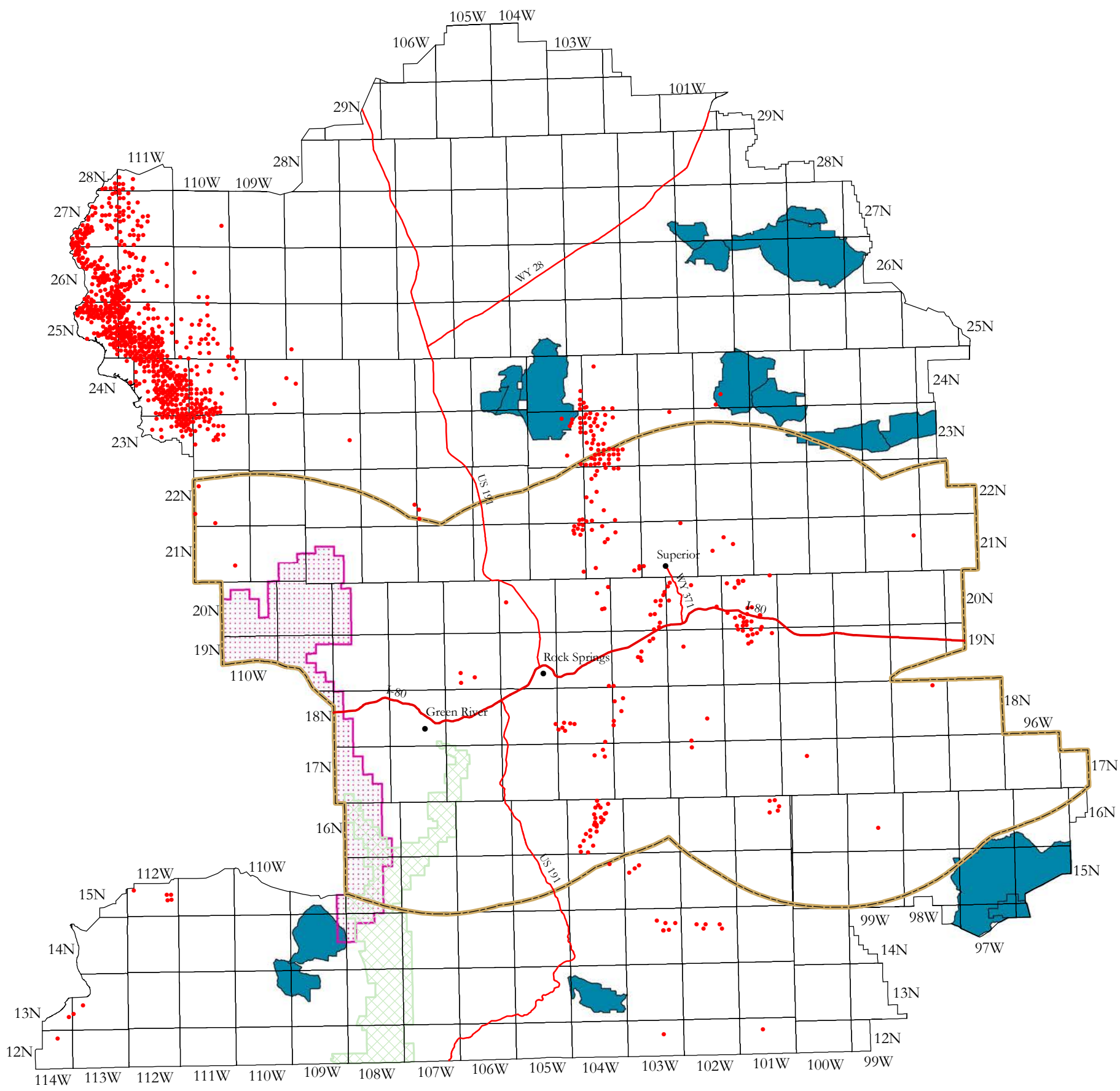
August, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18a.

Locations of all wells completed in the Cretaceous Frontier Formation within the Planning Area. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

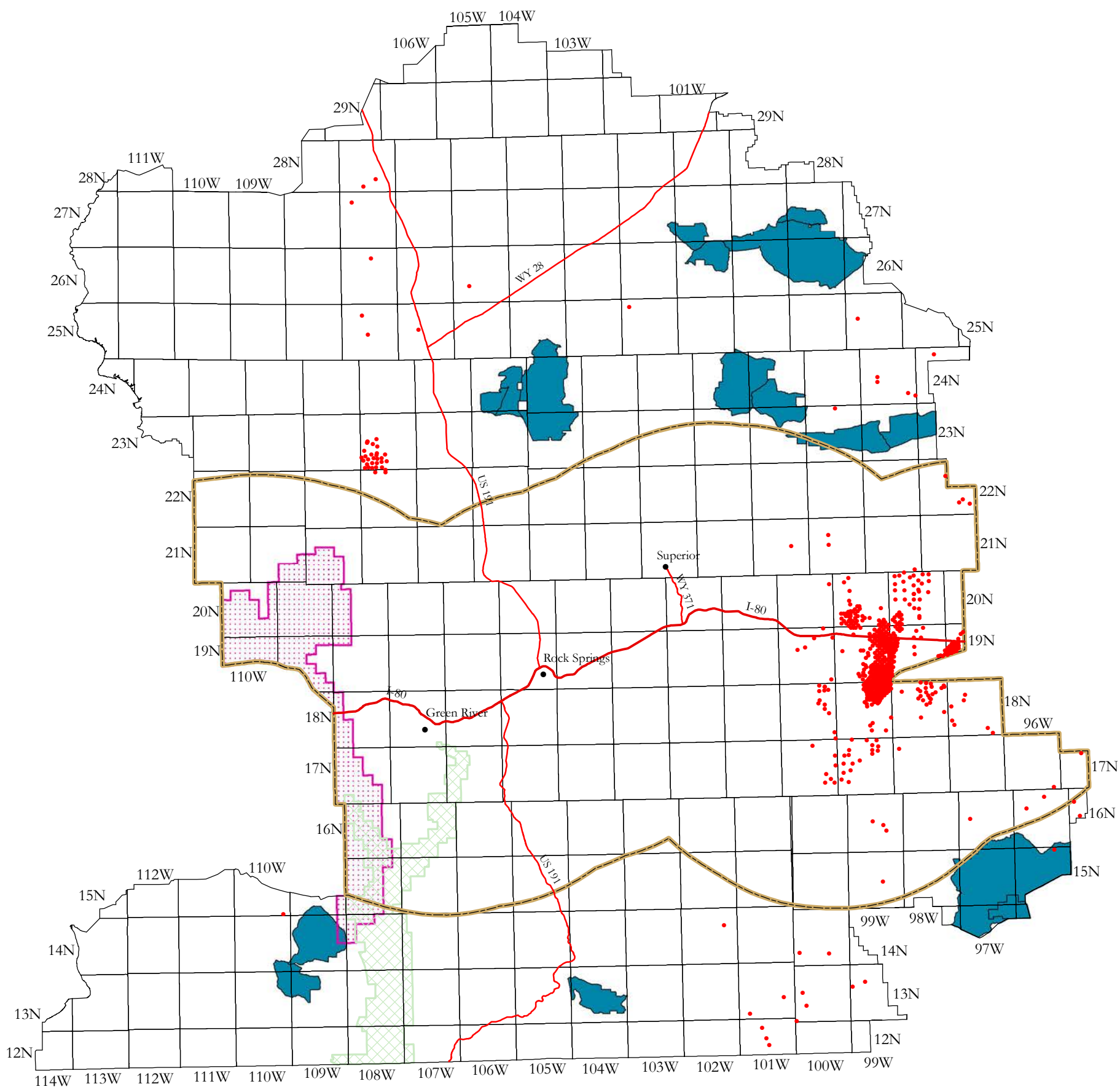
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18b.

Locations of all wells completed in the Cretaceous Almond Formation within the Planning Area. Data from IHS Energy Group (2012).



Wells

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

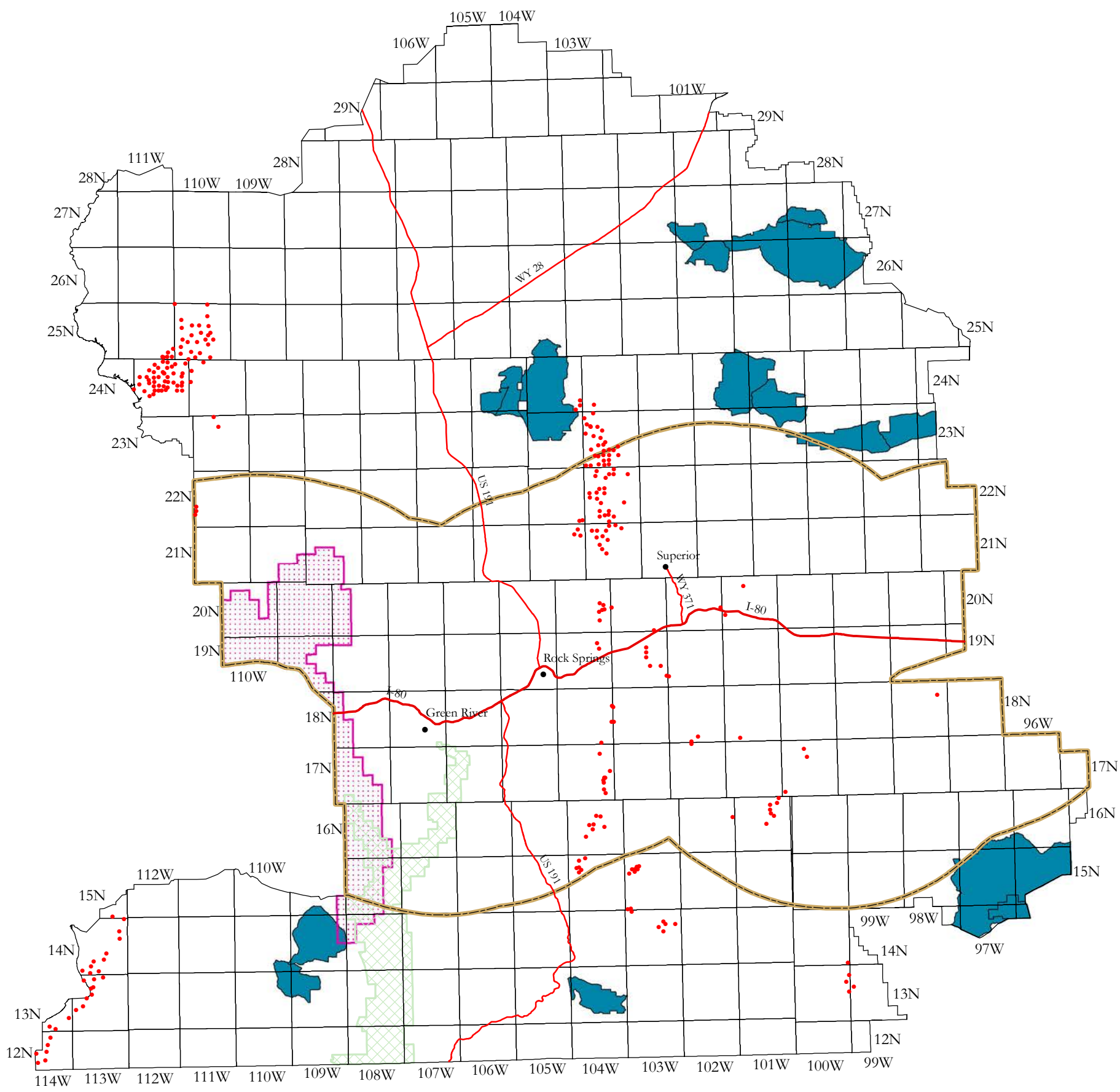
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18c.

Locations of all wells completed in the Cretaceous Dakota (Lakota) Formation within the Planning Area. Data from IHS Energy Group (2012).



Wells

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

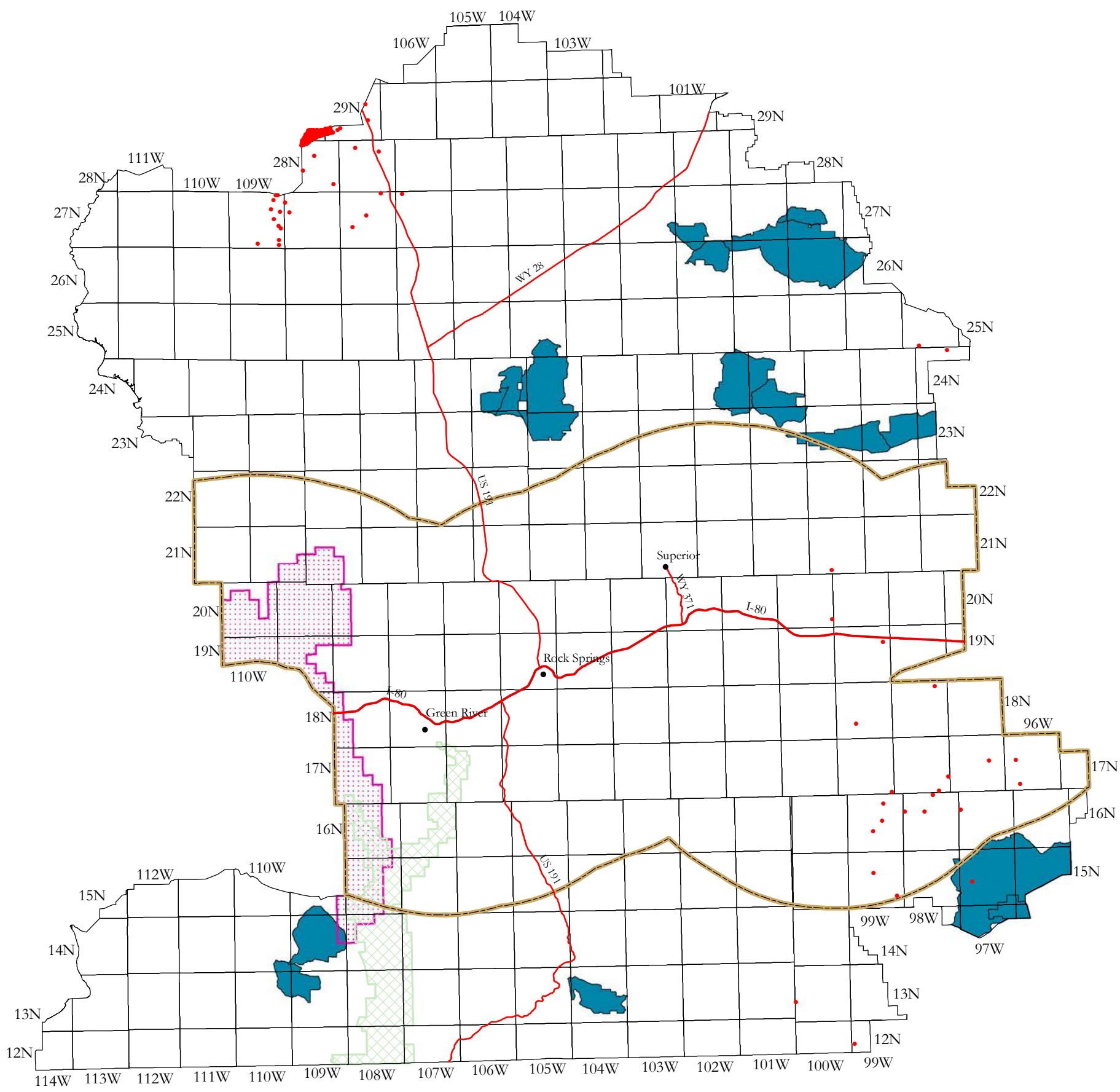
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18d.

Locations of all wells completed in the Cretaceous Lance Formation within the Planning Area. Data from IHS Energy Group (2012).



Wells

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

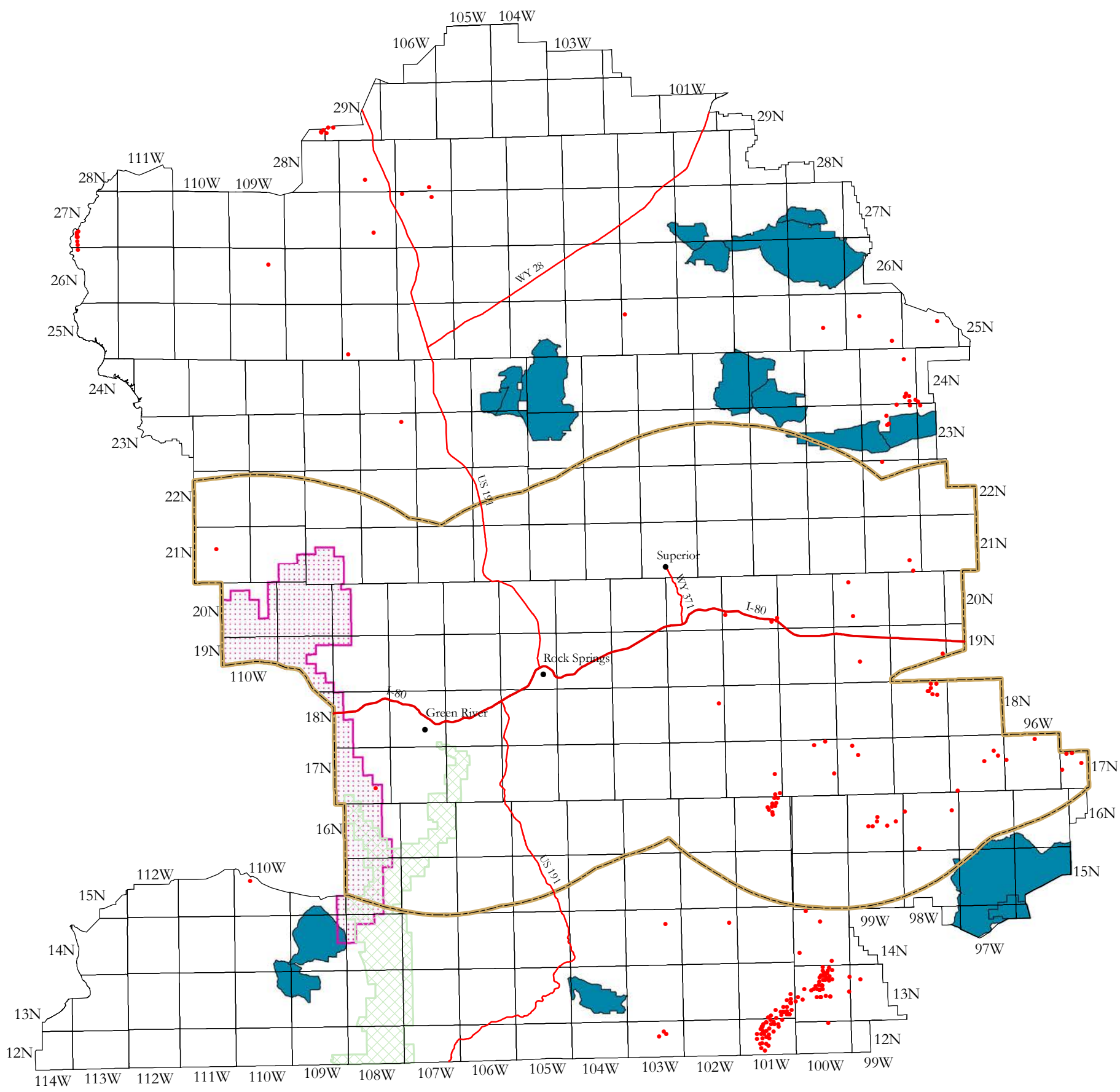
N

October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18e.
Locations of all wells completed in the Cretaceous Mesaverde Group (excluding the Almond Formation) within the Planning Area. Data from IHS Energy Group (2012).



Wells

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office
Reservoir Management Group

0 5 10 20 30 40 Miles
1:800,000

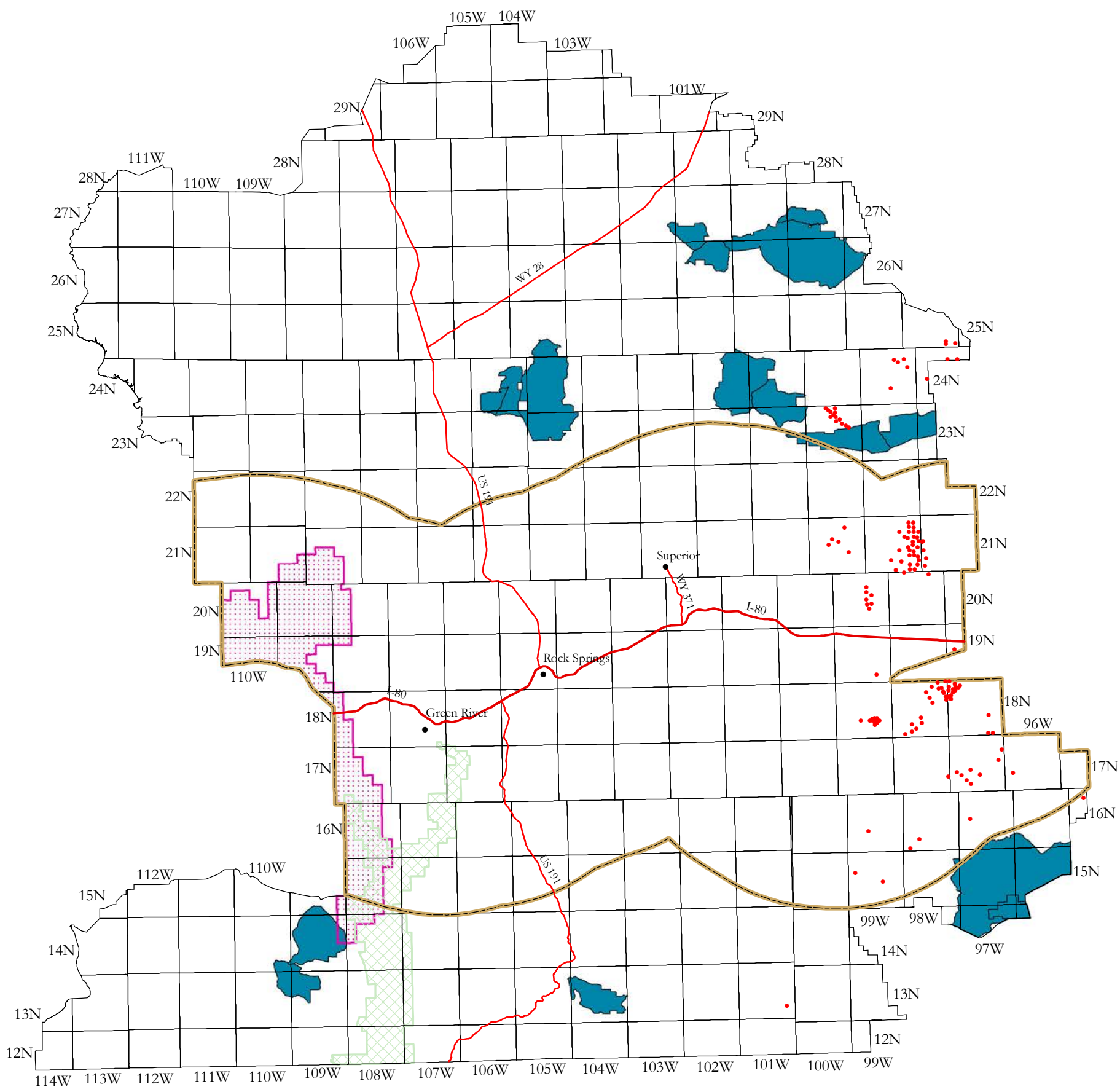
N

October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18f.
Locations of all wells completed in the Cretaceous Lewis Shale Formation within the Planning Area. Data from IHS Energy Group (2012).



Wells

Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

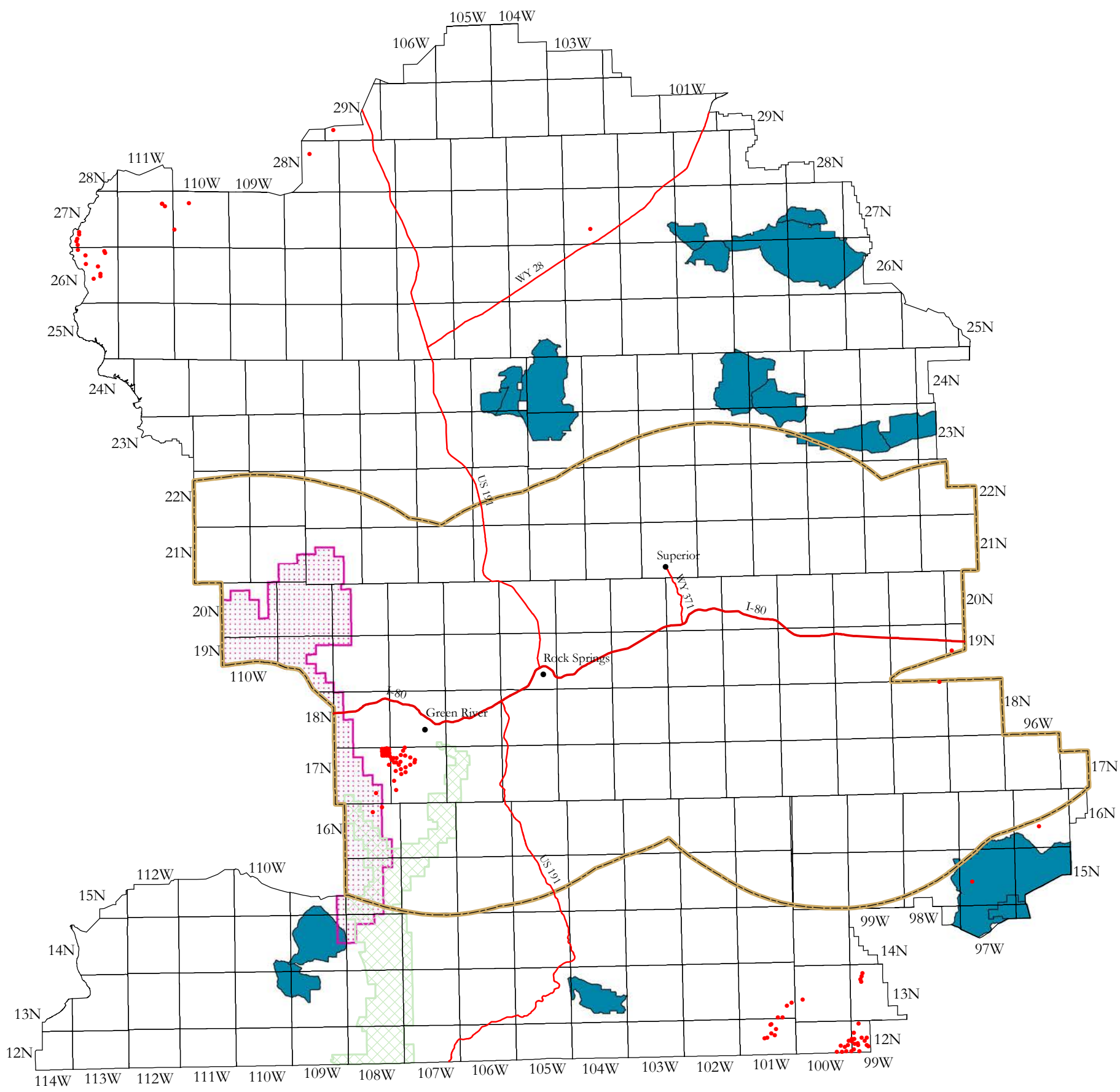
N

October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18g.
Locations of all wells completed inTertiary aged rocks within the Planning Area. Data from IHS Energy Group (2012).



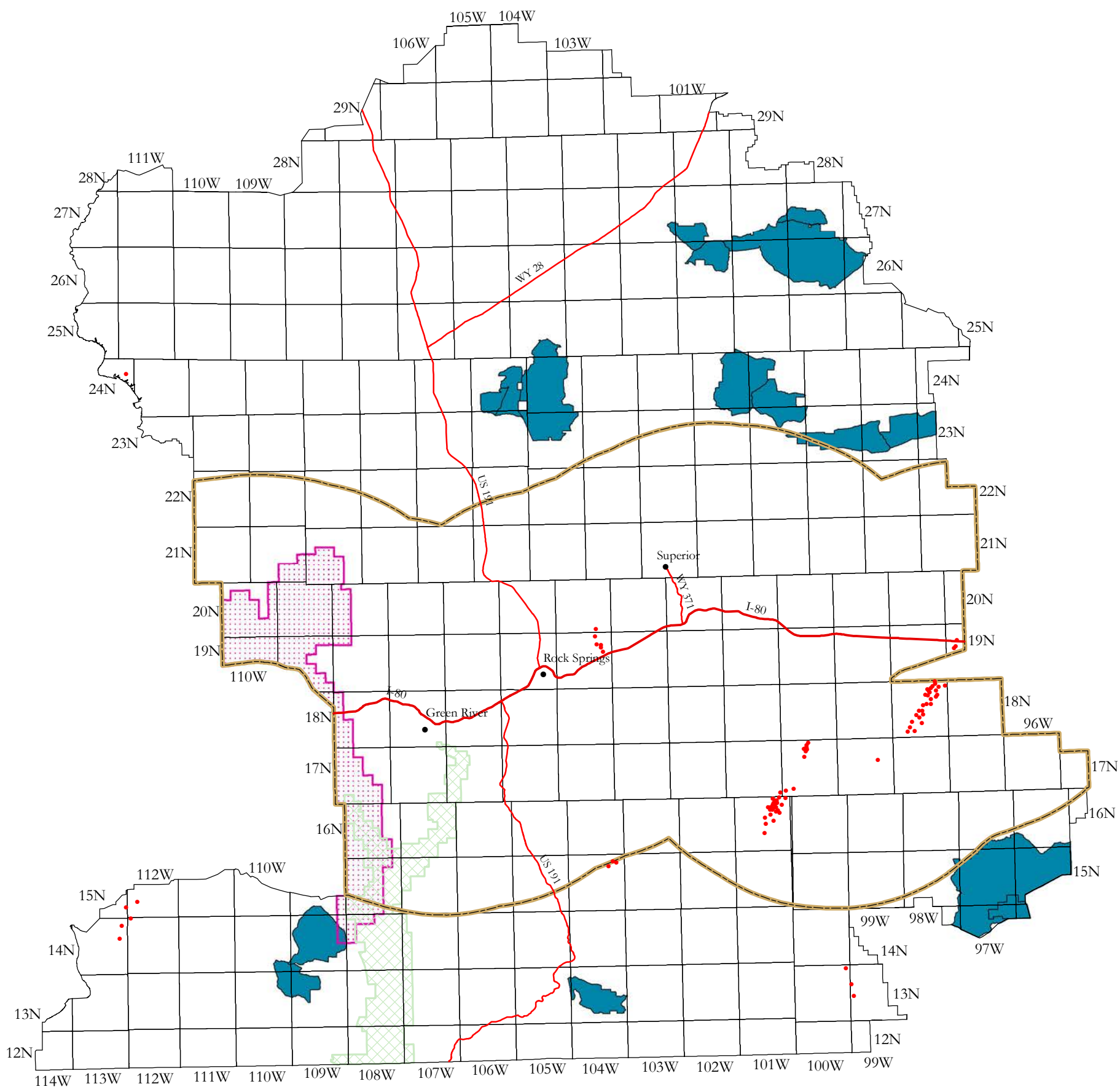
Wyoming State Office
Reservoir Management Group

October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 18h.
Locations of all wells completed in Nugget Sandstone and older rocks within the Planning Area. Data from IHS Energy Group (2012).



Wyoming State Office
Reservoir Management Group

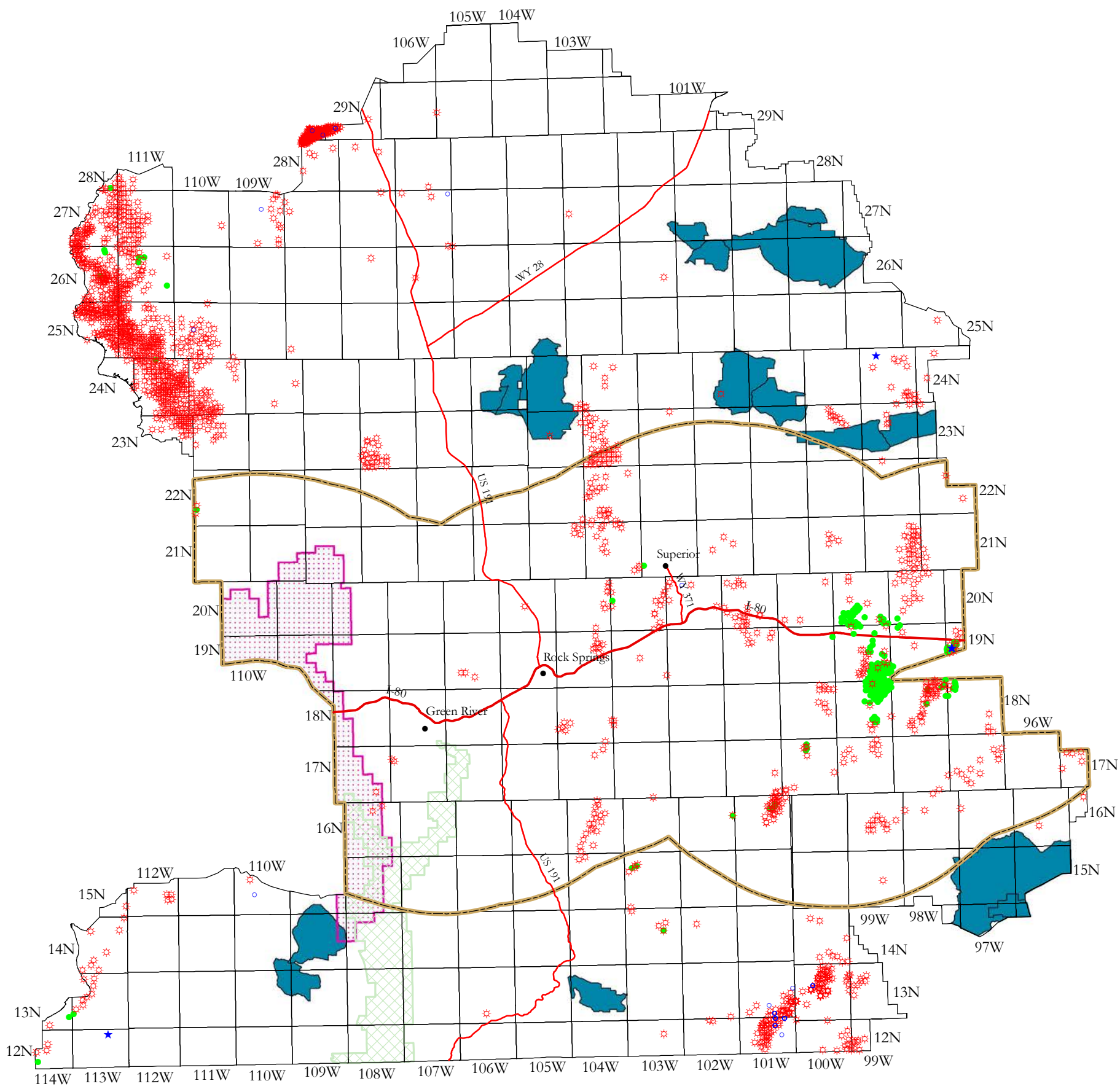
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 19a.

Rock Springs Planning Area locations of all conventional oil and gas wells that have been spudded and not completed and those still capable of producing oil and gas. Data from Wyoming Oil and Gas Conservation Commission (2012).



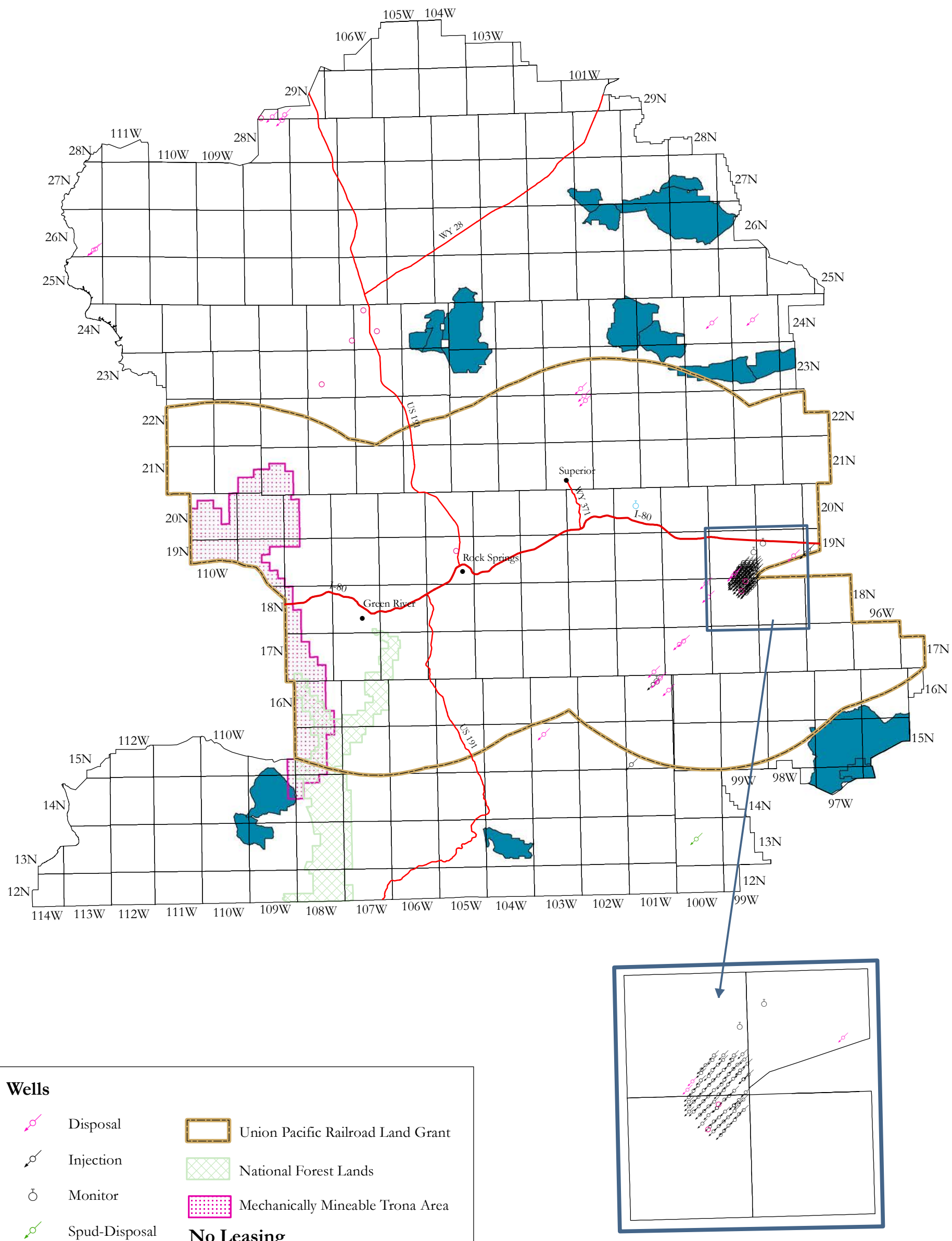
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure19b.

Rock Springs Planning Area locations of all conventional wells being used for enhanced oil recovery purposes (water injection, polymer enhanced flooding, surfactant flooding, and carbon dioxide injection), for disposal (acid gas and water disposal), monitoring, and as water source wells. Data from Wyoming Oil and Gas Conservation Commission (2012).



Wyoming State Office

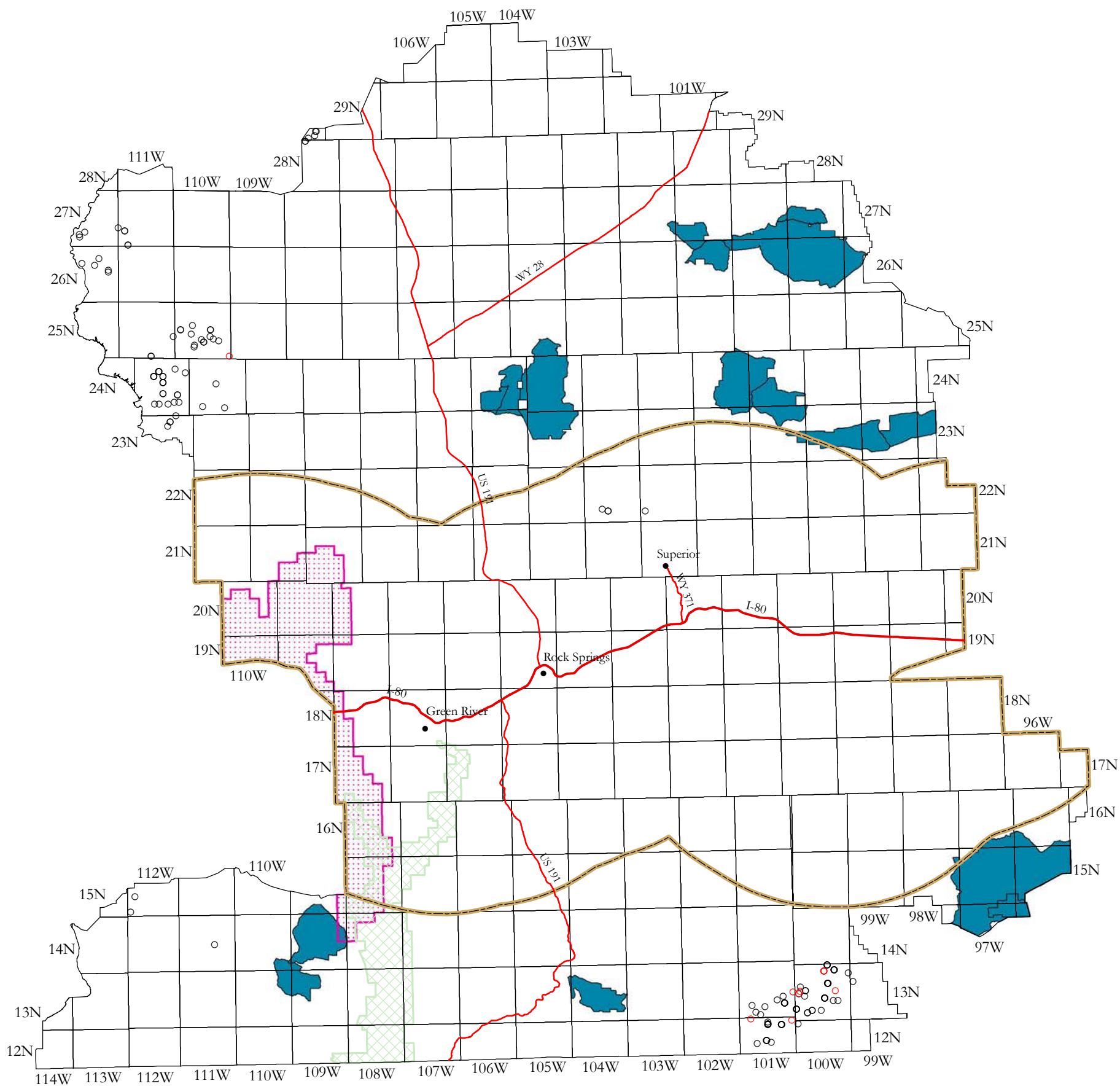
Reservoir Management Group

October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 19c.
Rock Springs Planning Area locations of all conventional well drilling permits (approved and waiting on approval). Data from Wyoming Oil and Gas Conservation Commission (2012).



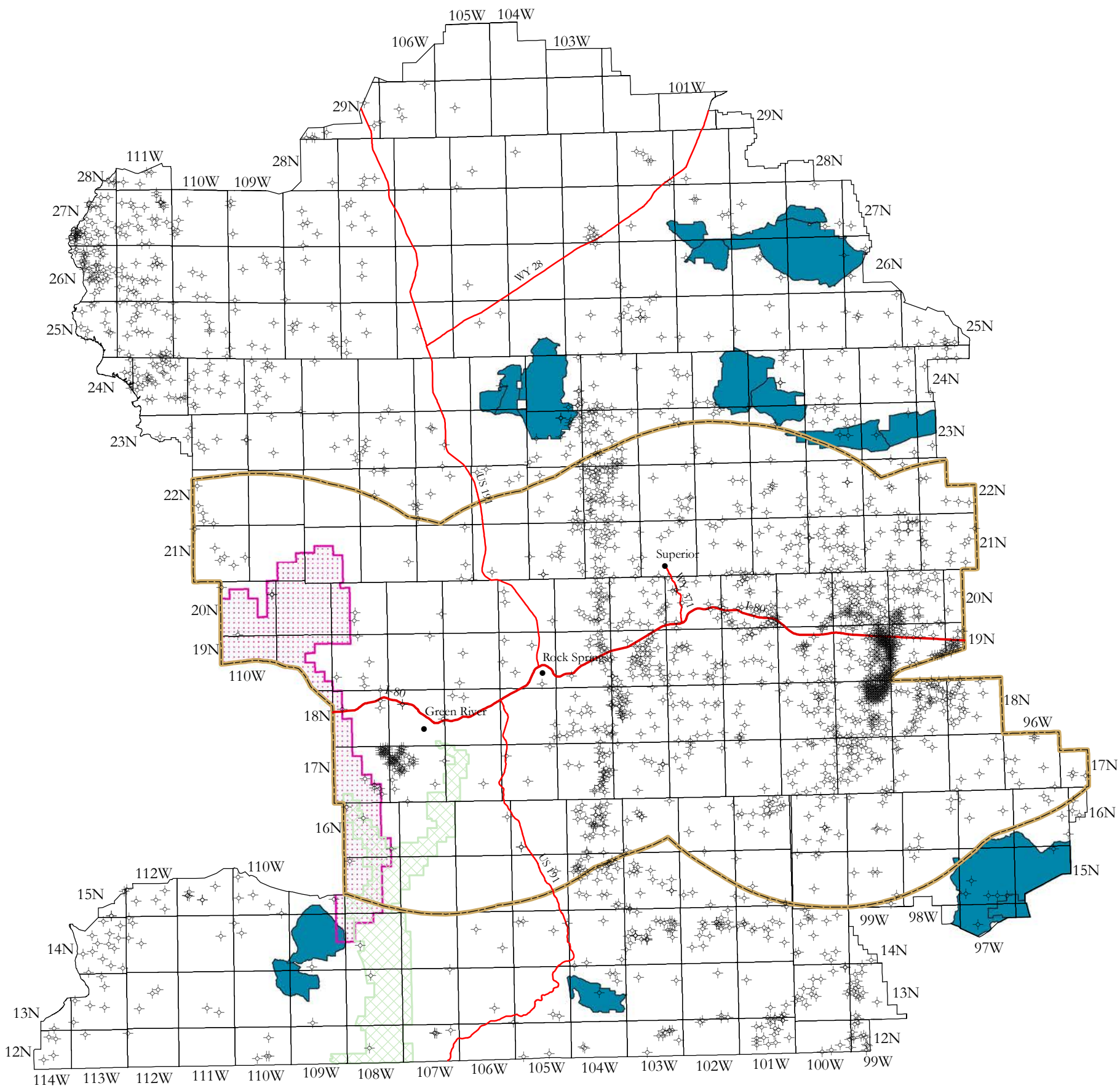
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 19d.

Rock Springs Planning Area locations of all abandoned conventional wells. Data from Wyoming Oil and Gas Conservation Commission (2012).



Wyoming State Office

Reservoir Management Group

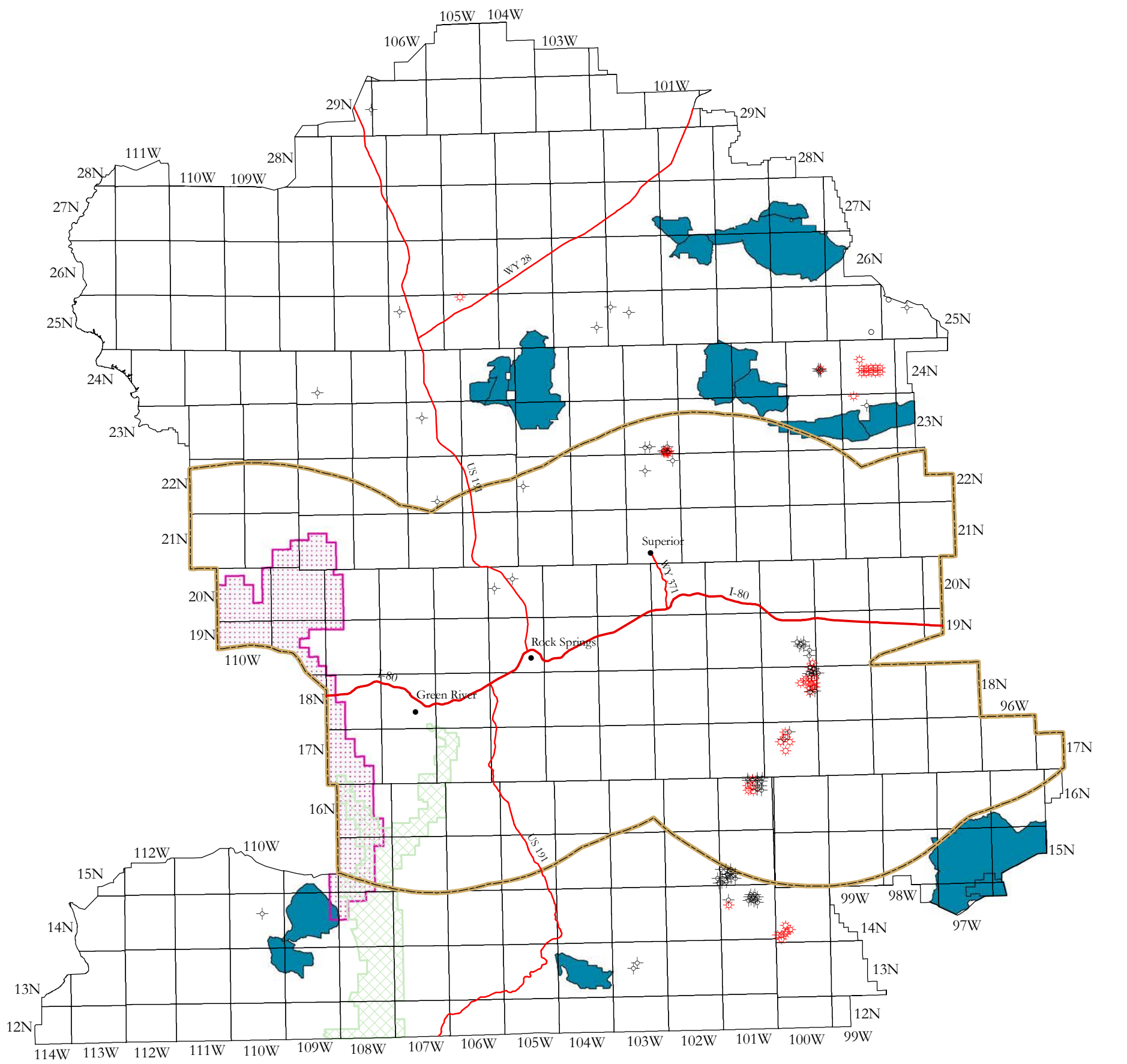
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure20.

Rock Springs Planning Area locations and status of all coalbed natural gas related wells and permits. Data from Wyoming Oil and Gas Conservation Commission (2012).

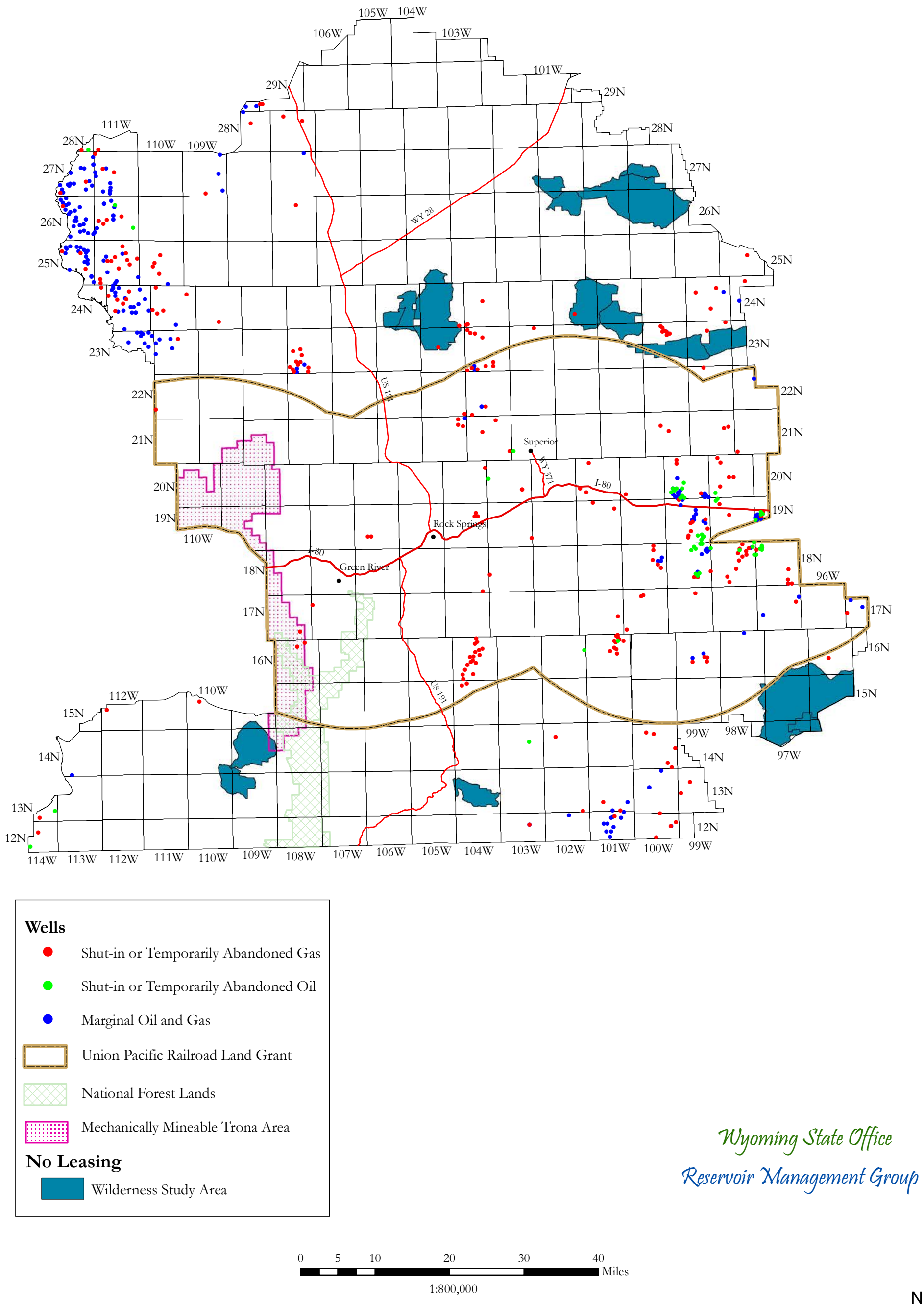


October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 21.
Location of marginal oil and gas wells and shut-in or temporarily abandoned oil and gas wells within the Rock Springs Planning Area. Data from IHS Energy (2012) and Wyoming Oil and Gas Conservation Commission (2012).



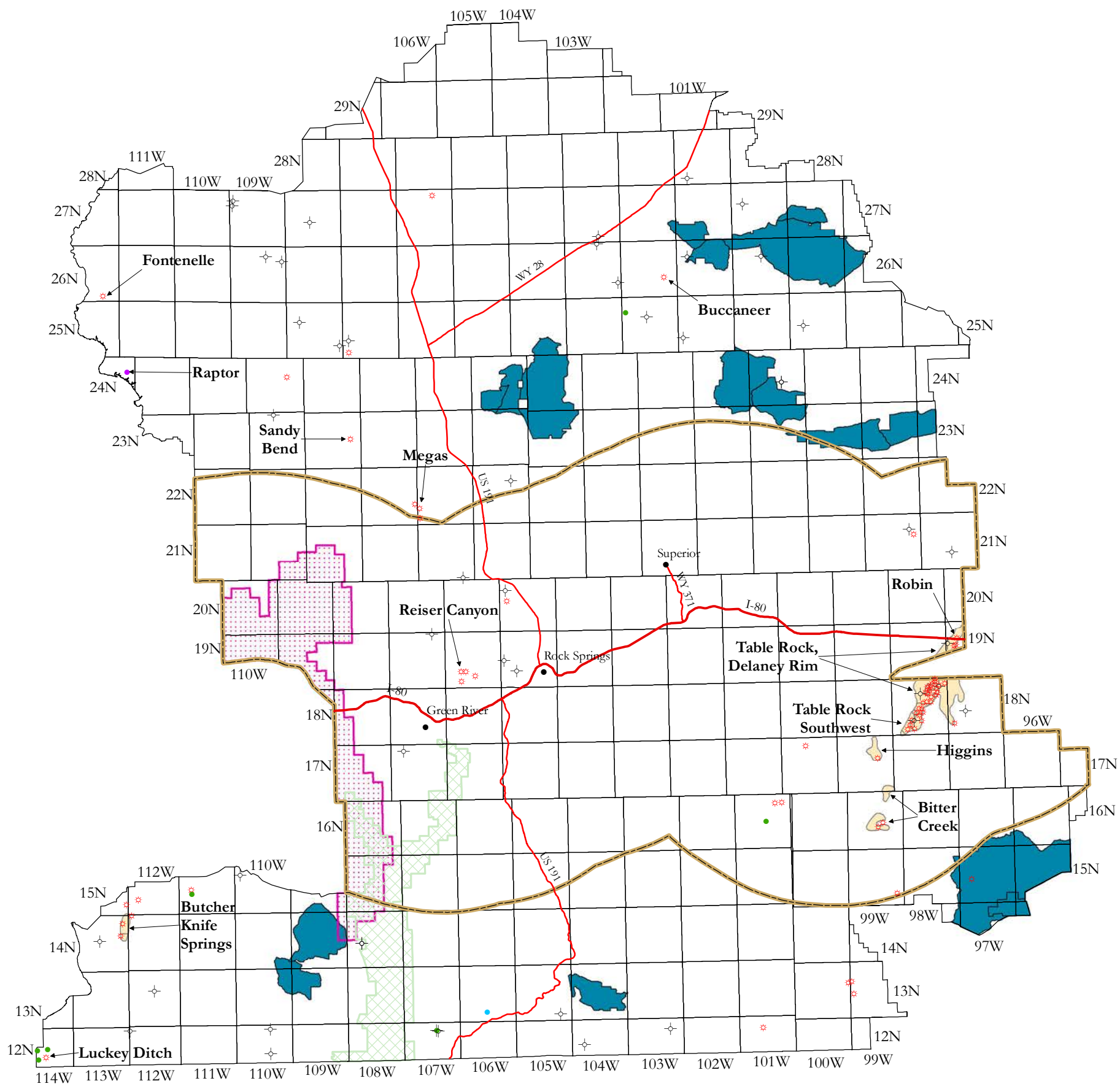
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 22a.

All conventional wells in the Rock Springs Planning Area with a true vertical depth greater than 15,000 feet, initial well completion status, and fields productive at greater than 15,000 feet. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Oil and Gas Fields

Wells

Abandoned

Gas

Carbon Dioxide

Injection

Oil

Permit

Service/Observation/Pilot

Spudded

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

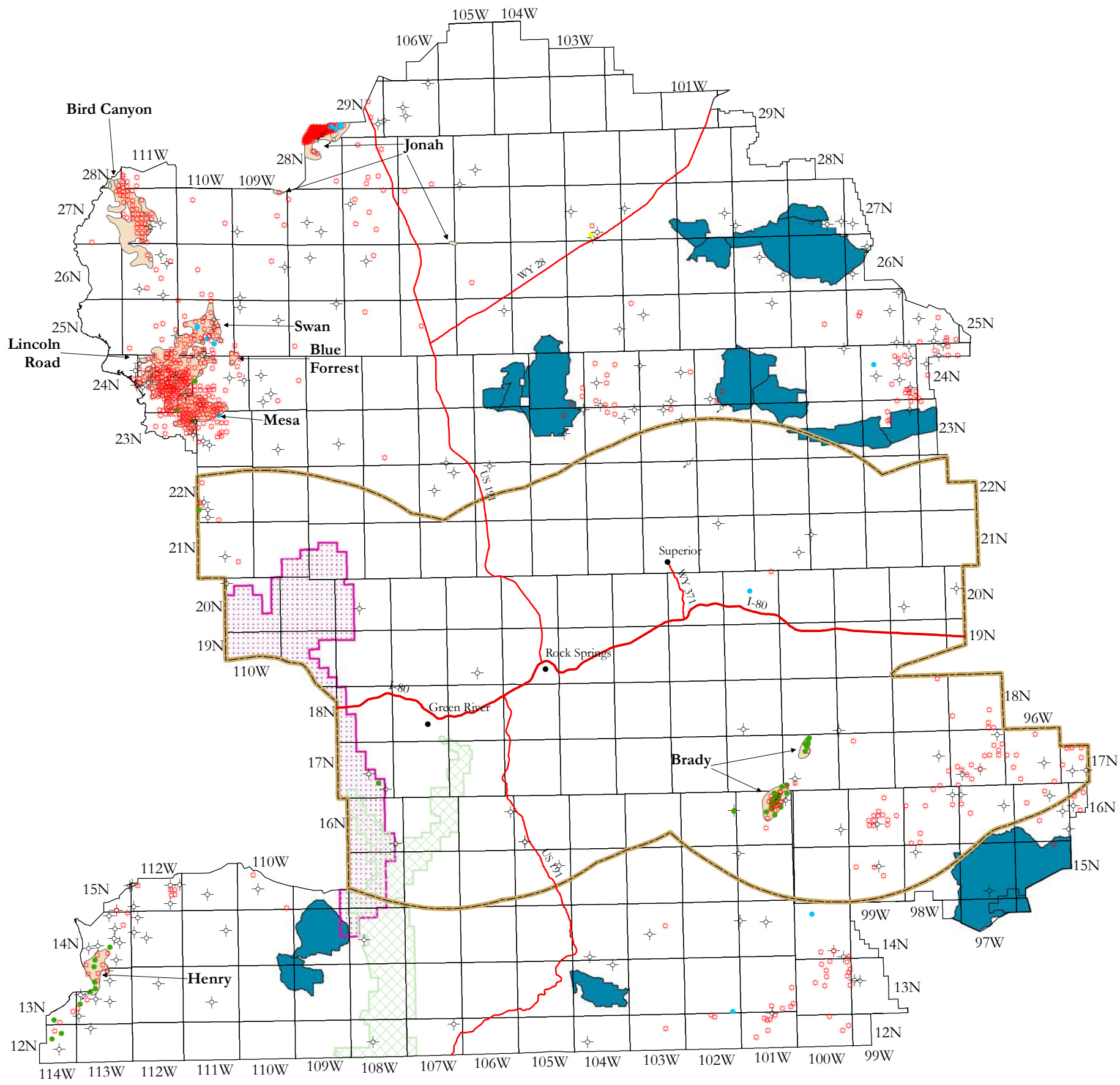
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 22b.

All conventional wells in the Rock Springs Planning Area with a true vertical depth of 10,000 to15,000 feet and their initial completion status. Data from IHS Energy Group (2012).



Union Pacific Railroad Land Grant

National Forest Lands

Mechanically Mineable Trona Area

No Leasing

Wilderness Study Area

Oil and Gas Fields

Wells

Abandoned

Gas

Carbon Dioxide

Injection

Oil

Permit

Service/Observation/Pilot

Spudded

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

N

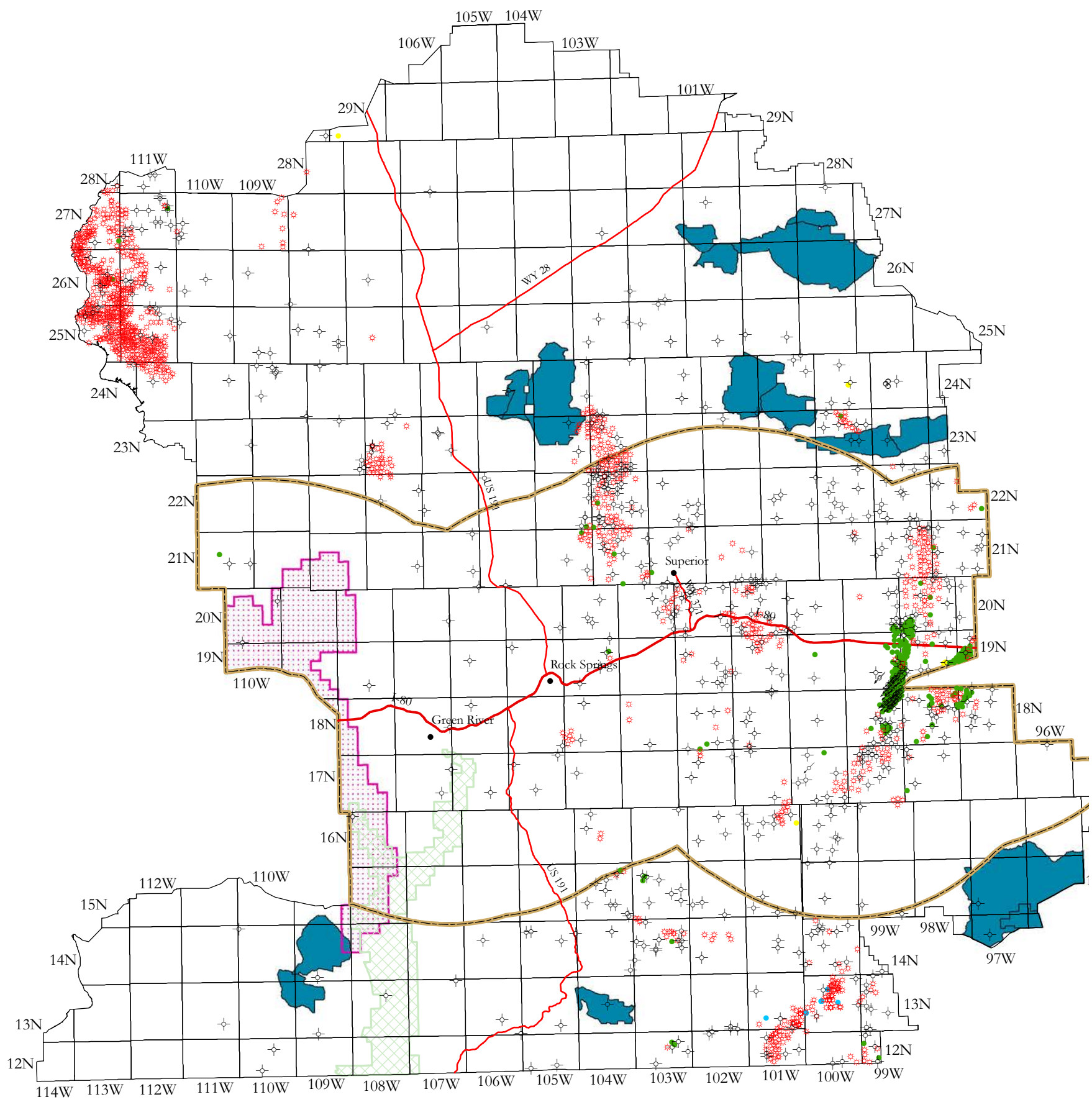
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 22c.

All conventional wells in the Rock Springs Planning Area with a true vertical depth of 5,000 to9,999 feet and their initial completion status. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

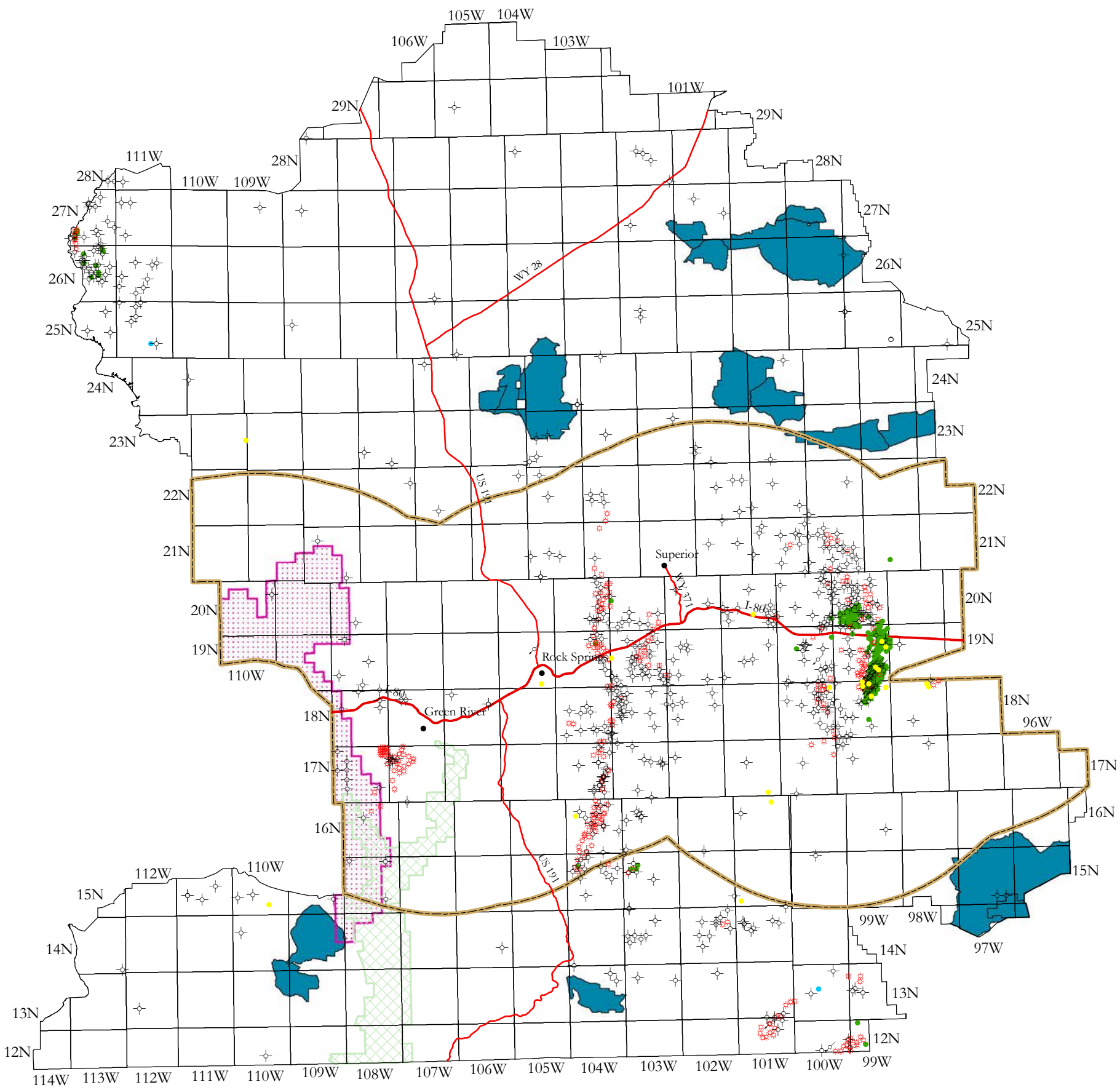
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 22d.

All conventional wells in the Rock Springs Planning Area with a true vertical depth of less than 5,000 feet and their initial completion status. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

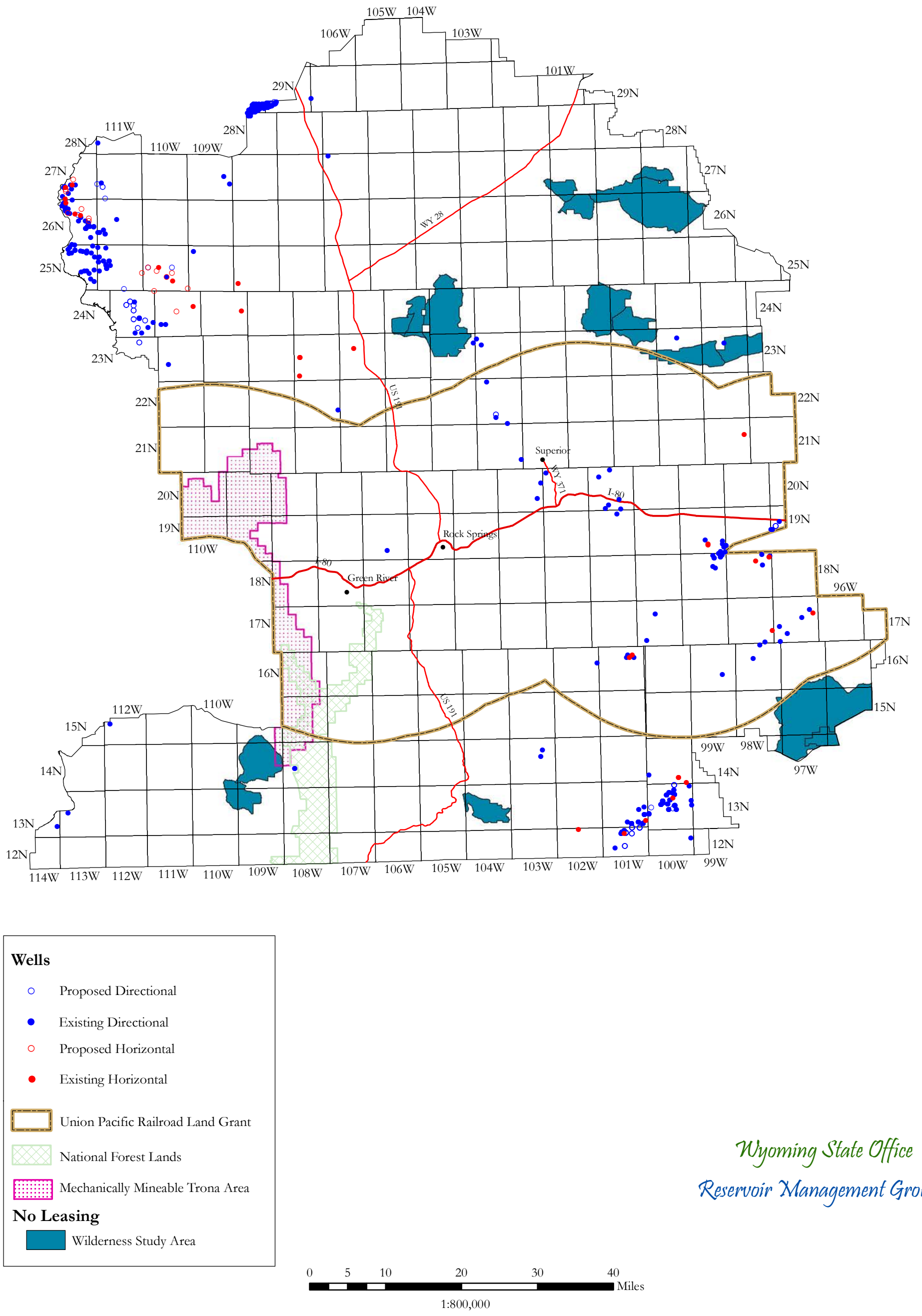
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 23.

Existing and proposed directional and horizontal borehole locations within the Rock Springs Planning Area. Data from IHS Energy Group (2012).



Wyoming State Office

Reservoir Management Group

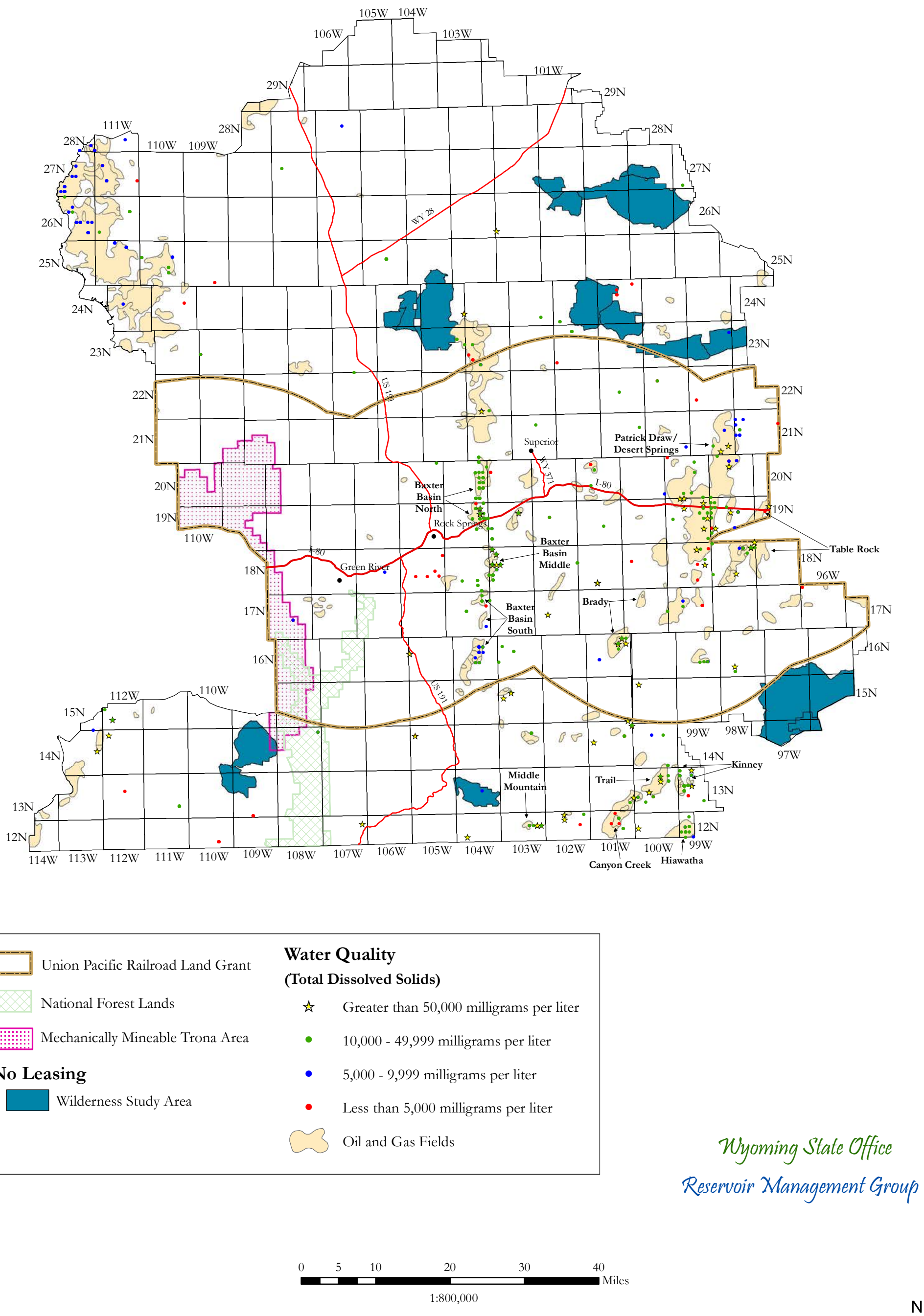
June, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 24.

Geographic distribution of water quality samples across the Rock Springs Planning Area and distribution of sample salinity. Data from U.S. Geological Survey (2008).



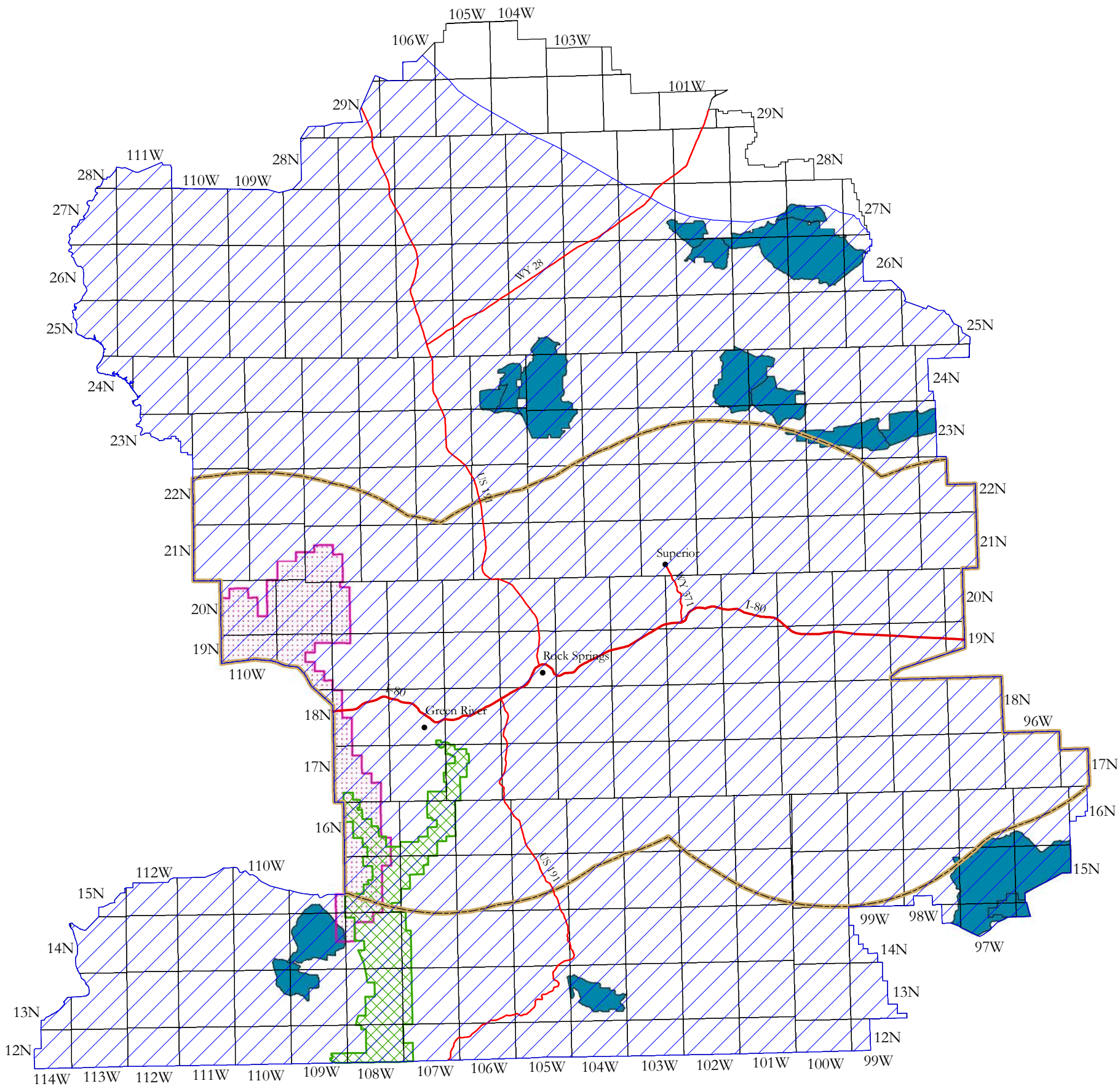
October, 2012

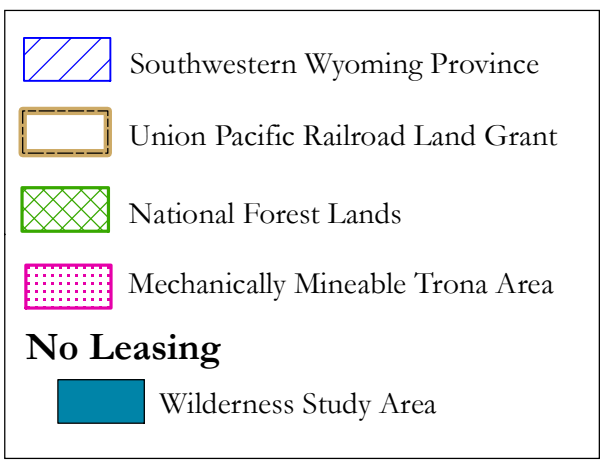
Dean Stilwell, Geologist

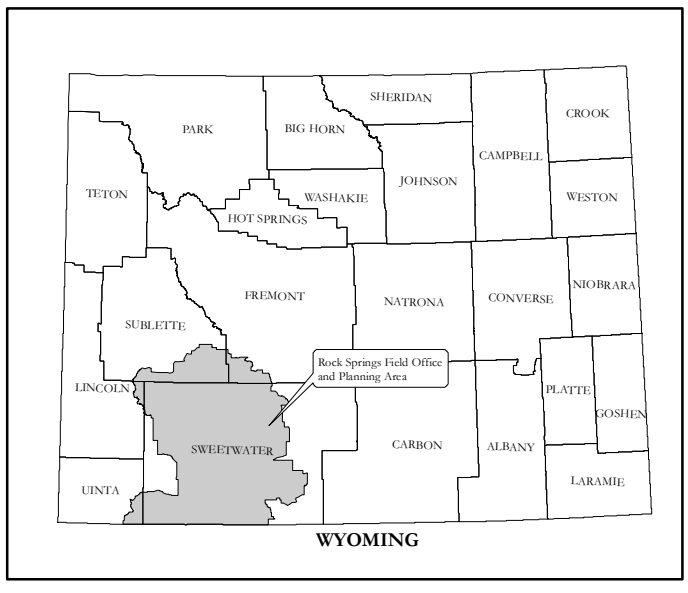
No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 25.

Location of the 2002 Southwestern Wyoming Province boundary within the Rock Springs Planning Area (U.S. Geological Survey, 2002).







Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

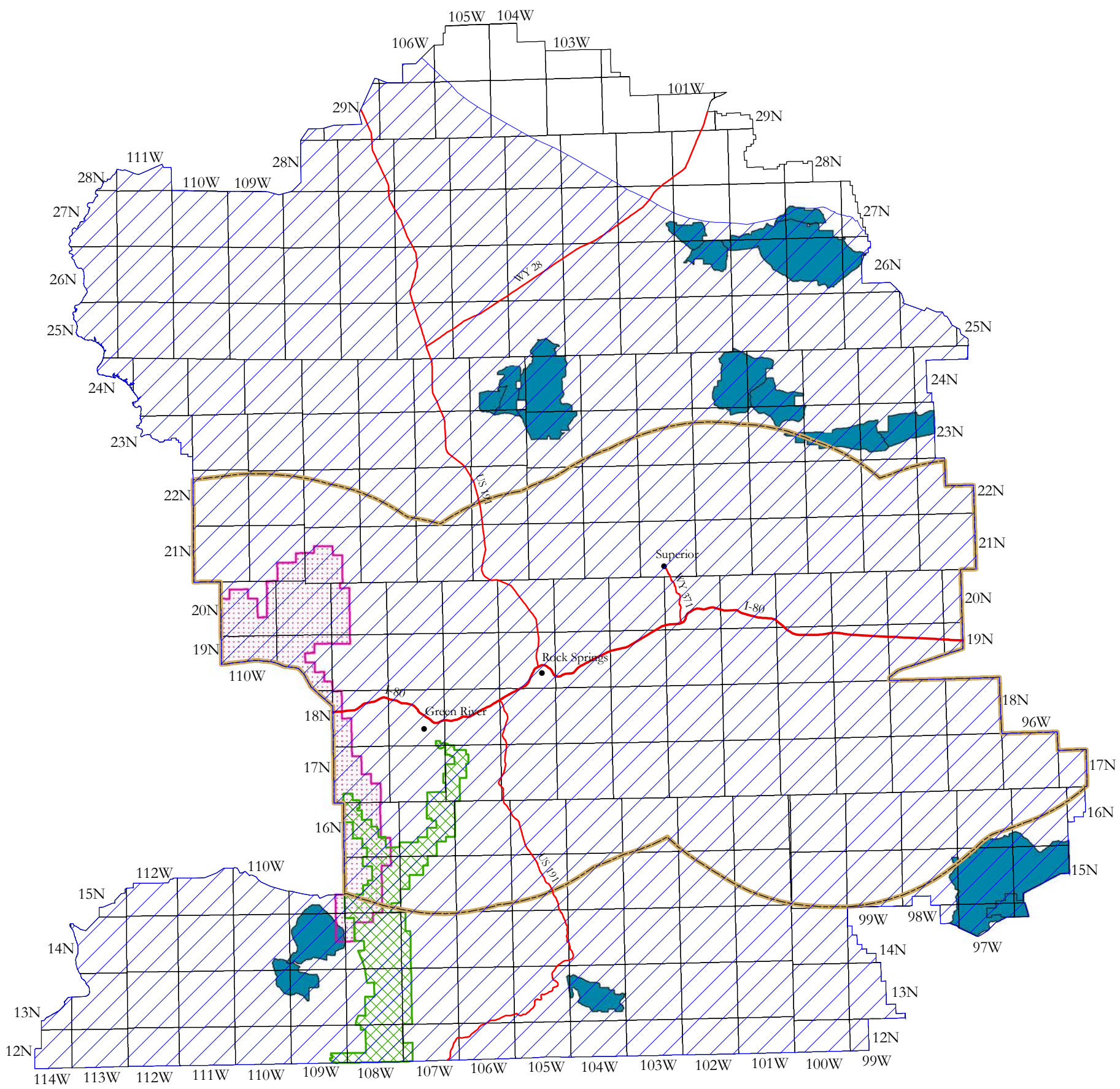
N

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 26.
Location of the 2002 Southwestern Wyoming Province Phosphoria Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Phosphoria Total Petroleum System Assessment Unit

- Sub-Cretaceous Conventional Oil and Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

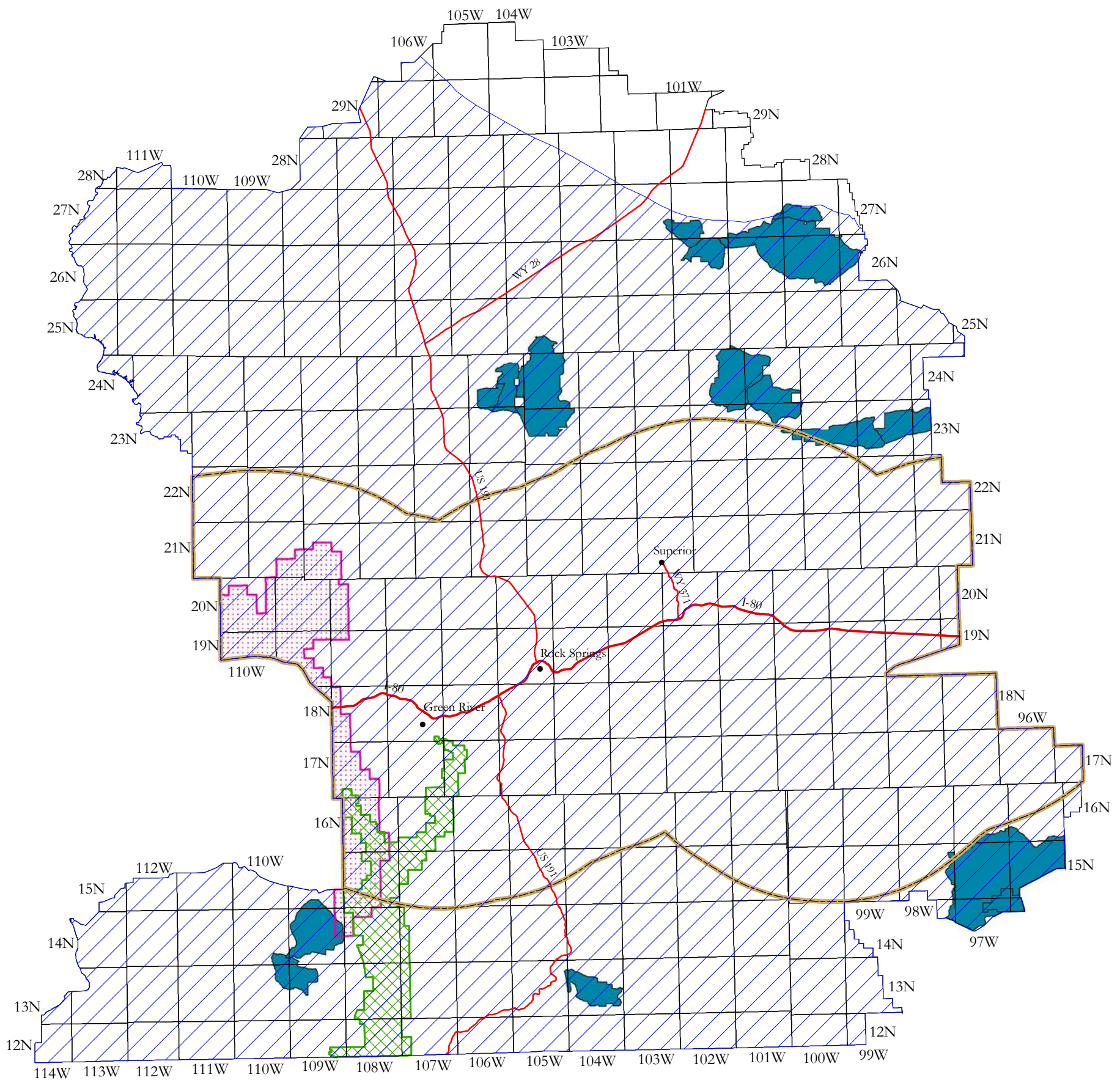
June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

N

Figure 27.
Location of the 2002 Southwestern Wyoming Province Mowry Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



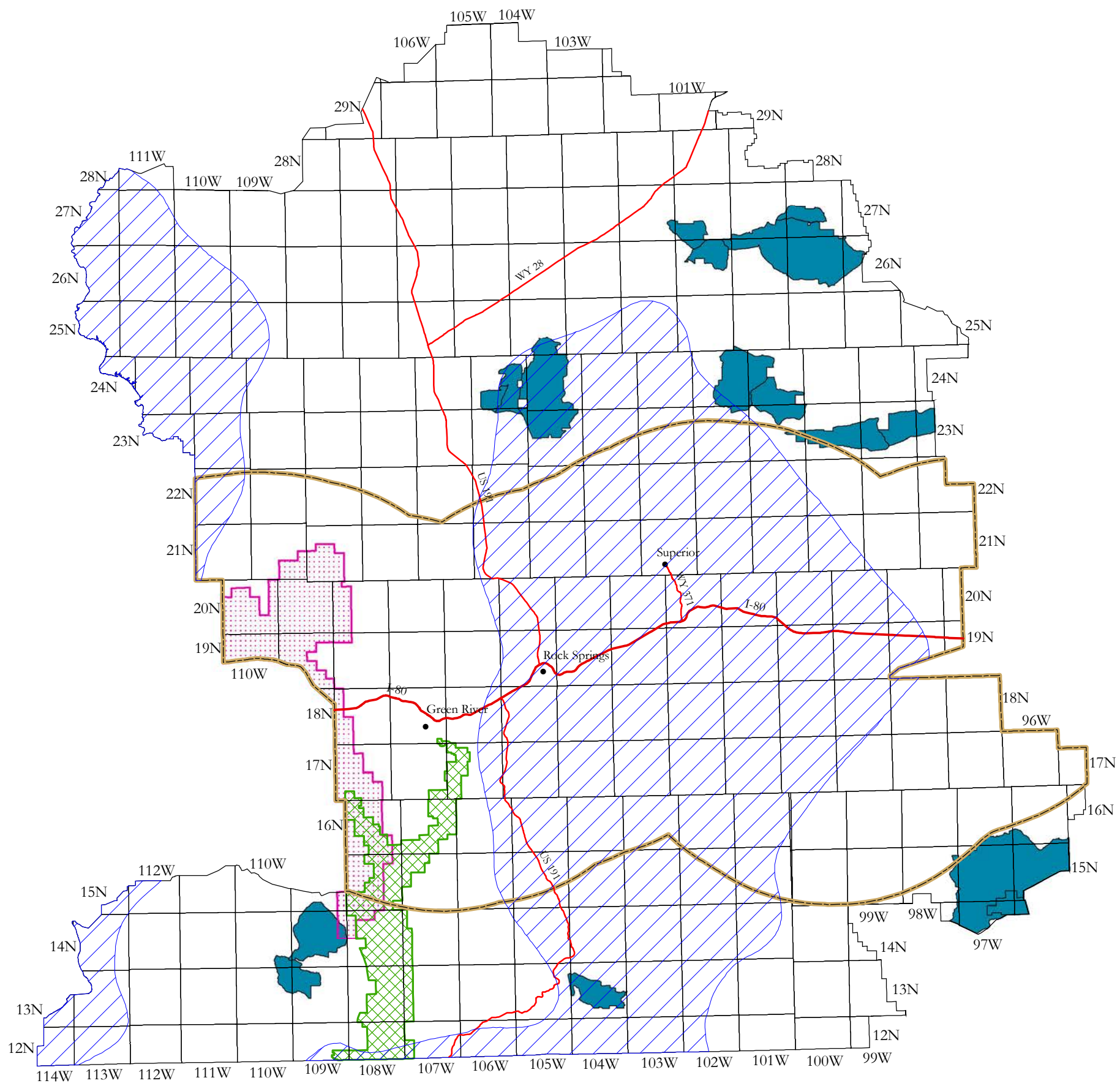
Wyoming State Office
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 28.
Location of the 2002 Southwestern Wyoming Province Hilliard-Baxter-Mancos Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Hilliard-Baxter-Mancos Total Petroleum System Assessment Unit

- Hilliard-Baxter-Mancos Conventional Oil and Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

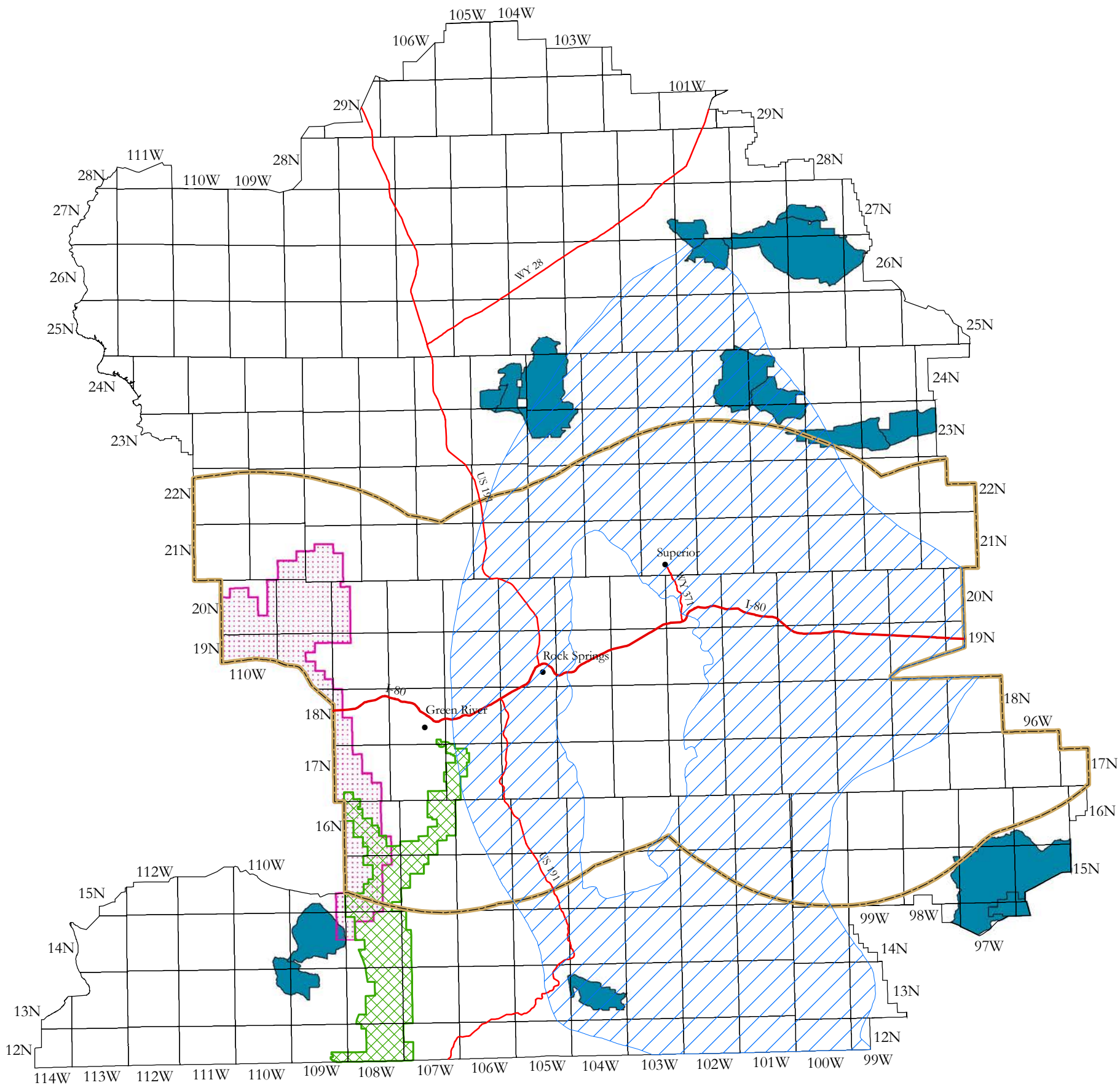
N

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 29.
Location of the 2002 Southwestern Wyoming Province Mesaverde Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



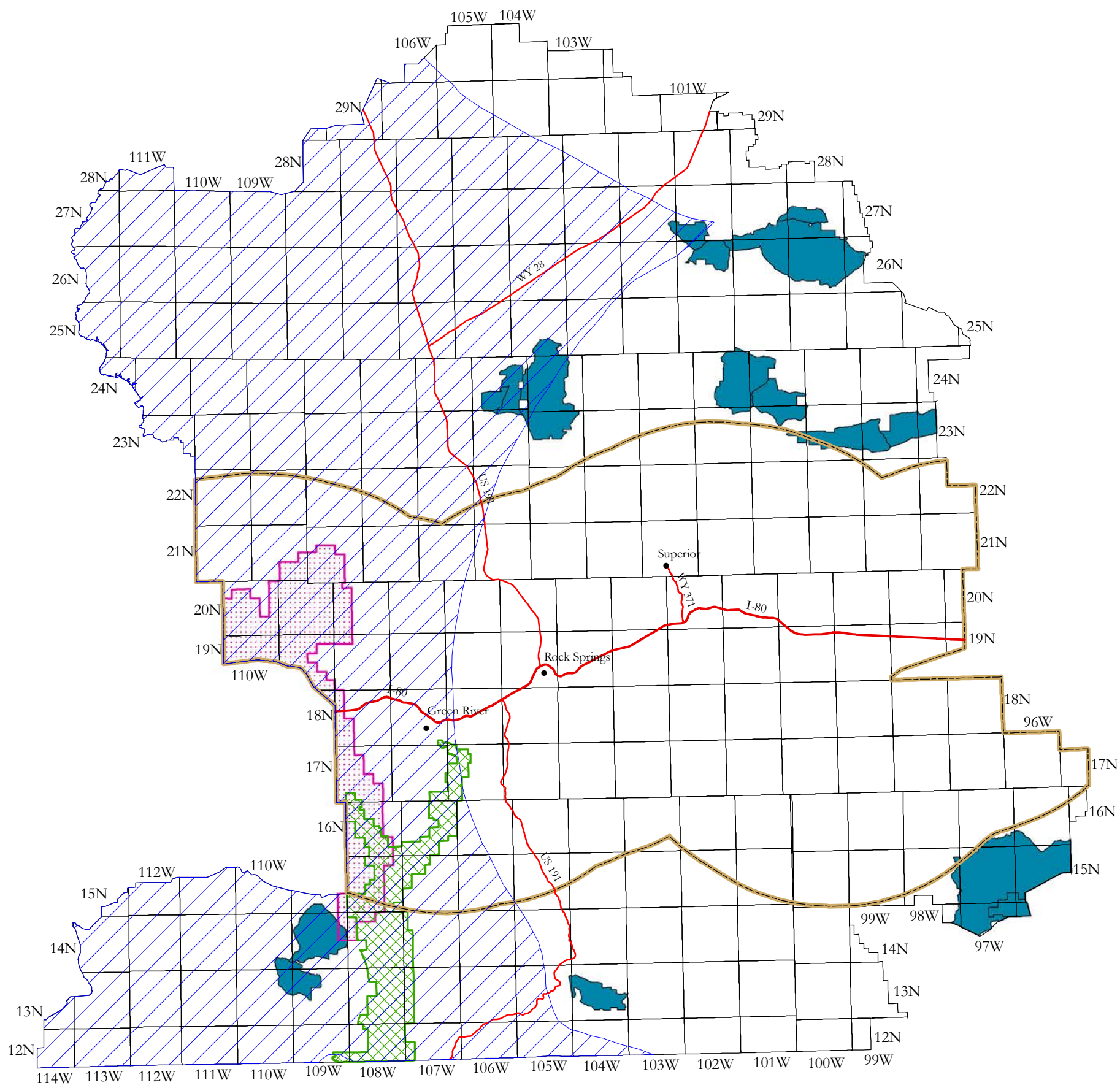
Wyoming State Office
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 30.
Location of the 2002 Southwestern Wyoming Province Mesaverde-Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Wyoming State Office
Reservoir Management Group

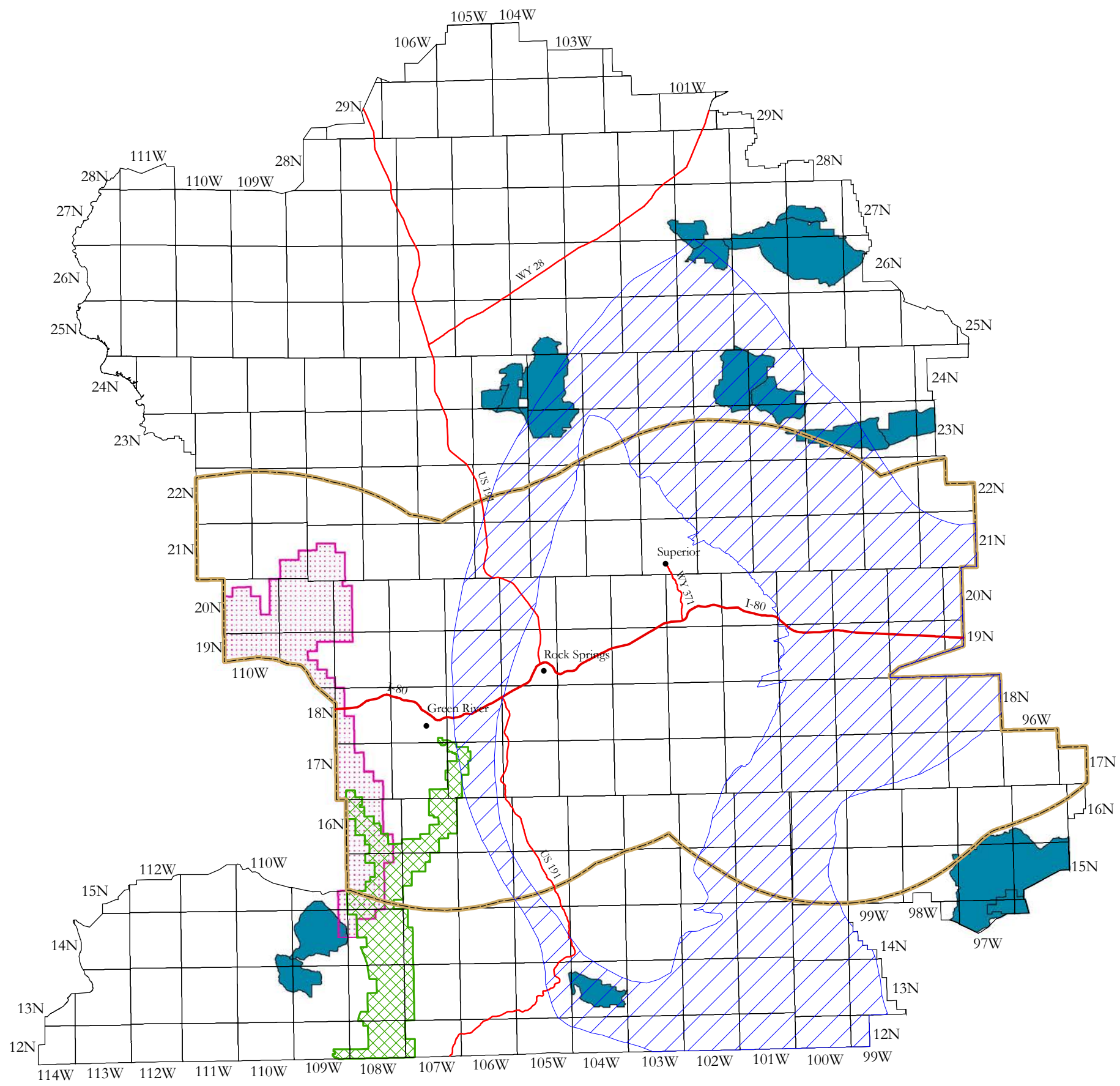
June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 31.

Location of the 2002 Southwestern Wyoming Province Lewis Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Wyoming State Office

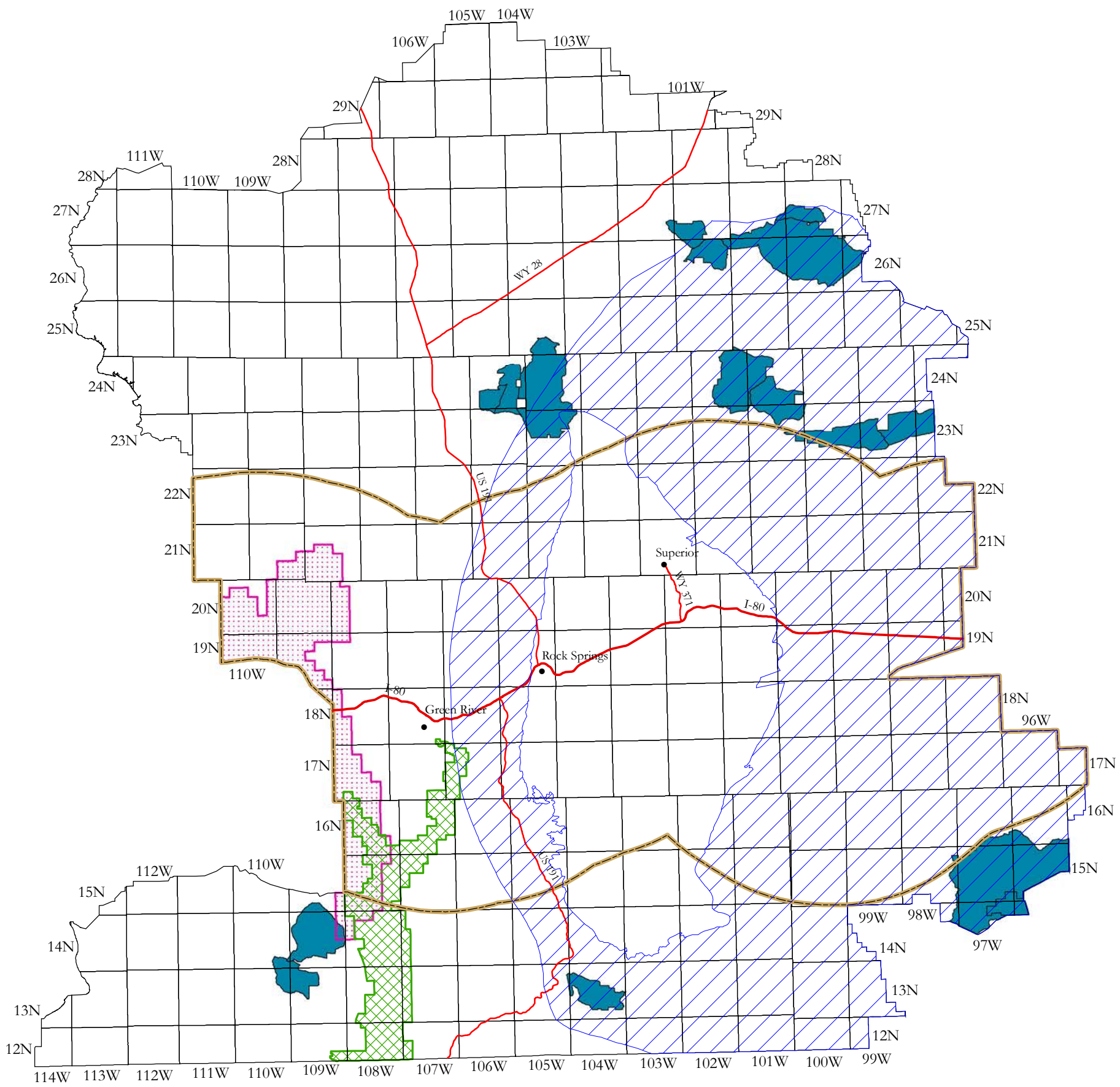
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 32.
Location of the 2002 Southwestern Wyoming Province Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).

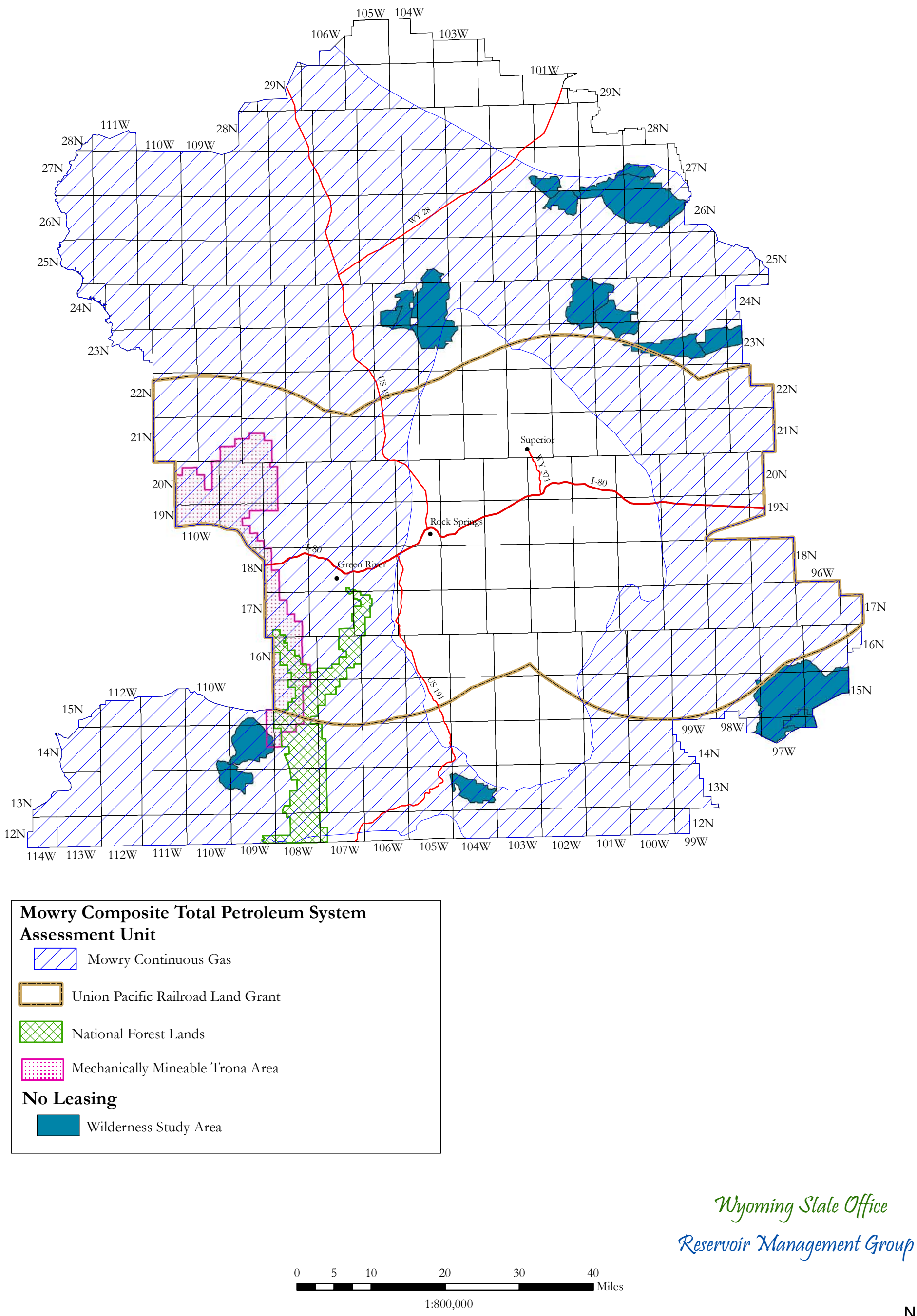


June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 33.
Location of the 2002 Southwestern Wyoming Province Mowry Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



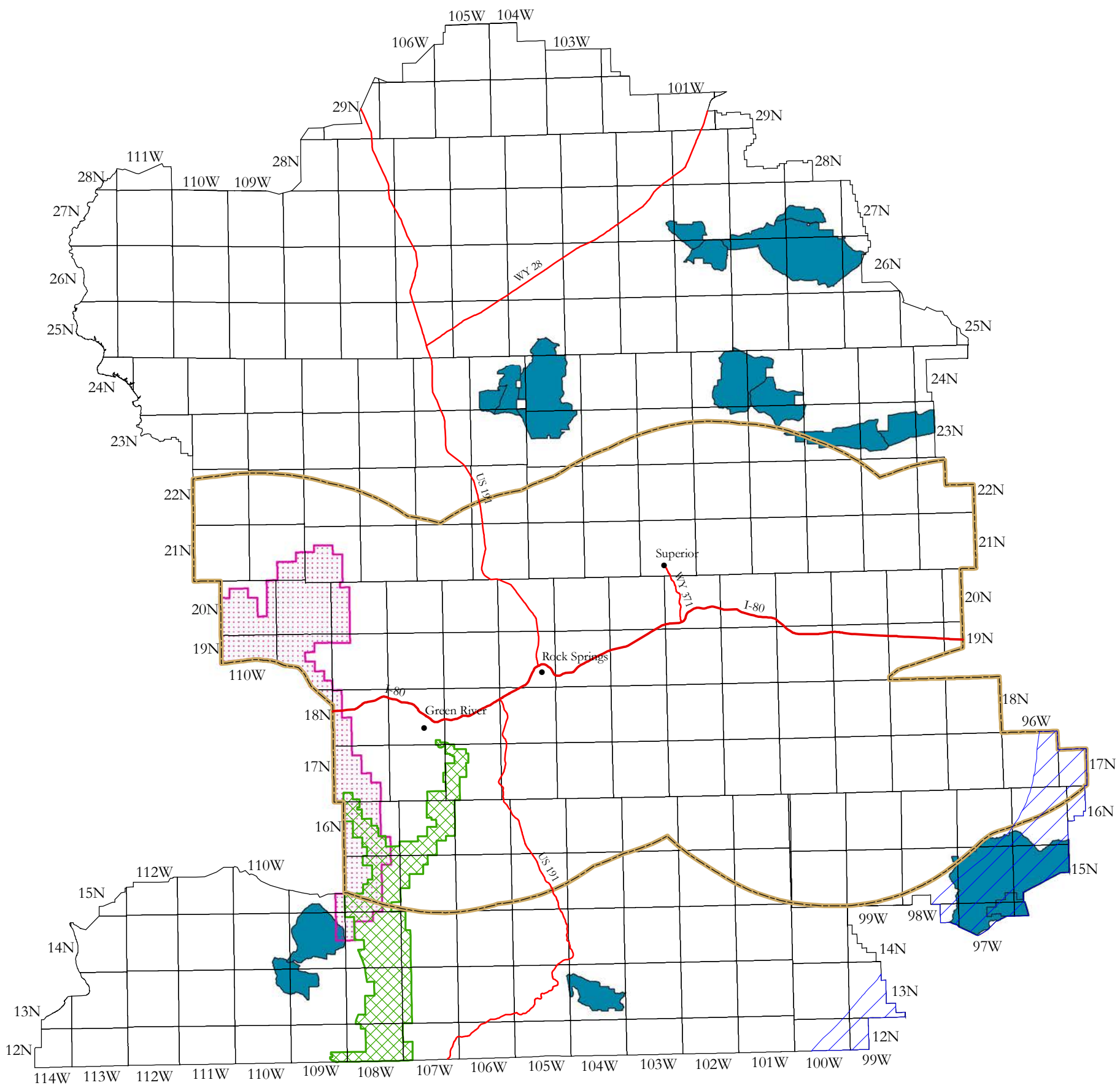
Wyoming State Office
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 34.
Location of the 2002 Southwestern Wyoming Province Niobrara Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



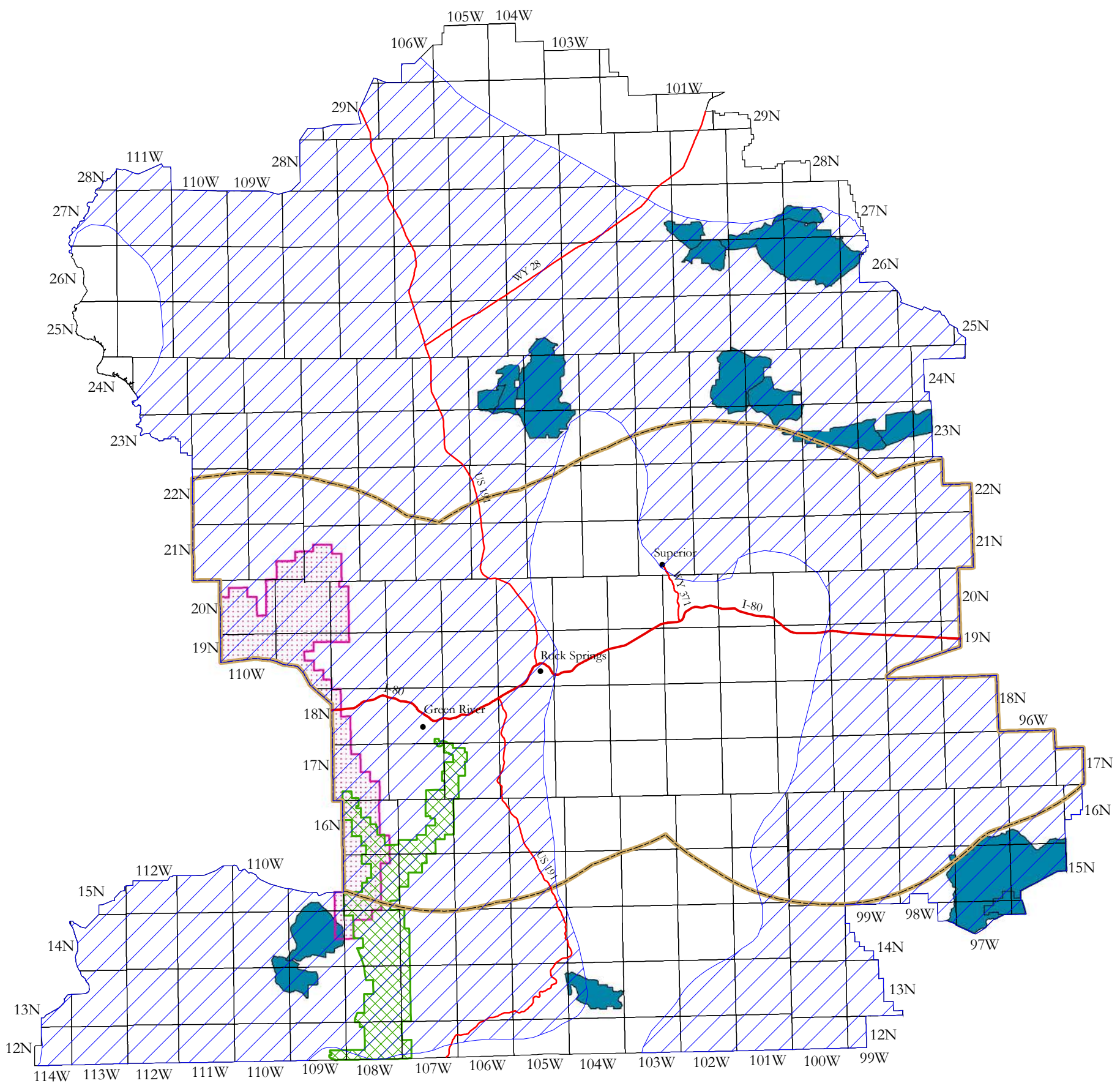
Wyoming State Office
Reservoir Management Group

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 35.
Location of the 2002 Southwestern Wyoming Province Hilliard-Baxter-Mancos Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).

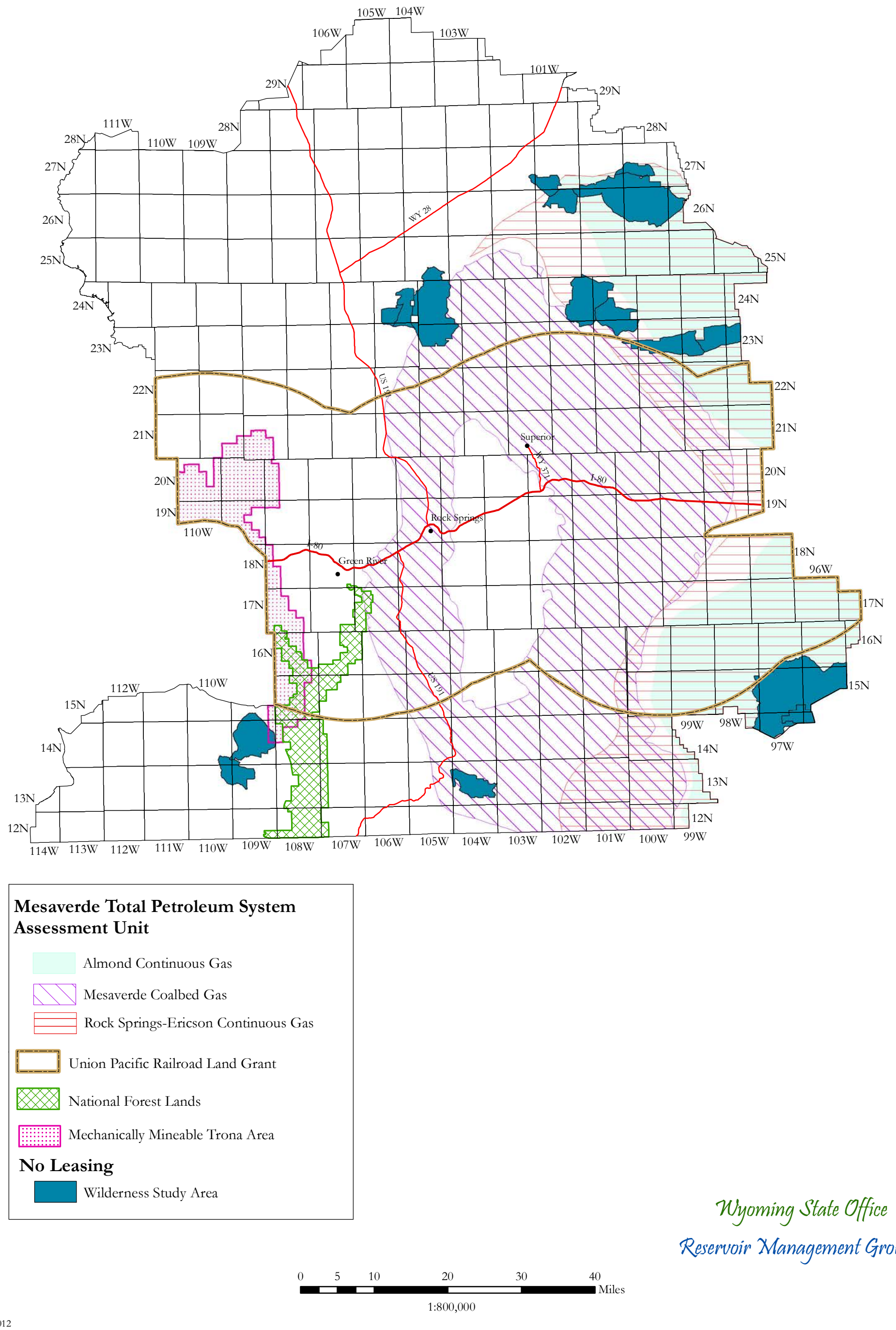


June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 36.
Location of the 2002 Southwestern Wyoming Province Mesaverde Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).

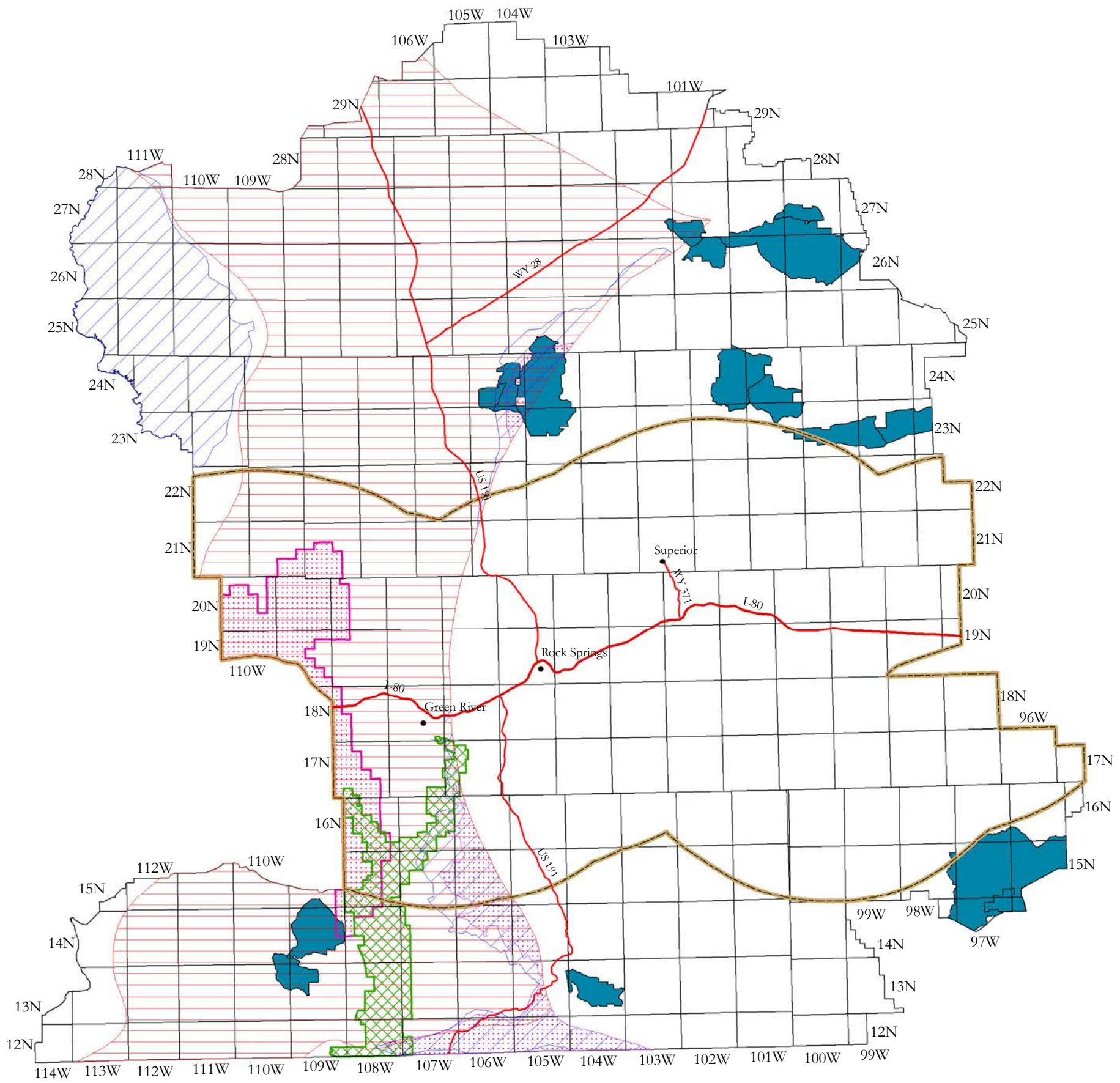


June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 37.
Location of the 2002 Southwestern Wyoming Province Mesaverde-Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Mesaverde-Lance-Fort Union Composite Total Petroleum System Assessment Unit

- Fort Union Coalbed Gas
- Mesaverde Coalbed Gas
- Mesaverde-Lance-Fort Union Continuous Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office
Reservoir Management Group

0 5 10 20 30 40 Miles
1:800,000

N

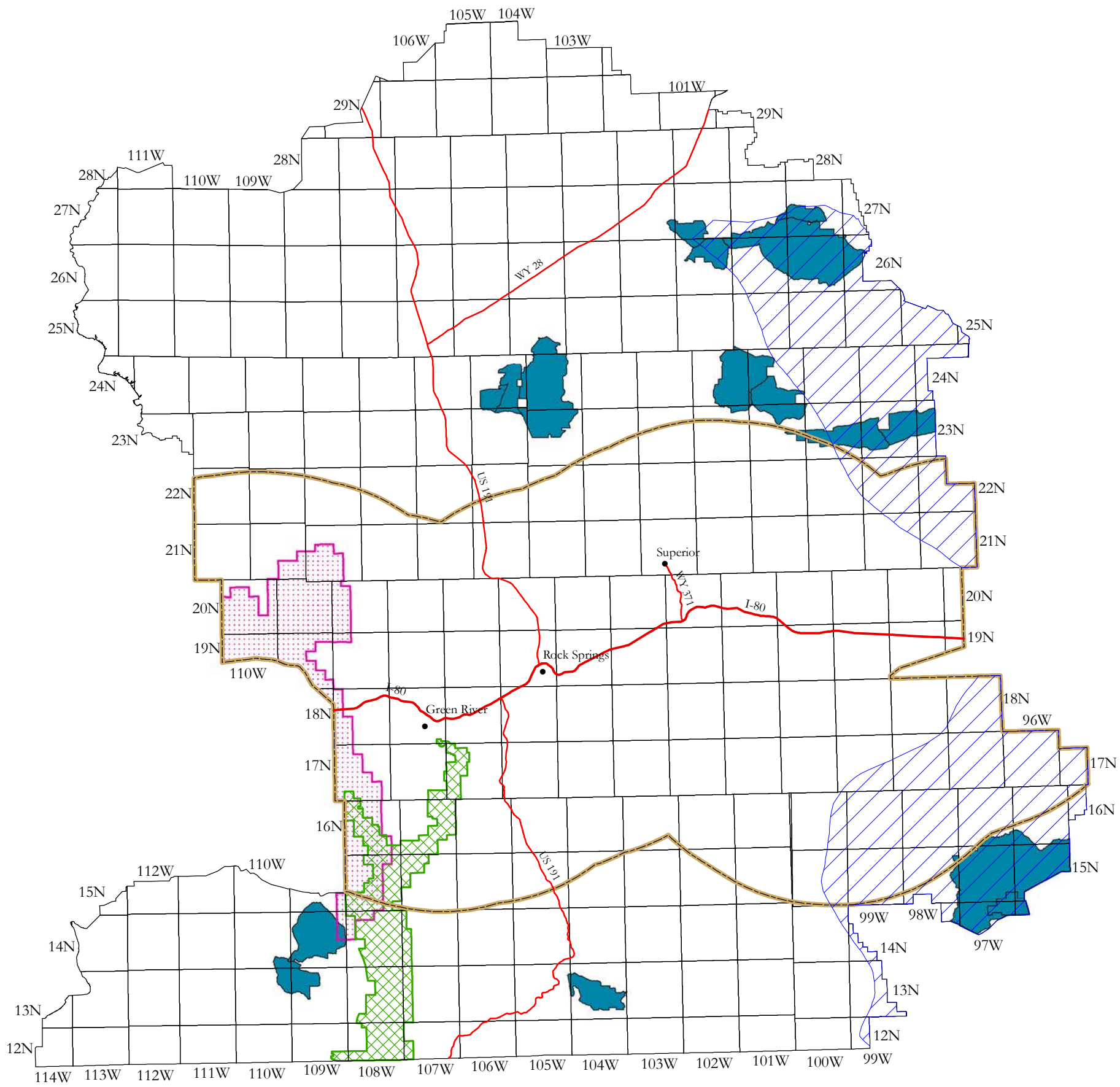
June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 38.

Location of the 2002 Southwestern Wyoming Province Lewis Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Lewis Total Petroleum System Assessment Unit

- Lewis Continuous Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

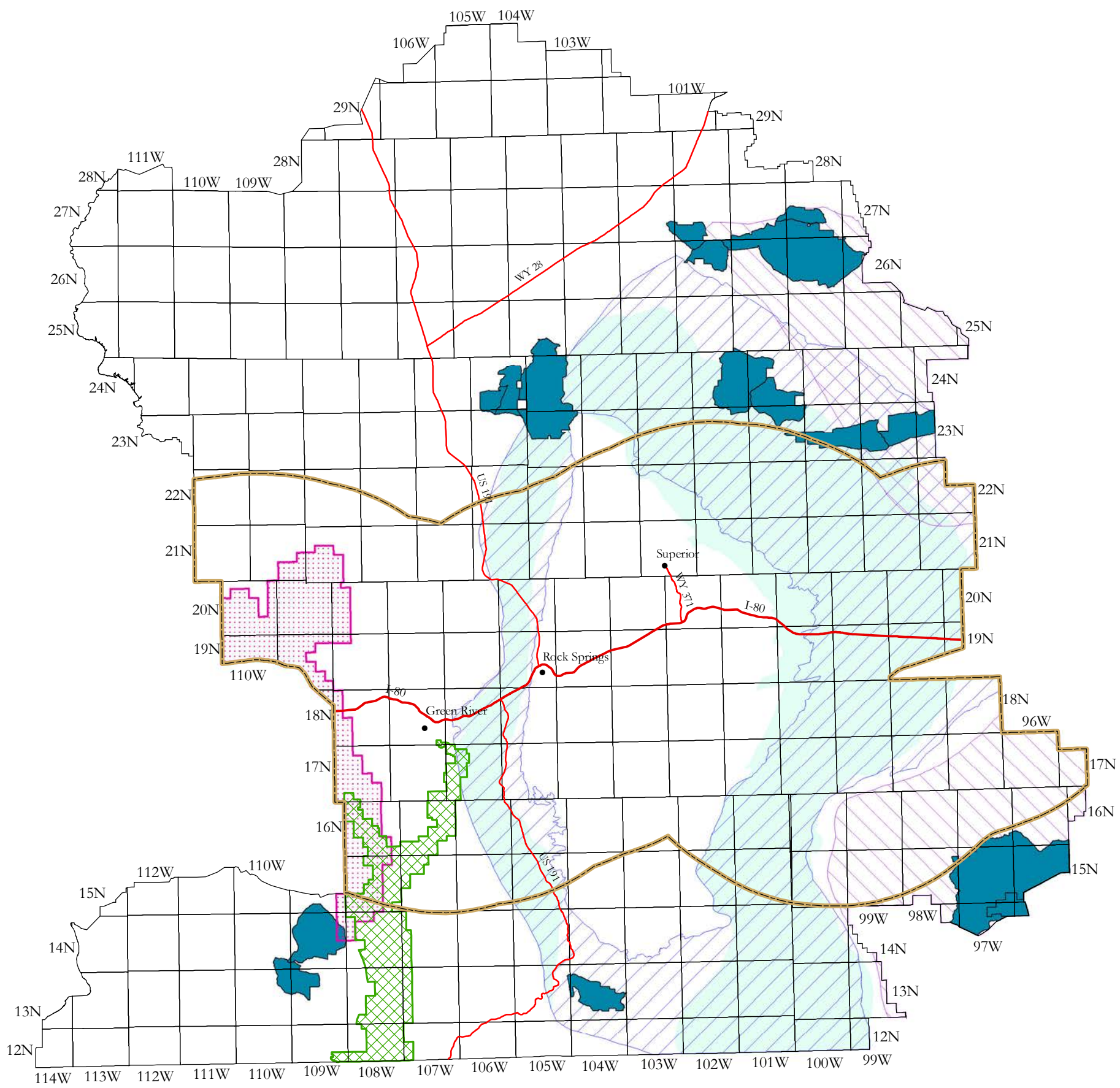
N

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 39.
Location of the 2002 Southwestern Wyoming Province Lance-Fort Union Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Lance-Fort Union Composite Total Petroleum System Assessment Units

- Fort Union Coalbed Gas
- Lance Coalbed Gas
- Lance-Fort Union Continuous Gas
- Union Pacific Railroad Land Grant
- National Forest Lands
- Mechanically Mineable Trona Area

No Leasing

- Wilderness Study Area

Wyoming State Office

Reservoir Management Group

0 5 10 20 30 40 Miles

1:800,000

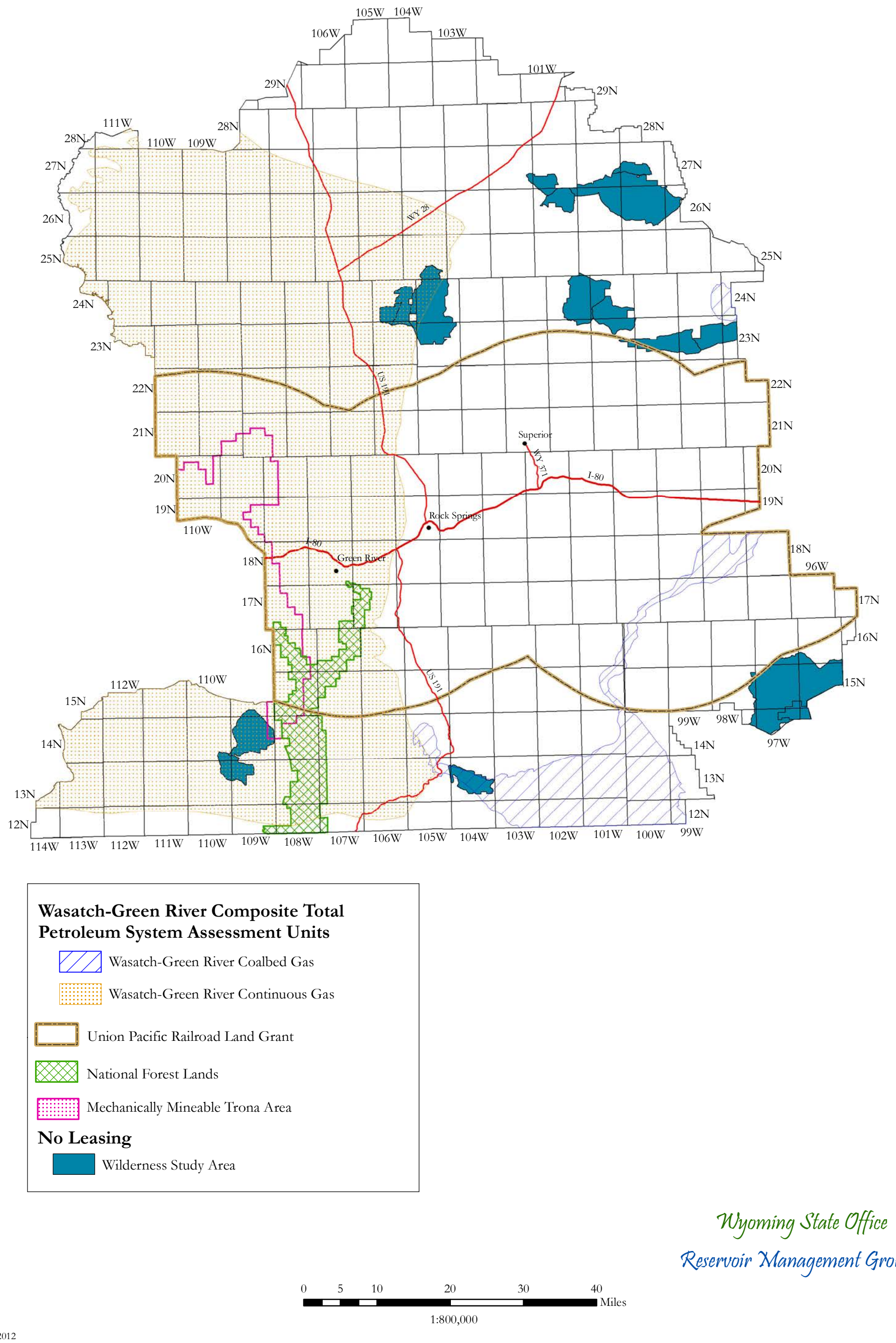
N

June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 40.
Location of the 2002 Southwestern Wyoming Province Wasatch-Green River Composite Total Petroleum System within the Rock Springs Planning Area (U.S. Geological Survey, 2002).



Wyoming State Office
Reservoir Management Group

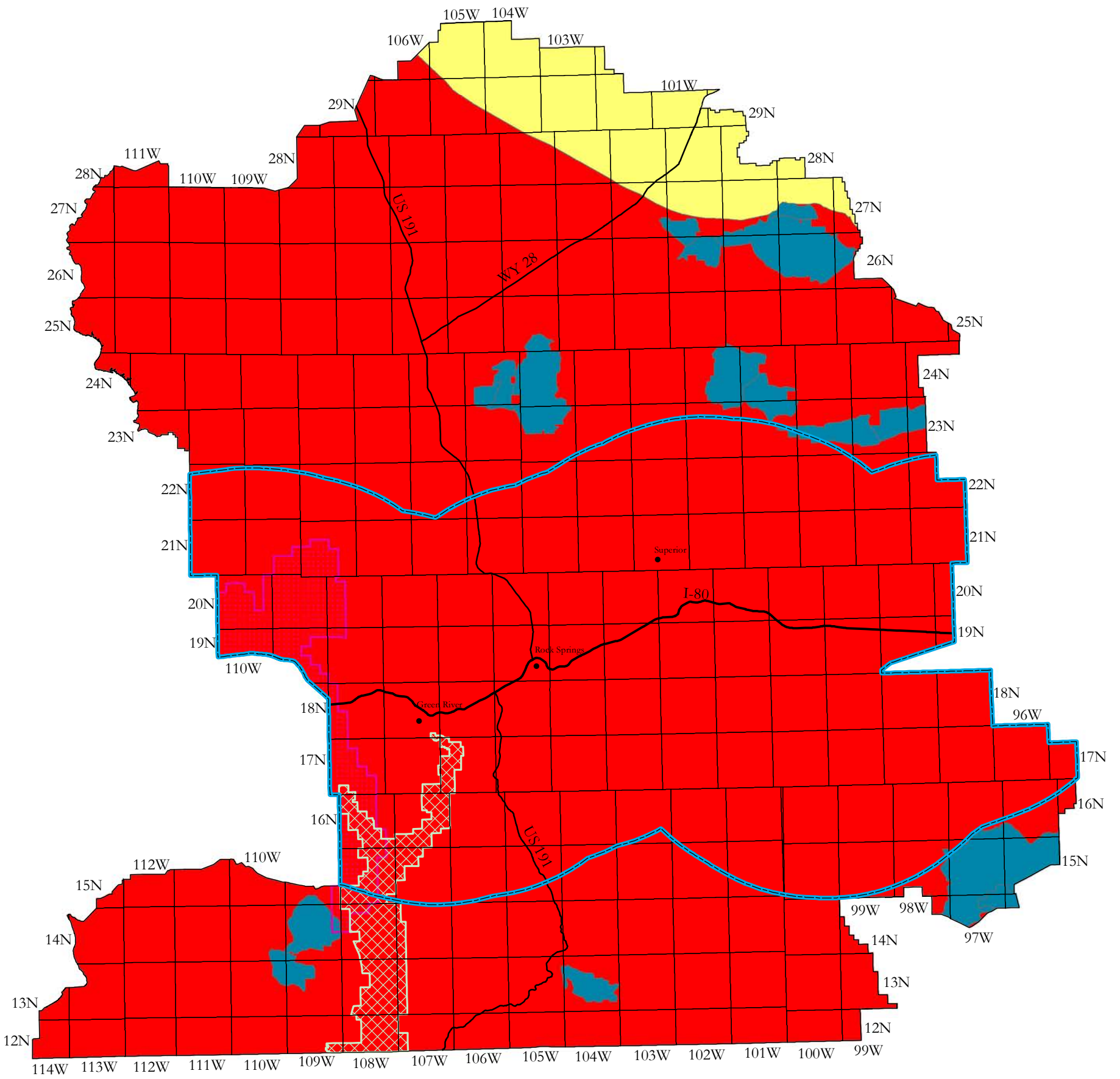
June, 2012

Dean Stilwell, Geologist
Amber Robbins, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 41.

Potential for occurrence of conventional oil and gas within the Rock Springs Planning Area.



National Forest Lands

Mechanically Mineable Trona Area

Union Pacific Railroad Land Grant

Conventional Occurrence Potential

High

Low

Wilderness Study Area -- Not Assessed

Wyoming State Office

Reservoir Management Group

0 12.5 25 50

Miles

1:800,000

N

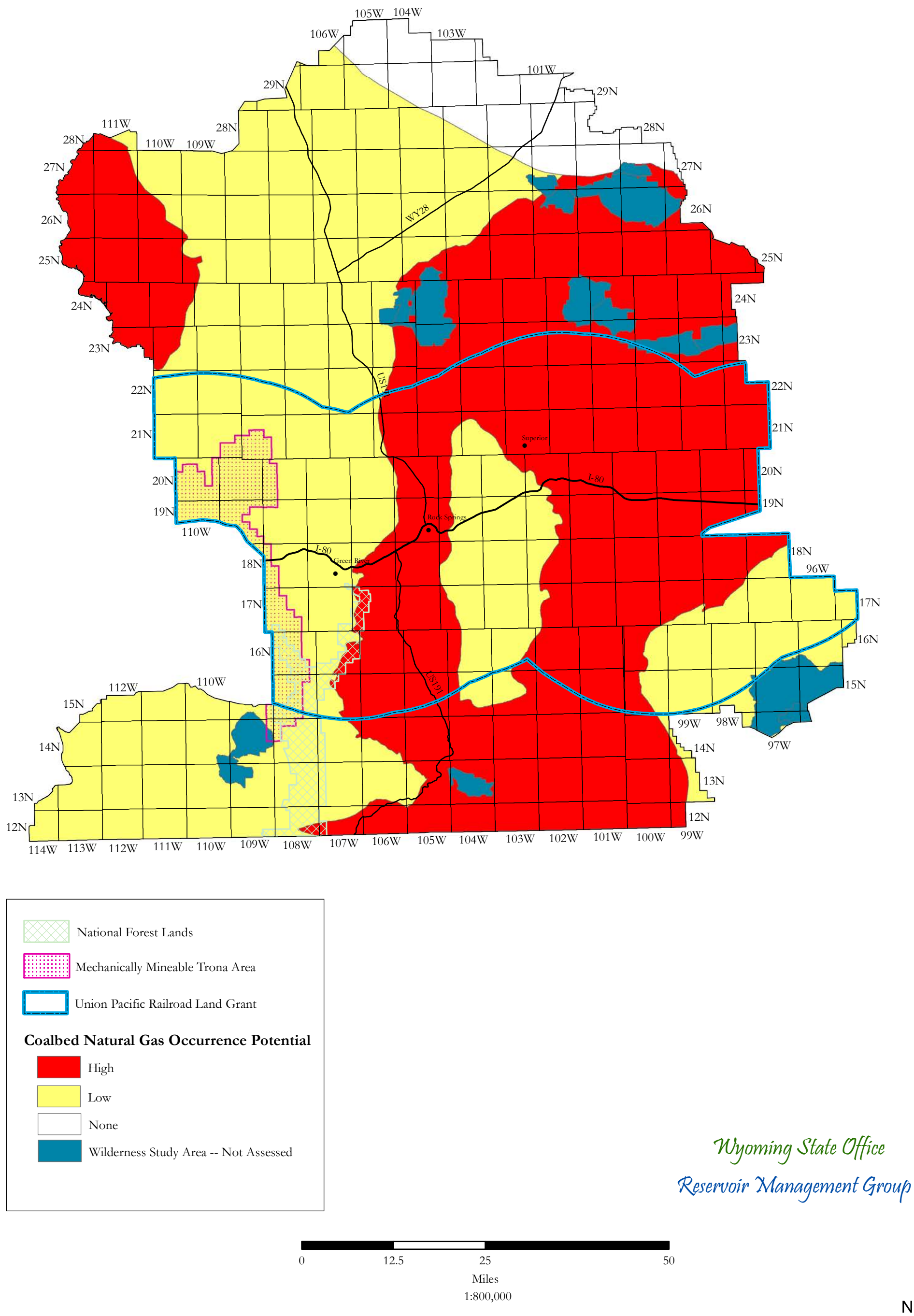
January, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 42.

Potential for occurrence of coalbed natural gas within the Rock Springs Planning Area.



January, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 43. Wyoming historical natural gas prices with future natural gas price projections (Energy Information Administration, 2012).

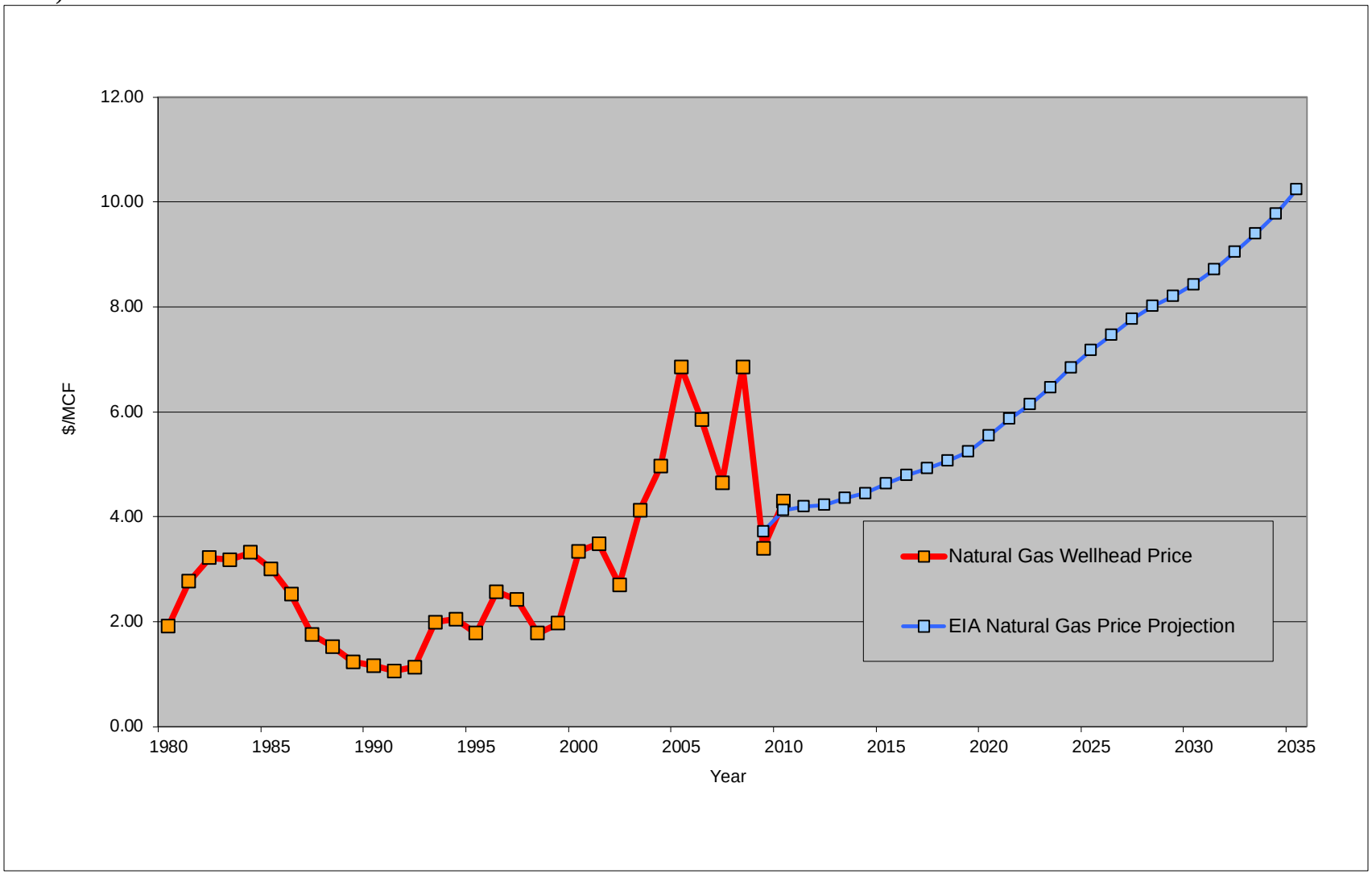


Figure 44. Wyoming historical crude oil prices with future crude oil price projections (Energy Information Administration, 2012).

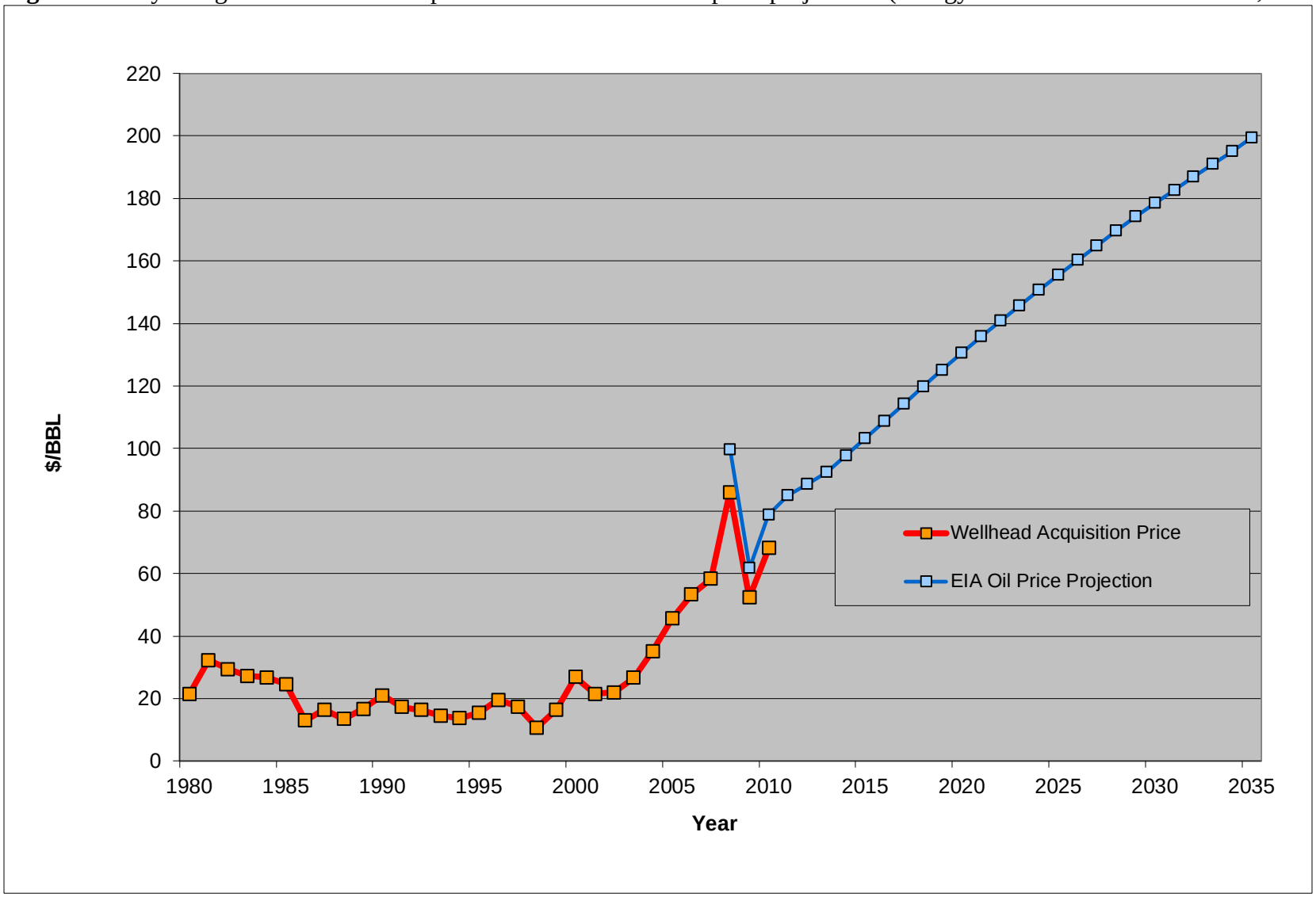
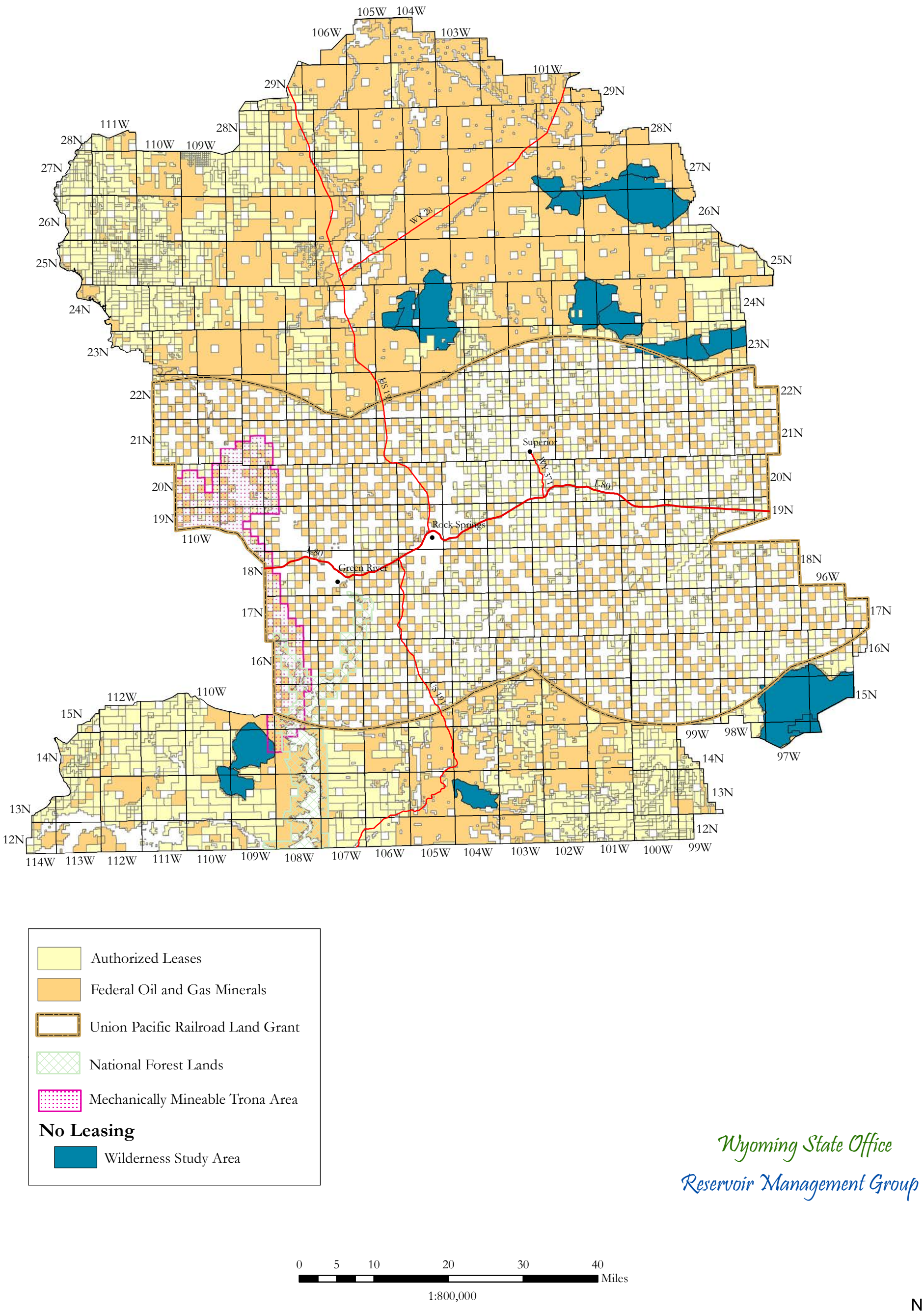


Figure 45.

Federal oil and gas minerals and authorized leases within the Rock Springs Planning Area. Data from Bureau files.



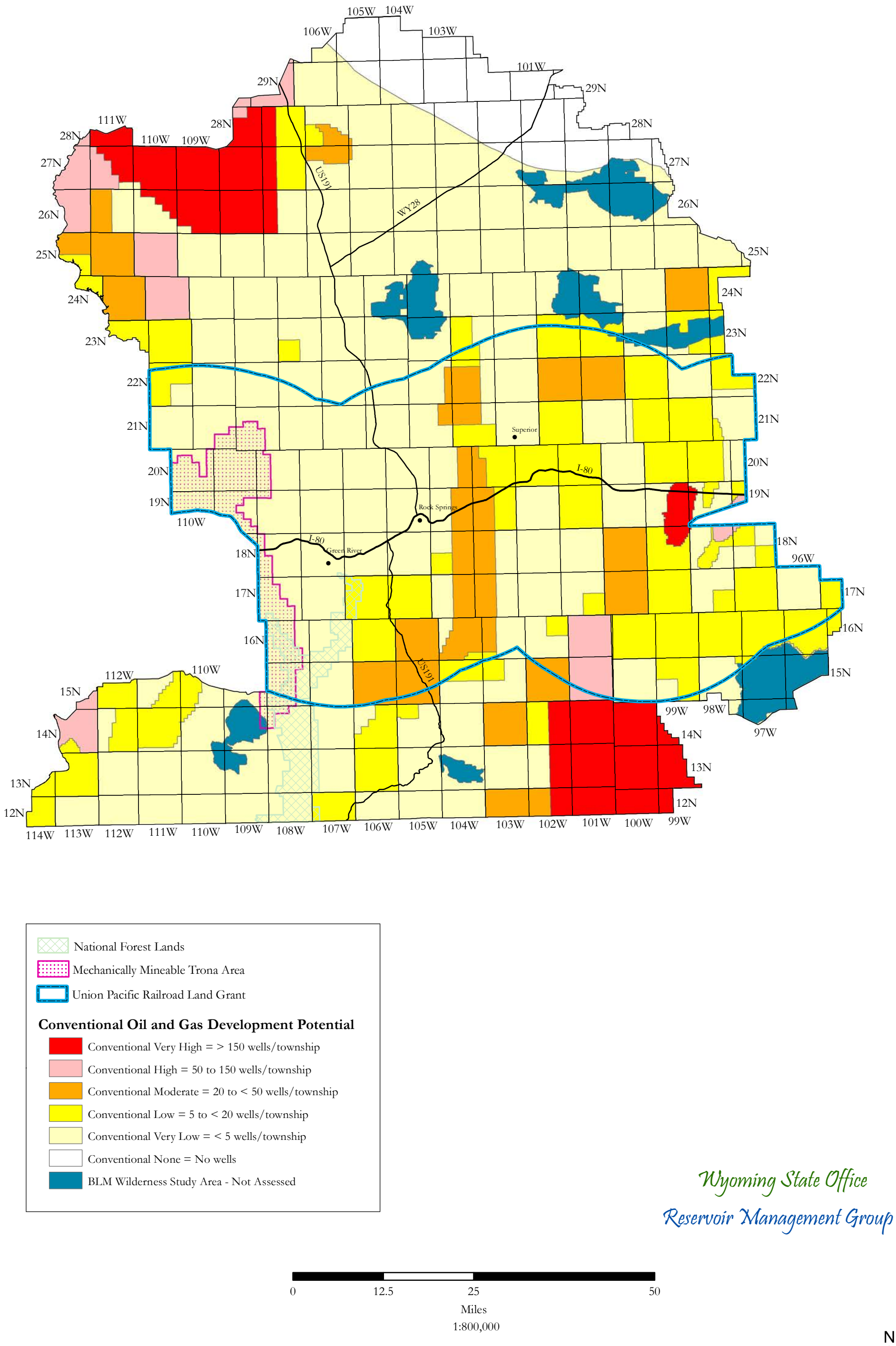
October, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 46.

Rock Springs Planning Area conventional oil and gas development potential for the analysis period (2012-2031).



Wyoming State Office
Reservoir Management Group

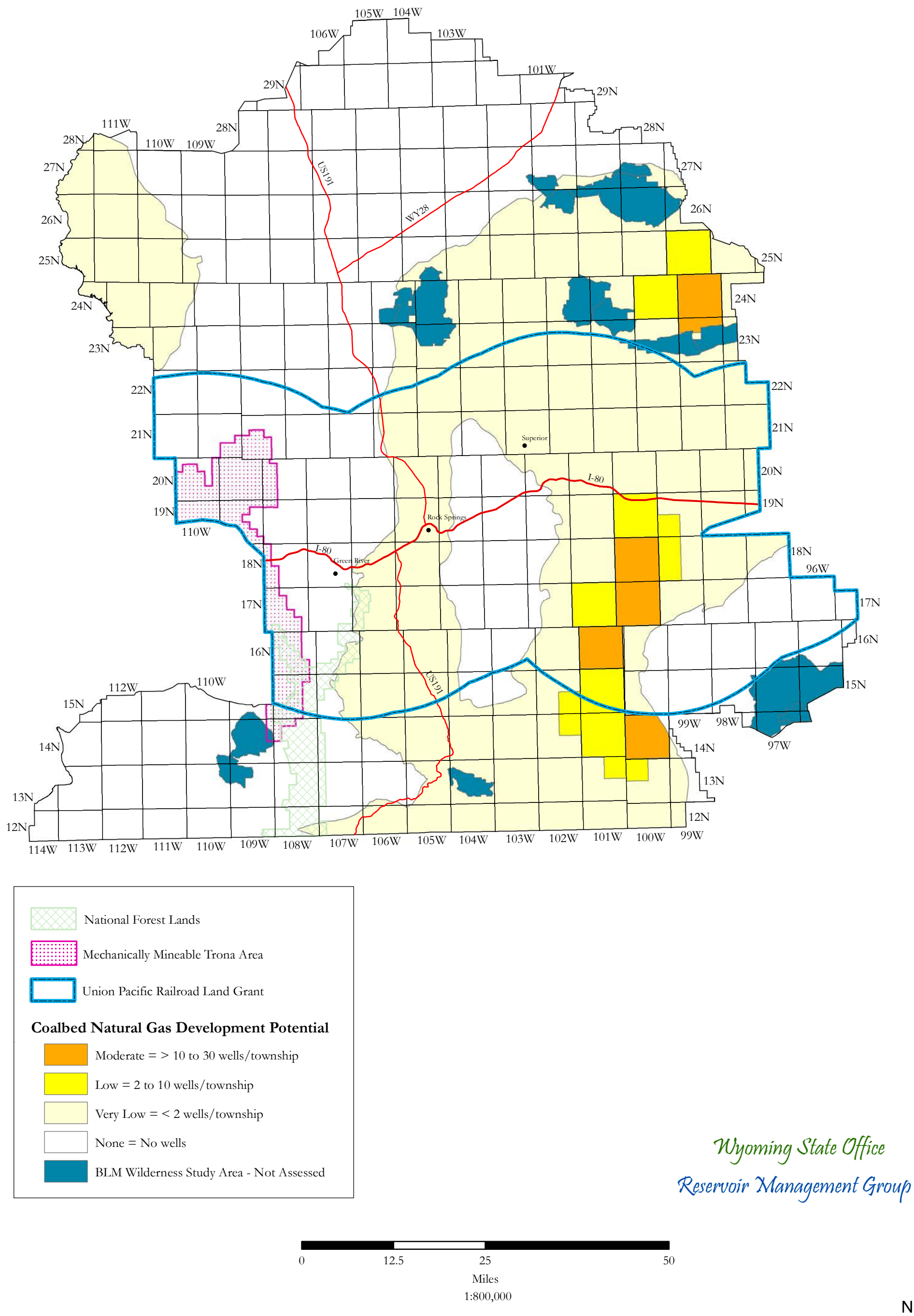
January, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 47.

Rock Springs Planning Area coalbed natural gas development potential for the analysis period (2012-2031).



January, 2012

Dean Stilwell, Geologist

No warranty is made by the Bureau of Land Management as to the accuracy, reliability, or completeness of these data for individual or aggregate use with other data. Original data was compiled from various sources. This information was developed through digital means and may be updated without notification.

Figure 48. Annual Wyoming crude oil production in thousand barrels. Data from Energy Information Administration (2012b).

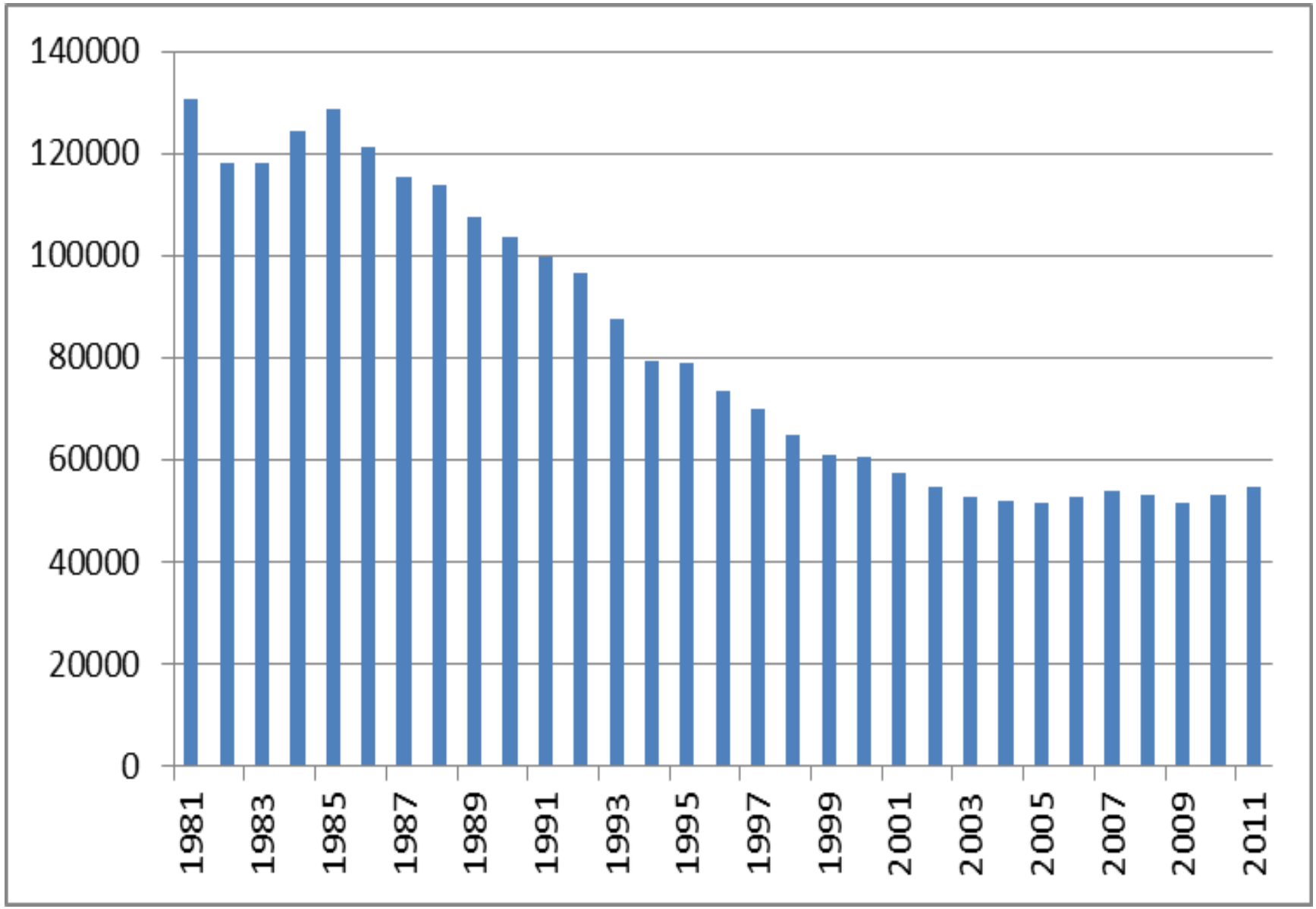


Figure 49. Annual Wyoming natural gas production in thousand cubic feet. Data from Energy Information Administration (2012c).

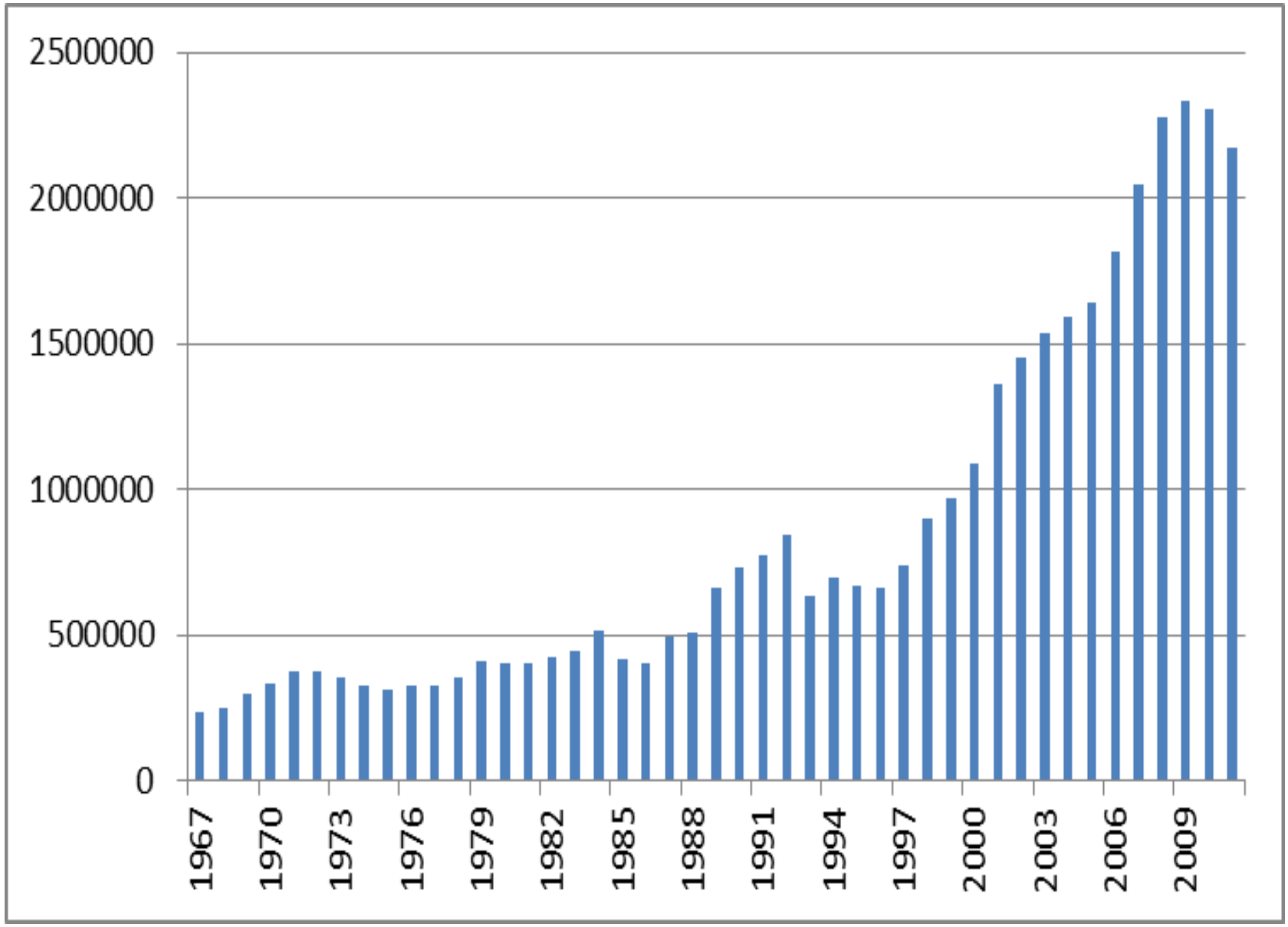


Table 1. Wildcat and development well drilling within the Rock Springs Planning Area from 1970 through 2011. Data from IHS Energy Group (2012).

	WILDCAT WELLS							DEVELOPMENT WELLS	
YEAR	NEW FIELD	OUTPOST	DEEPER POOL	SHALLOWER POOL	NEW POOL	TOTAL COMPLETED	PERCENT SUCCESSFUL	TOTAL COMPLETED	PERCENT SUCCESSFUL
1970	38	4	1			43	9	22	59
1971	21	8				29	28	27	52
1972	28	9	7	1		45	40	26	65
1973	42	10	5		2	59	32	49	57
1974	37	5	1			43	40	51	75
1975	37	6	2			45	22	52	73
1976	25	2	2	1		30	43	23	70
1977	44	13	2	1		60	35	72	63
1978	27	9	2	1		39	51	38	66
1979	34	5	1			40	38	59	64
1980	34	5	2			41	34	64	75
1981	37	8	4			49	31	58	64
1982	21	3		1		25	44	68	85
1983	6	3				9	56	78	92
1984	6					6	83	33	79
1985	3	2	1			6	83	32	84
1986		1	7			8	75	13	77
1987	7		7			14	64	39	92
1988	8		1	1		10	0	51	86
1989	9		2			11	27	45	82
1990	9		2			11	36	37	86
1991	5		1			6	50	19	84
1992	5	5				10	30	99	97
1993	10	7				17	35	53	92
1994	9	5				14	57	73	93
1995	8	2	2			12	67	26	77
1996	3	1	2	1		7	57	53	96
1997	15	3	2		2	22	45	89	96
1998	9	5				14	79	68	94
1999	5	7	1	1		14	86	43	95
2000	15	2	1			18	78	42	95
2001	21	13				34	82	80	94
2002	15	9				24	71	37	95
2003	18	6				24	71	88	93
2004	9	4	2			15	67	80	90
2005	14	3	1			18	72	49	84
2006	15	3	1			19	74	126	94
2007	9	1				10	70	98	95
2008	12	2	2			16	75	94	98
2009	3					3	33	20	90
2010	1					1	100	95	100
2011		1				1	100	47	100
TOTAL	**674**	**172**	**64**	**8**	**4**	**922**		**2316**	

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
NORTHERN HIAWATHA	Vermillion Oil Co.	3,518.00	11/1/1936	Exploratory	Terminated	7/1/1954
PINEDALE	The California Co.	73,000.00	9/16/1938	Exploratory	Terminated	11/11/1942
PACIFIC CREEK	The Superior Oil Co.	23,035.76	5/27/1943	Exploratory	Terminated	12/31/1949
ALKALI CREEK DOME	Mountain Fuel Supply Co.	13,584.25	8/1/1944	Exploratory	Terminated	7/1/1950
OREGON TRAIL	Sinclair Wyoming Oil Co.	16,000.00	2/17/1947	Exploratory	Terminated	4/10/1950
SOUTHWEST TABLE ROCK	The Texas Co.	6,000.00	12/13/1948	Exploratory	Terminated	6/7/1949
NITCHIE GULCH	Amerada Pet. Corp.	29,584.00	4/8/1949	Exploratory	Terminated	12/14/1949
LEUCITE HILLS	The Carter Oil Co.	18,878.00	5/13/1949	Exploratory	Terminated	2/19/1949
HIAWATHA	Mountain Fuel Supply Co.	26,084.33	6/23/1949	Exploratory	Terminated	12/29/1953
GRIZZLY BUTTES	Mountain Fuel Supply Co.	28,520.50	10/25/1951	Exploratory	Terminated	7/7/1952
SPRING BRANCH	The California Co.	76,174.76	11/27/1951	Exploratory	Terminated	8/25/1953
MIDDLE MOUNTAIN	Stanolind Oil & Gas Co.		12/21/1951	Exploratory	Terminated	12/9/1972
SHELL CREEK	Shell Oil Co.	92,140.41	5/27/1952	Exploratory	Terminated	12/30/1954
HALLVILLE	Cities Service Oil CoO.	14,022.67	6/30/1952	Exploratory	Terminated	4/17/1953
TRAIL	Mountain Fuel Supply Co.	10,431.71	11/7/1952	Exploratory	Terminated	1/1/1954
PINE BUTTE	Shell Oil Co.	30,462.77	3/2/1953	Exploratory	Terminated	3/25/1955
EAST SALT WELLS	General Pet. Corp.	22,388.05	12/22/1953	Exploratory	Terminated	2/1/1955
CARSON PEAK			1/4/1954	Exploratory	Terminated	1/1/1955
BUCKHORN	General Pet. Corp.	45,733.29	4/14/1954	Exploratory	Terminated	11/1/1956
SOUTHWEST TABLE ROCK	Gulf Oil Corp.	5,560.00	10/1/1954	Gas	Terminated	3/22/1974
MORROW CREEK	George J. Greer, Ttrustee	25,125.00	11/12/1954	Exploratory	Terminated	7/1/1956
NITCHIE GULCH	The Superior Oil Co.	21,172.00	6/20/1955	Exploratory	Terminated	8/1/1956
ROCK SPRINGS	Cities Service Oil CoO.	33,913.85	7/25/1955	Exploratory	Terminated	11/1/1958
INDIAN GAP	Wold & Wheatley	19,826.04	9/16/1955	Exploratory	Terminated	3/1/1958
RED DESERT	El Paso Natural Gas Co.	24,320.21	9/22/1955	Exploratory	Terminated	6/1/1956
TEPEE MOUNTAIN	Stanolind Oil & Gas Co.	9,528.83	1/3/1956	Exploratory	Terminated	3/1/1957
TWIN ROCKS	Exxon Corp.	22,525.80	2/8/1956	Exploratory	Terminated	6/29/1978
POTTER MOUNTAIN	The Britixh-American Oil Prodg. Co.	4,966.66	7/17/1956	Exploratory	Terminated	5/1/1960
PIONEER	Mountain Fuel Supply Co.	17,101.94	8/15/1956	Gas	Terminated	3/29/1975
BITTER CREEK	Shell Oil Co.	13,902.52	11/30/1956	Exploratory	Terminated	9/1/1957
STEAD CANYON	The Carter Oil Co.	10,928.32	5/10/1957	Exploratory	Terminated	9/1/1957
THAYER JUNCTION	Continental Oil Co.	14,665.00	10/18/1957	Exploratory	Terminated	5/29/1958
KINNEY RIM	Pauley Pet., Inc.	14,441.21	4/21/1958	Exploratory	Terminated	5/1/1961
CURRENT CREEK	Colorado Oil and Gas Corp.	55,194.51	7/31/1958	Exploratory	Terminated	8/1/1962
MONUMENT BUTTE	The California Oil Co.	37,945.27	8/22/1958	Exploratory	Terminated	5/31/1963
MUD LAKE	The Ohio Oil Co.	23,095.21	9/9/1958	Exploratory	Terminated	9/1/1960
HORN CANYON	Mountain Fuel Supply Co.	22,431.92	9/10/1958	Exploratory	Terminated	12/1/1959
BLACK ROCK CREEK	El Paso Natural Gas Co.	57,474.71	9/16/1958	Exploratory	Terminated	11/1/1961
BIG DUNE	Sunray Mid-Continent Oil Co.	17,674.94	1/21/1959	Exploratory	Terminated	5/1/1962
BLACK BUTTE CREEK	Decalta International Corp.	41,439.41	2/11/1959	Gas	Terminated	5/22/1979
FISHER CREEK	Humbel Oil & Refining Co.	29,134.16	3/6/1959	Exploratory	Terminated	10/1/1961
GREAT GRIZZLY	Northern Natural Gas Prodg. Co.	43,114.75	4/15/1959	Exploratory	Terminated	8/15/1960
SAND BUTTE	Continental Oil Co.	38,742.36	4/15/1959	Gas	Terminated	12/1/1966
BIRD CANYON	Pan American Pet. Corp.	20,223.84	4/24/1959	Exploratory	Terminated	9/1/1961
EDEN	Belco Pet. Corp.	10,582.02	5/21/1959	Exploratory	Terminated	12/1/1960
LANEY RIM	John L. Kemmerer, Jr.	23,095.42	6/3/1959	Exploratory	Terminated	10/1/1963
PATRICK DRAW	El Paso Natural Gas Co.	19,825.70	7/7/1959	Oil	Terminated	12/1/1964
CHICKEN SPRINGS	Signal Oil & Gas Co.	11,880.00	8/10/1959	Exploratory	Terminated	5/1/1960
TENMILE DRAW	John L. Kemmerer, Jr.	15,352.08	8/25/1959	Exploratory	Terminated	2/1/1966
SADDLE	Mid-America Minerals, Inc.	6,079.14	9/3/1959	Exploratory	Terminated	2/1/1961
MORROW CREEK	Kerr-McGee Oil Industris, Inc.	8,159.86	9/17/1959	Exploratory	Terminated	5/1/1960
CEDAR MOUNTAIN	Phillips Pet. Co.	26,826.92	9/18/1959	Exploratory	Terminated	6/1/1960
FOGARTY DRAW	Belco Pet. Corp.	15,168.44	9/23/1959	Exploratory	Terminated	9/23/1964
BURNT CANYON	Sohio Pet. Co.	32,920.38	12/9/1959	Exploratory	Terminated	11/1/1960
SANDY BEND	Belco Pet. Corp.	21,544.03	12/18/1959	Exploratory	Terminated	4/1/1961
HENRY'S FORK	Pan American Pet. Corp.	16,176.09	2/10/1960	Exploratory	Terminated	2/1/1961
LITTLE WORM CREEK	Caulkins Oil Co.	5,598.41	3/30/1960	Gas	Terminated	2/1/1961
FRANKLIN WASH	The California Oil Co.	20,154.33	6/14/1960	Exploratory	Terminated	3/1/1962
BEACON RIDGE	Texaco Explor. and Prod., Inc.	7,656.96	6/17/1960	Oil	Terminated	1/1/1965
SIMPSON GULCH	El Paso Natural Gas Co.	27,717.00	7/12/1960	Exploratory	Terminated	11/1/1960
LINWOOD	Pan American Pet. Corp.	9,873.40	7/14/1960	Exploratory	Terminated	4/1/1961
BUTCHER KNIFE SPRINGS	The Pure Oil Co.	16,969.45	10/28/1960	Exploratory	Terminated	9/1/1961
SAXON BUTTE	Texaco Explor. and Prod., Inc.	14,040.40	12/5/1960	Exploratory	Terminated	1/1/1964

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
VERMILLION CREEK	Kirby Royalties, Inc.	13,549.99	2/24/1961	Exploratory	Terminated	4/1/1963
HIAWATHA SUGARLOAF (Deep)	Mountain Fuel Supply Co.	34,899.15	3/7/1961	Exploratory	Terminated	5/1/1962
FIREHOLE	Mountain Fuel Supply Co.	22,795.12	5/12/1961	Exploratory	Terminated	8/1/1962
BROOKS DRAW	Buffalo Pet. Corp.	10,353.22	5/31/1961	Exploratory	Terminated	10/1/1961
BITTER CREEK	Continental Oil Co.	41,009.90	8/11/1961	Gas	Terminated	9/20/1968
SPIDER CREEK	Humbel Oil & Refining Co.	110,205.91	8/18/1961	Exploratory	Terminated	6/1/1963
PLUNGE	The Atlantic Refining Co.	21,087.42	10/17/1961	Exploratory	Terminated	8/1/1962
PARNELL CREEK	Humbel Oil & Refining Co.	26,182.93	11/3/1961	Exploratory	Terminated	5/1/1962
BLACKS FORK	Humbel Oil & Refining Co.	88,203.62	4/27/1962	Exploratory	Terminated	5/1/1963
MASSACRE HILL	Pan American Pet. Corp.	26,865.75	5/3/1962	Exploratory	Terminated	7/1/1965
HOMESTEAD	Mountain Fuel Supply Co.	6,038.09	6/14/1962	Exploratory	Terminated	2/13/1964
FISHER CREEK	Mountain Fuel Supply Co.	10,399.43	8/15/1962	Exploratory	Terminated	2/1/1963
SHEEP CAMP	St. Helens Pet. Corp.	53,170.40	8/31/1962	Exploratory	Terminated	5/1/1964
TABERNACLE BUTTE	Texaco Explor. and Prod., Inc.	37,017.63	11/9/1962	Exploratory	Terminated	10/1/1963
GOLDEN WALL	Mountain Fuel Supply Co.	21,037.49	4/18/1963	Exploratory	Terminated	1/1/1965
MONUMENT RIDGE	San Jacinto Pet. Corp.	31,643.94	5/29/1963	Exploratory	Terminated	2/1/1964
SCREGGS DRAW	Gulf Oil Corp.	7,957.86	6/12/1963	Exploratory	Terminated	9/11/1963
DAN'S CREEK	Davis Oil Co.	4,714.82	7/9/1963	Exploratory	Terminated	3/1/1964
KENT RANCH	Pan American Pet. Corp.	16,078.73	10/7/1963	Exploratory	Terminated	3/9/1964
BLUE RIM	Shell Oil Co.	25,015.03	5/18/1964	Exploratory	Terminated	12/1/1964
WINDMILL	Mountain Fuel Supply Co.	43,872.80	9/23/1964	Exploratory	Terminated	5/28/1965
MARSH CREEK	Cevron Oil Co.	11,521.32	11/5/1964	Exploratory	Terminated	11/1/1965
EIGHTEEN MILE CANYON	Pacific Natural Gas Corp.	21,655.37	6/16/1965	Exploratory	Terminated	4/1/1966
STAGE STOP	Anadarko Explor. & Prod. Co. LP	14,934.20	8/24/1965	Oil	Terminated	2/5/2003
IRISH CREEK	McCulloch Oil Corp.	15,363.84	6/17/1966	Exploratory	Terminated	9/1/1967
PICKETT LAKE	Gulf Oil Corp.	50,146.32	6/23/1966	Exploratory	Terminated	6/10/1967
MORROW CREEK	Gulf Oil Corp.	79,301.38	6/24/1966	Exploratory	Terminated	2/1/1968
RICHARDS MOUNTAIN	Mountain Fuel Supply Co.	15,999.98	10/10/1966	Exploratory	Terminated	1/9/1968
PINNACLES	Wolf Explor. Co.	150,024.10	3/21/1967	Exploratory	Terminated	6/1/1968
BURNT FORK	Mobil Oil Corp.	47,919.65	4/25/1967	Exploratory	Terminated	6/15/1967
JIM SPRING	Energy Reserves Group	4,495.64	6/9/1967	Exploratory	Terminated	10/21/1976
ANTELOPE CREEK	Continental Oil Co.	7,680.00	8/11/1967	Exploratory	Terminated	11/1/1968
CROOKED WASH	Mountain Fuel Supply Co.	18,761.56	7/23/1968	Exploratory	Terminated	1/23/1970
JESSEN BUTTE	Forest Oil Corp.	20,304.68	8/8/1968	Exploratory	Terminated	11/19/1969
FONTENELLE	Chorney Oil Co.	37,361.88	8/15/1968	Exploratory	Terminated	2/1/1970
SUGARLOAF (Deep)	Texaco Explor. and Prod., Inc.	23,142.76	3/3/1969	Exploratory	Terminated	5/1/1970
BROKEN HAND	Chorney Oil Co.	27,005.23	7/22/1969	Exploratory	Terminated	3/2/1971
PRAIRIE HEN	Chorney Oil Co.	99,606.77	8/12/1969	Exploratory	Terminated	11/15/1970
SPUR CREEK	Belco Pet. Corp.	9,129.22	8/28/1969	Oil	Terminated	2/1/1976
LOMBARD CANYON	Chorney Oil Co.	94,305.36	11/4/1969	Exploratory	Terminated	4/22/1972
ROCK BLUFFS	Chorney Oil Co.	78,240.17	12/5/1969	Exploratory	Terminated	6/20/1971
MILLER MOUNTAIN	Midwest Oil Corp.	35,838.65	2/20/1970	Exploratory	Terminated	9/29/1971
DICKIE SPRINGS	Mountain Fuel Supply Co.	13,073.96	4/28/1970	Exploratory	Terminated	
SANDY CREEK	Champlin Pet. Co.	35,040.46	7/9/1970	Exploratory	Terminated	4/1/1971
CIRCLE BAR	Chorney Oil Co.	56,876.66	1/15/1971	Exploratory	Terminated	
BUCKHORN	Mountain Fuel Supply Co.	17,649.34	4/12/1971	Exploratory	Terminated	12/15/1971
WHITE MOUNTAIN	Union Oil Co.	15,283.59	9/30/1971	Exploratory	Terminated	11/2/1972
MIDDLE MOUNTAIN SOUTH	Phillips Pet. Co.	37,745.79	2/4/1972	Exploratory	Terminated	12/9/1972
TRAPPERS TRAIL	Gulf Oil Corp.	104,906.27	5/23/1972	Exploratory	Terminated	11/1/1976
BIG HOLLOW	Devon Corp.	15,953.23	6/16/1972	Exploratory	Terminated	3/26/1974
EDEN	Husky Oil Co.	39,127.12	8/18/1972	Exploratory	Terminated	9/1/1975
WHITE FEATHER	Colorado Oil and Gas Corp.	30,149.37	5/7/1973	Exploratory	Terminated	3/21/1974
WILKINS PEAK	Miami Oil Producers, Inc.	34,488.96	6/20/1973	Exploratory	Terminated	4/6/1974
FIREHOLE	Miami Oil Producers, Inc.	32,532.13	6/22/1973	Exploratory	Terminated	1/14/1974
BIG SANDY	Husky Oil Co.	30,012.44	7/10/1973	Exploratory	Terminated	3/31/1974
MONUMENT BUTTE II	Energetics, Inc.	26,257.24	8/10/1973	Exploratory	Terminated	9/1/1974
PACIFIC CREEK II	Terra Resources, Inc.	15,939.29	9/27/1973	Exploratory	Terminated	7/23/1975
LEO	Texaco Explor. and Prod., Inc.	27,162.60	10/24/1973	Exploratory	Terminated	4/12/1976
RED CREEK	Exxon Co., USA	7,038.37	11/21/1973	Exploratory	Terminated	3/30/1975
LONG ISLAND II	Belco Pet. Corp.	16,452.57	12/5/1973	Exploratory	Terminated	2/15/1974
MIKE	Marathon Oil Co.	9,910.37	12/19/1973	Exploratory	Terminated	2/25/1974
MARSH CREEK	Lone Star Prodg. Co.	21,065.12	12/19/1973	Exploratory	Terminated	7/14/1975
CURRANT CREEK	Tom Brown, Inc.	23,625.59	3/12/1974	Exploratory	Terminated	7/23/1976
SALT WELLS SOUTH	Exxon Corp.	4,400.00	5/17/1974	Exploratory	Terminated	10/1/1974

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
KENT RANCH II	Mountain Fuel Supply Co.	11,520.12	6/14/1974	Exploratory	Terminated	12/22/1975
HENRY	Brinkerhoff Drilling Co., Inc.	16,855.34	7/22/1974	Exploratory	Terminated	12/8/1975
HENRYS FORK II	Phillips Pet. Co.	11,602.54	7/31/1974	Exploratory	Terminated	11/13/1974
BIG RIDGE	Devon Corp.	12,790.53	9/4/1974	Exploratory	Terminated	10/19/1975
MILLER MOUNTAIN II	Jerry Chambers-Oil Producer	27,877.46	9/30/1974	Exploratory	Terminated	8/11/1975
SANDY BEND II	Wolf Energy Co.	33,049.22	12/17/1974	Exploratory	Terminated	12/16/1975
STORM SHELTER	Presidio Oil Co.	14,361.48	1/23/1975	Gas	Terminated	6/15/1994
SUBLETTE'S FLAT	Davis Oil Co.	31,951.33	2/4/1975	Exploratory	Terminated	9/30/1975
FISHER CREEK	Chandler & Assoc., Inc.	14,877.88	2/26/1975	Exploratory	Terminated	10/7/1975
EIGHTEEN MILE CANYON	Davis Oil Co.	27,389.89	3/11/1975	Exploratory	Terminated	1/23/1976
DELANEY RIM	Anadarko Explor. & Prod. Co. LP	36,355.55	3/17/1975	Gas	Terminated	1/8/2010
TWIN BUTTES	Farmers Union Central Exch., Inc.	29,401.60	6/17/1975	Exploratory	Terminated	9/23/1975
BLUE RIM	Wolf Energy Co.	30,257.41	6/20/1975	Exploratory	Terminated	2/19/1976
TRIPP RANCH	Davis Oil Co.	15,870.86	6/30/1975	Exploratory	Terminated	6/21/1976
GRAVEL	Amoco Prod. Co.	34,415.13	7/25/1975	Exploratory	Terminated	9/9/1976
YELLOW POINT RIDGE	Davis Oil Co.	29,195.17	7/29/1975	Exploratory	Terminated	11/27/1976
SALAZAR	CIG Explor., Inc.	31,903.76	7/29/1975	Exploratory	Terminated	5/15/1977
RED MOUNTAIN	Phillips Pet. Co.	26,741.94	7/30/1975	Exploratory	Terminated	
SIMSON GULCH	Davis Oil Co.	32,187.61	7/31/1975	Exploratory	Terminated	11/25/1976
TEPEE MOUNTAIN II	Marathon Oil Co.	14,346.44	10/30/1975	Exploratory	Terminated	2/22/1977
HORN CANYON	HPC, Inc.	29,513.53	11/19/1975	Gas	Terminated	10/3/1988
TARTER'S ISLAND	Belco Pet. Corp.	20,788.54	12/4/1975	Oil	Terminated	7/21/1981
COON DRAW	True Oil Co.	2,560.00	1/23/1976	Exploratory	Terminated	11/5/1976
TITSWORTH GAP	Impel Corp.	5,040.19	2/19/1976	Exploratory	Terminated	3/17/1977
COUNTY LINE	Davis Oil Co.	29,823.09	3/12/1976	Exploratory	Terminated	3/1/1977
BUCKHORN	Davis Oil Co.	29,552.30	6/11/1976	Exploratory	Terminated	11/23/1976
MONUMENT BUTTE III	Energetics, Inc.	24,337.24	7/7/1976	Exploratory	Terminated	8/13/1976
LITTLE MONUMENT	Samedan Oil Corp.	8,320.00	9/22/1976	Exploratory	Terminated	3/31/1977
LUMEN ROAD	Davis Oil Co.	31,274.41	11/2/1976	Exploratory	Terminated	12/28/1977
STEAD CANYON EAST	Sing Well Service, Inc.	4,406.35	11/26/1976	Exploratory	Terminated	9/1/1977
LINCOLN ROAD	Enstar Pet. Co.	17,156.18	12/14/1976	Gas	Terminated	7/30/1979
BIG WIND	Davis Oil Co.	12,091.66	4/7/1977	Exploratory	Terminated	7/29/1977
SCHEGGS DRAW	Samedan Oil Corp.	10,169.14	4/7/1977	Exploratory	Terminated	8/10/1977
DINES	Kestrel Energy, Inc.	15,787.43	4/11/1977	Exploratory	Terminated	7/5/2007
JACKALOPE	Davis Oil Co.	9,436.92	4/20/1977	Exploratory	Terminated	11/7/1977
SKUNK CANYON	Husky Oil Co.	15,740.93	5/17/1977	Exploratory	Terminated	11/2/1977
CAIRN	Husky Oil Co.	23,626.51	5/18/1977	Exploratory	Terminated	11/2/1977
FERRY ISLAND	Davis Oil Co.	26,524.74	6/1/1977	Exploratory	Terminated	8/27/1979
PERU SIDING	Husky Oil Co.	18,210.92	6/22/1977	Exploratory	Terminated	9/27/1977
LEO II	Wodds Pet. Co.	24,922.60	7/15/1977	Exploratory	Terminated	4/11/1978
BASTARD BUTTE	Davis Oil Co.	20,876.90	7/25/1977	Exploratory	Terminated	8/3/1979
MASSACRE HILLS	Husky Oil Co.	25,159.70	8/22/1977	Exploratory	Terminated	8/20/1979
BLACK ROCK CREEK	Northwest Explor. Co.	24,879.98	9/23/1977	Exploratory	Terminated	4/7/1978
KENT RANCH III	King Rresources Co.	19,172.40	11/11/1977	Exploratory	Terminated	3/31/1978
BLUE RIM II	Forest Oil Corp.	21,758.59	11/22/1977	Exploratory	Terminated	2/15/1978
SUGARLOAF	Davis Oil Co.	25,237.93	2/14/1978	Exploratory	Terminated	11/24/1978
GREATER PACIFIC CREEK	Rainbow Resources, Inc.	31,338.26	3/10/1978	Exploratory	Terminated	10/1/1980
FIVE FINGERS	Davis Oil Co.	12,778.62	4/13/1978	Exploratory	Terminated	11/30/1979
BURNT FORK	Texaco Explor. and Prod., Inc.	25,002.53	5/23/1978	Exploratory	Terminated	10/7/1979
SCHEGGS DRAW II	Jerry Chambers-Oil Producer	12,895.76	6/22/1978	Exploratory	Terminated	8/23/1978
ADOBE TOWN	Conwest Explor., Inc.	39,602.66	6/23/1978	Gas	Terminated	1/8/2002
SLATE CREEK	John H. Christmann	10,769.92	8/7/1978	Exploratory	Terminated	9/5/1978
LOST VALLEY	Wodds Pet. Co.	40,370.51	8/7/1978	Exploratory	Terminated	11/30/1985
RIGBY ROAD	Davis Oil Co.	24,520.09	8/31/1978	Exploratory	Terminated	4/18/1979
SANDY	Davis Oil Co.	24,717.21	9/15/1978	Exploratory	Terminated	11/24/1978
FOUR J	Energy Reserves Group	8,990.80	9/26/1978	Exploratory	Terminated	10/10/1978
SCOTTY LAKE	Davis Oil Co.	24,780.41	11/2/1978	Exploratory	Terminated	7/21/1980
PARRISH MARK	Davis Oil Co.	24,868.06	11/27/1978	Exploratory	Terminated	2/13/1979
TWIN FORK	Koch Explor. Co.	22,431.98	11/29/1978	Exploratory	Terminated	2/27/1979
FIREHOLE	Husky Oil Co.	18,457.55	12/6/1978	Exploratory	Terminated	3/24/1980
BRIGHT TRAIL	Davis Oil Co.	24,892.42	1/4/1979	Exploratory	Terminated	12/2/1979
PACKSADDLE	Wodds Pet. Corp.	24,778.69	2/27/1979	Exploratory	Terminated	7/30/1979
HONEYCOMB BUTTES	Davis Oil Co.	24,968.97	3/29/1979	Exploratory	Terminated	4/3/1980
QUICKSILVER	Davis Oil Co.	12,160.24	3/29/1979	Exploratory	Terminated	9/26/1980

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
SIMSON	Davis Oil Co.	24,717.21	5/29/1979	Exploratory	Terminated	3/16/1980
SHALLOW CREEK	Forceenergy, Inc.	22,892.29	6/1/1979	Gas	Terminated	2/29/1996
TREASURE	Blackjack Oil, Inc.	24,797.47	6/20/1979	Gas	Terminated	4/5/2002
BOAR'S TUSK	FMC Corp.	11,520.00	6/25/1979	Gas	Terminated	10/9/1986
MOUNTAIN	Energy Reserves Group	9,150.80	6/28/1979	Exploratory	Terminated	1/27/1981
JONAH GULCH	Forest Oil Corp.	23,639.74	11/21/1979	Exploratory	Terminated	3/7/1980
McCORT CANYON	Anadarko Prod. Co.	8,202.75	4/25/1980	Exploratory	Terminated	2/13/1981
ROCKY CROSSING	Davis Oil Co.	25,424.02	4/29/1980	Exploratory	Terminated	4/2/1981
ESSEX MOUNTAIN	Houston Oil & Minerals Corp.	10,116.24	5/6/1980	Gas	Terminated	10/18/1984
BASIN WELL	Davis Oil Co.	24,549.00	5/19/1980	Exploratory	Terminated	3/30/1981
HAGUE HILL	Texas OilL & Gas	10,184.93	5/27/1980	Exploratory	Terminated	2/1/1981
HOURGLASS	Wodds Pet. Co.	24,889.44	5/30/1980	Exploratory	Terminated	5/28/1981
ROCK CABIN	Wodds Pet. Corp.	15,335.50	6/27/1980	Exploratory	Terminated	3/28/1982
HARRIS SLOUGH	Davis Oil Co.	24,982.64	8/12/1980	Exploratory	Terminated	7/15/1981
MOUNT COFFIN	Wodds Pet. Corp.	24,584.39	8/13/1980	Exploratory	Terminated	11/24/1982
SINK HOLE	Wodds Pet. Corp.	10,214.56	9/29/1980	Exploratory	Terminated	1/29/1981
GOLDENROD	Davis Oil Co.	24,100.70	10/20/1980	Exploratory	Terminated	11/20/1980
PIRATE	Davis Oil Co.	10,165.10	10/31/1980	Exploratory	Terminated	2/27/1981
PRONGHORN	Anadarko Prod. Co.	5,712.93	11/6/1980	Exploratory	Terminated	8/26/1981
ASPIRIN	Davis Oil Co.	23,444.14	11/17/1980	Exploratory	Terminated	2/4/1981
CUTLASS	Wodds Pet. Corp.	24,584.39	12/31/1980	Exploratory	Terminated	11/17/1982
OLD ROAD	Davis Oil Co.	22,319.02	1/29/1981	Exploratory	Terminated	9/23/1981
FREIGHTER GAP	Wodds Pet. Corp.	24,655.86	2/9/1981	Gas	Terminated	7/11/1987
FLAMING GORGE	Hunt Energy Corp.	15,352.05	2/25/1981	Exploratory	Terminated	3/24/1983
SOUTH PASS	Amoco Prod. Co.	24,919.52	3/23/1981	Exploratory	Terminated	6/24/1983
PRETTY WATER CREEK	Ibex Resources Operating LLC	6,554.52	3/26/1981	Gas	Terminated	8/27/2007
EDWARDS RANCH	Helmerich & Payne, Inc.	21,929.97	4/6/1981	Exploratory	Terminated	6/21/1982
CENTURION	Wodds Pet. Corp.	29,988.43	4/28/1981	Exploratory	Terminated	7/16/1981
SADDLEBAG	Wodds Pet. Corp.	26,083.44	5/28/1981	Exploratory	Terminated	10/24/1982
GRIZZLY BUTTE	Forest Oil Corp.	13,561.74	5/29/1981	Exploratory	Terminated	11/29/1981
FARAWAY	Davis Oil Co.	23,307.67	6/15/1981	Exploratory	Terminated	2/10/1982
MUSKATEER	Davis Oil Co.	23,625.63	6/30/1981	Exploratory	Terminated	5/17/1982
BALD EAGLE	Santa Fe Energy Co.	16,700.00	7/27/1981	Exploratory	Terminated	7/25/1983
ENTERPRISE	Davis Oil Co.	22,724.25	8/6/1981	Exploratory	Terminated	2/25/1982
ANDERSON RIDGE	Robert E. Skinner	12,783.28	9/14/1981	Exploratory	Terminated	1/25/1983
MONUMENT DRAW	American Quasar Pet. Co.	13,389.28	9/17/1981	Exploratory	Terminated	12/29/1981
CHAPEL CANYON	Belco Pet. Corp.	19,062.37	10/8/1981	Exploratory	Terminated	1/17/1983
CITATION	Wodds Pet. Corp.	24,949.00	11/30/1981	Exploratory	Terminated	5/17/1982
DAVIS CABIN	Anschutz Corp.	3,080.00	12/8/1981	Exploratory	Terminated	8/10/1982
PICKETT CREEK	European Southwest Co.	14,574.32	5/21/1982	Exploratory	Terminated	10/5/1982
CONTINENTAL PEAK	European Southwest Co.	12,812.91	6/17/1982	Exploratory	Terminated	8/27/1982
JEFFERSON	Iron Mountain Operating, LLC	23,287.94	7/15/1982	Gas	Terminated	5/14/2009
SANDS OF TIME	W. A. Moncrief, Jr.	24,878.54	3/11/1983	Exploratory	Terminated	5/19/1983
OASIS	W. A. Moncrief, Jr.	24,677.22	12/27/1983	Exploratory	Terminated	5/15/1984
TWELVE MILE ROAD	Energetics Operating Co.	13,903.59	1/30/1984	Exploratory	Terminated	7/30/1984
NORTH SWEETWATER	Robert E. Skinner	40,151.28	3/16/1984	Exploratory	Terminated	1/1/1986
SOUTH SWEETWATER	E.S.W. Sweetwater Partnership	31,645.28	3/23/1984	Exploratory	Terminated	2/1/1986
TRI-COUNTY II	Exxon Corp.	9,275.50	9/21/1984	Exploratory	Terminated	9/1/1985
SOAP HOLES	Sun Explor. & Prod. Co.	7,908.52	10/4/1984	Exploratory	Terminated	12/21/1985
DESERT ROSE	Exxon Co., USA	28,144.34	10/30/1985	Exploratory	Terminated	3/15/1987
DOG SPRING	Celsius Energy Co.	12,522.84	10/30/1985	Exploratory	Terminated	10/10/1989
WILDFIRE	Sun Explor. & Prod. Co.	21,768.41	4/22/1986	Exploratory	Terminated	10/22/1986
JONAH	Home Pet. Corp., Inc.	24,780.73	9/26/1986	Exploratory	Terminated	3/9/1989
WILLOW RIM	Sun Explor. & Prod. Co.	25,749.32	8/24/1987	Exploratory	Terminated	7/19/1988
IRISH SPRING	Sun Explor. & Prod. Co.	11,494.34	9/15/1987	Exploratory	Terminated	3/15/1988
WADSWORTH	Sun Explor. & Prod. Co.	24,199.94	2/1/1988	Exploratory	Terminated	10/26/1989
YELLOW SPUR	Sun Explor. & Prod. Co.	7,607.00	2/2/1988	Exploratory	Terminated	2/26/1988
SUDS DRAW	ThermalL Explor., Inc.	19,621.32	4/27/1988	Exploratory	Terminated	12/14/1990
LITTLE COLORADO	General Atlantic Energy Corp.	21,346.76	6/28/1988	Exploratory	Terminated	11/23/1988
HUNGRY HOLLOW	Union Pacific Resources Co.	19,956.79	7/21/1988	Exploratory	Terminated	2/10/1989
DUGWAY	Union Pacific Resources Co.	15,877.45	10/27/1988	Exploratory	Terminated	10/26/1989
CYGNUS	Presidio Explor., Inc.	6,939.25	11/28/1989	Exploratory	Terminated	11/30/1990
LIFEBUOY	Oryx Energy Co.	7,607.00	12/14/1989	Exploratory	Terminated	2/15/1990
PARIS	Presidio Explor., Inc.	26,429.20	2/5/1990	Exploratory	Terminated	10/27/1990

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
MUSTANG	Union Pacific Resources Co.	18,756.48	10/30/1990	Exploratory	Invalid, ab initio	5/9/1991
BUSH CREEK	True Oil Co.	22,106.80	11/2/1990	Exploratory	Terminated	1/23/1991
SHETLAND	Union Pacific Resources Co.	2,404.31	12/21/1990	Exploratory	Terminated	7/19/1991
YELLOW POINT	Presidio Explor., Inc.	5,118.98	1/31/1991	Exploratory	Terminated	8/26/1991
STINGER	Union Pacific Resources Co.	16,618.25	5/22/1991	Exploratory	Invalid, ab initio	10/1/1991
ANTELOPE HOLLOW	Hallwood Energy Co.	12,108.03	7/29/1991	Exploratory	Terminated	9/30/1992
WILLOW RESERVOIR	Questar Explor. & Prod. Co.	10,419.69	9/5/1991	Gas	Terminated	8/20/2004
GLASNOST	Union Pacific Resources Co.	6,915.83	10/28/1991	Exploratory	Terminated	11/30/1992
BLUEWATER	Union Pacific Resources Co.	10,237.02	11/19/1991	Exploratory	Terminated	12/21/1992
TIMBER ROCK	Presidio Explor., Inc.	26,877.90	2/24/1992	Exploratory	Terminated	10/13/1992
WILD TURKEY	Anadarko Pet. Corp.	7,120.00	2/28/1992	Exploratory	Terminated	8/11/1992
EIGHTEEN MILE	Presidio Explor., Inc.	26,341.78	4/16/1992	Exploratory	Terminated	11/27/1992
JEEP TRAIL	Celsius Energy Co.	5,760.00	7/7/1992	Exploratory	Terminated	5/26/1994
BLAZING STAR	Celsius Energy Co.	3,898.92	8/17/1992	Exploratory	Invalid, ab initio	2/17/1993
SOUTH HAY RESERVOIR	Marsh Operating Co.	3,092.03	10/23/1992	Exploratory	Terminated	5/25/1993
RESERVOIR	Cabot Oil & Gas Prod. Corp.	9,868.07	12/28/1992	Exploratory	Terminated	5/26/1995
TWELVEMILE GULCH	Yates Pet. Corp.	15,346.83	7/29/1993	Exploratory	Terminated	5/16/1994
PIETRA	Yates Pet. Corp.	27,184.78	7/29/1993	Exploratory	Terminated	6/10/1995
WHITEHORSE CREEK	Barrett Resources Corp.	13,431.46	8/11/1993	Exploratory	Terminated	2/28/1994
THUNDERER	Union Pacific Resources Co.	1,280.00	12/28/1993	Exploratory	Terminated	8/31/1994
JOHNSON GAP (Deep)	St. Mart Land & Explor. Co.	25,970.49	2/28/1994	Exploratory	Invalid, ab initio	2/28/1994
BULL DRAW	CNG Prodg. Co.	22,837.32	6/3/1994	Exploratory	Terminated	6/12/1995
ELKHORN	CNG Prodg. Co.	23,529.86	7/11/1994	Exploratory	Terminated	5/6/1995
BIRCH SPRING	Preston Oil Co., LP	12,108.03	7/20/1994	Exploratory	Terminated	9/27/1994
BIG CONE	Texaco Explor. and Prod., Inc.	24,906.32	8/12/1994	Exploratory	Terminated	12/18/1995
BROOKLYN	Plains Pet. Operating Co.	25,903.74	10/28/1994	Exploratory	Terminated	5/30/1995
SUBLETTE FLATS	Snyder Oil Corp.	25,516.25	11/29/1994	Exploratory	Terminated	10/2/1995
CLAY BUTTES	Vastar Resources, Inc.	12,120.62	11/30/1994	Exploratory	Terminated	6/10/1996
RIVA	BTA Oil Producers	13,178.90	12/2/1994	Exploratory	Terminated	6/22/1995
STRATOS	Union Pacific Resources Co.	11,837.86	4/26/1995	Exploratory	Terminated	8/9/1996
GOLDEN GATE	Plains Pet. Operating Co.	25,173.07	5/23/1995	Exploratory	Terminated	12/27/1995
TABLE WASH	Basin Explor., Inc.	1,280.00	5/31/1995	Exploratory	Terminated	1/26/1996
BIG BEAR	HS Rresources, Inc.	25,624.51	5/31/1995	Exploratory	Terminated	7/7/1996
SAGE STAR	Celsius Energy Co.	4,880.48	6/14/1995	Exploratory	Terminated	9/21/1995
SNAGGLETOOTH	Celsius Energy Co.	10,481.60	10/17/1995	Exploratory	Terminated	12/13/1995
WABASH CANNONBALL	Yates Pet. Corp.	33,469.94	10/25/1995	Exploratory	Terminated	1/21/1998
SEEDSKADEE	Celsius Energy Co.	12,608.66	11/22/1995	Exploratory	Terminated	11/20/1997
SAND CASTLE	Bataa Oil, Inc.	15,314.50	2/27/1996	Exploratory	Terminated	6/24/1997
WADICKEY	Energy Group, LLC	6,229.64	7/31/1996	Exploratory	Invalid, ab initio	7/31/1996
ROCK ISLAND	Yates Pet. Corp.	22,138.50	10/21/1996	Exploratory	Terminated	10/19/1998
CANTINA	Snyder Oil Corp.	24,245.12	12/23/1996	Exploratory	Terminated	9/7/1997
SAGE FLAT (Deep)	Union Pacific Resources Co.	145,283.95	12/31/1996	Exploratory	Terminated	10/1/2000
JADE	BTA Oil Producers	21,906.61	2/19/1997	Exploratory	Terminated	7/1/1998
ENCORE	Yates Pet. Corp.	4,406.60	3/25/1997	Exploratory	Terminated	2/17/1998
SHOOTING STAR	Celsius Energy Co.	4,880.16	7/15/1997	Exploratory	Terminated	4/23/1998
DOUBLE GUN	Celsius Energy Co.	16,156.84	8/20/1997	Exploratory	Terminated	9/5/1998
TOT	Union Pacific Resources Co.	22,022.11	9/9/1997	Exploratory	Terminated	9/1/1999
GUNSMOKE	Yates Pet. Corp.	30,047.10	10/2/1997	Exploratory	Terminated	7/17/1999
GOLD COAST	Kerr-McGee/Anadarko E&P LP	25,585.25	1/30/1998	Exploratory	Terminated	1/19/2007
WEST 187	Barlow & Haun, Inc.	4,493.28	2/25/1998	Exploratory	Invalid, ab initio	2/25/1998
OUTLAW	Vastar Resources, Inc.	12,746.69	5/8/1998	Exploratory	Terminated	9/15/1998
EL NINO	Snyder Oil Corp.	20,424.81	6/5/1998	Exploratory	Terminated	4/12/1999
SCARLET	Encana Oil & Gas (USA), Inc.	23,610.35	9/2/1998	Exploratory	Terminated	1/21/2007
HORSETHIEF CANYON (Shallow)	Fancher Oil Co. LLC	7,683.84	10/27/1998	Exploratory	Terminated	6/1/2001
SIDEWINDER	Union Pacific Resources Co.	63,913.82	9/3/1999	Exploratory	Terminated	10/17/2000
KINNEY RIM	Stone Energy LLC	8,624.85	10/8/1999	Exploratory	Terminated	8/4/2000
FESTUS	Yates Pet. Corp.	24,936.17	5/17/2001	Exploratory	Terminated	10/12/2001
SOFIA	Yates Pet. Corp.	17,942.48	10/29/2001	Exploratory	Invalid, ab initio	10/29/2001
ANTELOPE WASH	Anadarko Explor. & Prod. Co. LP	13,263.64	11/14/2001	Exploratory	Terminated	2/20/2004
WHALEN BUTTE	Anadarko Pet. Corp.	9,676.79	11/21/2001	Exploratory	Invalid, ab initio	6/3/2003
CHURCHILL (Deep)	Anadarko Explor. & Prod. Co. LP	28,352.19	10/1/2002	Exploratory	Terminated	9/8/2006
MERLIN	Yates Pet. Corp.	14,034.98	11/26/2002	Exploratory	Terminated	4/14/2004
CEDAR MOUNTAIN	Barlow & Haun, Inc.	8,906.00	12/26/2002	Exploratory	Terminated	7/26/2003
HOT DOG HILL (Shallow)	Tom Brown, Inc.	3,862.74	5/8/2003	Exploratory	Terminated	4/9/2004

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
KITT PEAK	Yates Pet. Corp.	16,432.35	7/24/2003	Exploratory	Invalid, ab initio	2/3/2004
HALE	Yates Pet. Corp.	21,828.16	8/26/2003	Exploratory	Terminated	9/30/2005
CROOKED WASH	Yates Pet. Corp.	24,895.37	8/29/2003	Exploratory	Terminated	6/30/2005
SOUTH DUG SPRINGS	Anadarko Explor. & Prod. Co. LP	17,211.35	9/19/2003	Exploratory	Terminated	9/27/2006
FORT LACLEDE	Anadarko Explor. & Prod. Co. LP	18,548.79	9/22/2003	Exploratory	Terminated	8/9/2004
YAZ	Yates Pet. Corp.	12,381.72	4/27/2004	Exploratory	Terminated	7/9/2006
HEALEY (Deep)	Questar Explor. & Prod. Co.	13,906.17	5/11/2004	Exploratory	Terminated	10/15/2006
WEST DRAW (Deep)	Samson Resources Co.	24,862.34	7/14/2004	Exploratory	Terminated	3/22/2006
ARECIBO	Yates Pet. Corp.	6,080.91	7/29/2004	Exploratory	Terminated	3/23/2007
WHALE	EOG Resources, Inc.	17,259.62	8/31/2004	Exploratory	Terminated	10/1/2007
SA UNIT	Encana Oil & Gas (USA), Inc.	23,303.15	9/22/2004	Exploratory	Terminated	3/18/2006
BUSH DRAW (Deep)	Yates Pet. Corp.	24,183.85	9/30/2004	Exploratory	Invalid, ab initio	9/30/2004
SPRINGBOK	Mak J Energy Wyoming, LLC	9,993.20	12/28/2004	Exploratory	Terminated	10/16/2006
FELLER	Yates Pet. Corp.	5,760.00	1/14/2005	Exploratory	Terminated	1/1/2007
CHICKEN RANCH	Kodiak Oil & Gas Corp.	9,001.59	4/29/2005	Exploratory	Terminated	7/23/2006
BUSHBUCK	Mak J Energy Wyoming, LLC	6,140.15	8/25/2005	Exploratory	Terminated	10/1/2006
NORTH LONETREE	East Resources, Inc.	24,912.60	9/2/2005	Exploratory	Terminated	9/2/2005
SPIKE	Questar Explor. & Prod. Co.	9,881.51	12/16/2005	Exploratory	Terminated	9/10/2006
MORDRED (Shallow)	Anadarko Explor. & Prod. Co. LP	12,751.31	8/24/2006	Exploratory	Terminated	9/17/2009
GUNSLINGER	SWEPI LP	36,847.80	12/15/2006	Exploratory	Terminated	9/4/2008
DELAWARE (Deep)	P&M Pet. Management, LLC	22,370.69	2/28/2007	Exploratory	Terminated	9/1/2009
FARSON CUTOFF	SWEPI LP	24,420.58	9/5/2007	Exploratory	Terminated	8/18/2008
SERRANO	Odyssey Explor., Inc.	20,987.17	11/30/2007	Exploratory	Invalid, ab initio	11/30/2007
SLICE	Orion Energy Partners	11,479.28	5/2/2008	Exploratory	Terminated	5/18/2009
COYOTE FLATS (Deep)	Devon Energy Prod. Co., LP	22,709.97	5/28/2008	Exploratory	Terminated	7/1/2010
TEAKETTLE	Encana Oil & Gas (USA), Inc.	19,290.32	6/6/2008	Exploratory	Cancelled	
MOUNTAIN LION	Davis Pet. Corp.	12,875.50	9/22/2008	Exploratory	Terminated	1/27/2009
MIRROR	Samson Resources Co.	5,938.36	12/17/2008	Exploratory	Terminated	5/27/2010
GOOSE	Yates Pet. Corp.	13,806.96	10/16/2009	Exploratory	Terminated	8/26/2010
AIRPORT	Samson Resources Co.	800.00	2/18/2011	Exploratory	Terminated	2/9/2012
LINWOOD	Continental Oil Co.	27,660.99		Exploratory	Withdrawn	3/12/1951
PRETTY WATER	Mountain Fuel Supply Co.			Exploratory	Cancelled	6/17/1952
HORSE SHOE CREEK	Mountain Fuel Supply Co.	9,010.23		Exploratory	Cancelled	2/2/1954
FISHER CREEK	Sun Oil Co.	12,718.49		Exploratory	Cancelled	2/7/1956
WEST TABLE ROCK	St. Helens Pet. Corp.	2,759.07		Exploratory	Denied	5/28/1958
GOTTSCHE RANCH	Mountain Fuel Supply Co.	5,154.60		Exploratory	Withdrawn	11/10/1958
MORMON FERRY	Trigood Oil Co.	10,853.20		Exploratory	Withdrawn	9/17/1959
GREASEWOOD FLAT	Pan American Pet. Corp.	35,149.11		Exploratory	Withdrawn	1/15/1960
BERTA AIRPORT	Continental Oil Co.	5,760.44		Exploratory	Withdrawn	5/20/1960
GREEN RIVER BASIN #1	GREEN RIVER BASUN CORP.	30,470.11		Exploratory	Withdrawn	3/7/1961
PACIFIC CREEK	G. L. Reasor	27513.58		Exploratory	Withdrawn	4/14/1961
RYE GRASS	Colorado Oil and Gas Corp.	66,864.37		Exploratory	Withdrawn	1/14/1963
SUBLETTE FLAT	Mountain Fuel Supply Co.	65,127.79		Exploratory	Withdrawn	10/12/1965
LEUCITE HILLS	Mountain Fuel Supply Co.	8,935.74		Exploratory	Withdrawn	5/10/1966
B R RANCH	MKM Explor. Co.	62,610.45		Exploratory	Withdrawn	3/3/1967
MEADOW SPRING DRAW	Mountain Fuel Supply Co.	18,553.25		Exploratory	Withdrawn	1/26/1968
FAIR	Davis Oil Co.			Exploratory	Cancelled	4/22/1980
OREGON BUTTES	Natural Resources Corp.			Exploratory	Cancelled	5/20/1980
JESSEN BUTTE	George G. Anderman	22,456.00		Exploratory	Cancelled	5/27/1980
FARSON	Wodds Pet. Corp.	12,790.46		Exploratory	Cancelled	9/26/1980
KINCH SPRINGS	Davis Oil Co.			Exploratory	Cancelled	10/3/1980
GREEN	Davis Oil Co.	15,612.46		Exploratory	Cancelled	10/21/1980
DAGGER	Davis Oil Co.	8,929.00		Exploratory	Cancelled	7/27/1981
ALINAM	Texaco Pet. Products	15,367.51		Exploratory	Cancelled	12/17/1981
LIGHTHOUSE	Davis Oil Co.	24,608.95		Exploratory	Cancelled	7/21/1982
PACKSADDLE CANYON	Moncrief Oil Interests	24,926.61		Exploratory	Cancelled	10/15/1982
MORRIS DRAW	Energetics, Inc.	3,786.76		Exploratory	Cancelled	1/18/1983
ATLANTIC CITY	American Quasar Pet. Co.	12,758.63		Exploratory	Cancelled	10/1/1983
CLAY BUTTES	Davis Oil Co.	18,399.65		Exploratory	Cancelled	2/3/1984
TRI-COUNTY	Exxon Co., USA	10,555.58		Exploratory	Cancelled	4/6/1984
OASIS WELL	Energetics Operating Co.	16,556.35		Exploratory	Cancelled	5/21/1984
CRAIGS DRAW	Belco Development Corp.	21,694.85		Exploratory	Cancelled	7/31/1984
ANDERSON RIDGE II	T.K. Kirk	19,164.05		Exploratory	Cancelled	10/30/1984
BUFFALO HUMP	Exxon Corp.	21,067.91		Exploratory	Cancelled	8/4/1986

Table 2. Unit cases closed within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	ACRES	EFFECTIVE DATE	UNIT TYPE	FINAL STATUS	CLOSED DATE
LONETREE	Farleigh Oil Properties	16,303.67		Exploratory	Cancelled	9/30/1987
BIG STAGE	Union Pacific Resources Co.	9,955.51		Exploratory	Cancelled	5/17/1988
SAXON HILL	Union Pacific Resources Co.	8,004.77		Exploratory	Cancelled	1/24/1989
ROE	Axem Resources, Inc.	4,729.50		Exploratory	Cancelled	1/1/1990
MASH	General Atlantic Rresources, Inc.	8,891.94		Exploratory	Cancelled	1/17/1991
SARATOGA	BTA Oil Producers	4,955.44		Exploratory	Withdrawn	9/20/1991
MANILA	Exxon Corp.	23,120.40		Exploratory	Cancelled	3/27/1992
RITA	Alpar Resources, Inc.	23,229.56		Exploratory	Cancelled	9/9/1992
MORMON KNOLLS	Atlantic Richfield Co.	26,067.58		Exploratory	Cancelled	2/22/1993
BLUE RIM	Presidio Oil Co.	24,821.12		Exploratory	Cancelled	12/19/1994
CHURCHILL	Union Pacific Resources Co.	13,076.57		Exploratory	Cancelled	7/21/1995
OVERLAND TRAIL	Presidio Oil Co.	14,007.22		Exploratory	Withdrawn?	1/1/1996
ORANGE BLOSSOM SPECIAL	Yates Pet. Corp.	16,577.44		Exploratory	Cancelled	9/4/1996
WEST 187	Barlow & Haun, Inc.	4,493.28		Exploratory	Withdrawn	11/1/1996
WIND RIVER MOUNTAINS	SMK Energy Corp.	15,948.62		Exploratory	Withdrawn	11/26/1996
WHITE ROCKS	Union Pacific Resources Co.	23,327.78		Exploratory	Withdrawn	11/26/1996
HAT	True Oil Co.	25,903.74		Exploratory	Cancelled	5/6/1997
RADIO TOWER	Ultra Pet. (USA), Inc.	26,038.36		Exploratory	Withdrawn	6/23/1997
NORTHERN LIGHTS	Yates Pet. Corp.	26,907.87		Exploratory	Withdrawn	11/3/1998
ORANGE BLOSSOM SPECIAL	Yates Pet. Corp.	17,878.58		Exploratory	Withdrawn	11/3/1998
JACK MORROW CREEK	Yates Pet. Corp.	24,920.66		Exploratory	Cancelled	6/9/1999
LOMBARD ROAD	Questar Explor. & Prod. Co.	22,587.23		Exploratory	Cancelled	9/27/2001
COBRA (Deep)	Anadarko Explor. & Prod. Co. LP	23,926.22		Exploratory	Cancelled	5/8/2003
LEGEND	Yates Pet. Corp.	15,980.29		Exploratory	Withdrawn	2/24/2004
KOUFAX	Yates Pet. Corp.	24,467.19		Exploratory	Cancelled	5/17/2004
VAQUERO	Yates Pet. Corp.	6,037.91		Exploratory	Withdrawn	9/9/2004
LONG HILL	Anadarko Explor. & Prod. Co. LP	15,083.97		Exploratory	Cancelled	8/11/2005
BLACK DIAMOND (Shallow)	XTO Energy, Inc.	15,601.32		Exploratory	Withdrawn	12/17/2007
EDEN VALLEY	Grynberg Pet. Co.	31,030.26		Exploratory	Withdrawn	5/8/2008
MANUEL GAP	Anadarko Explor. & Prod. Co. LP	10,028.70		Exploratory	Cancelled	11/14/2008
WILD HARE	Questar Explor. & Prod. Co.	10,291.36		Exploratory	Cancelled	5/5/2009
PAREA BUTTE	Apache Explor. Corp.	13,440.00		Exploratory	Withdrawn?	
FARSON ROAD	CIG Explor., Inc.	23,680.00		Exploratory	Withdrawn?	
SUBLETTE'S FLAT II	Davis Oil Co.	24,960.00		Exploratory	Withdrawn?	
TWELVEMILE KNOLL	Davis Oil Co.	24,320.00		Exploratory	Withdrawn?	
MEGAS	Forest Oil Corp.	25,450.64		Exploratory	Withdrawn	
BIG SANDY RIVER	Gas Resources Associates	30,720.00		Exploratory	Withdrawn?	
REED RESERVOIR	Jonah Oil Co. LLC	25,097.01		Exploratory	Withdrawn	
BUCKHORN DRAW	Moncrief Oil Interests	24,584.39		Exploratory	Withdrawn	
MIDDLE BAXTER BASIN	Mountain Fuel Supply Co.			Exploratory	Terminated?	
BITTER CREEK	Sierra Trading Corp.	33,920.00		Exploratory	Withdrawn?	
SHIPROCK	Signal Explor., Inc.	2,560.00		Exploratory	Terminated?	
LINWOOD	Sinclair Oi & Gas Co.	17,338.16		Exploratory	Withdrawn	
WHITE FEATHER	Sun Explor. & Prod. Co.	14,066.85		Exploratory	Cancelled	
RED WASH	Union Pacific Resources Co.	10,583.56		Exploratory	Withdrawn?	
LOMBARD CANYON	W. A. Moncrief	18,744.82		Exploratory	Withdrawn	

Table 3a. Active units within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	EFFECTIVE DATE	UNIT TYPE	ORIGINAL ACRES	CONTRACTED	PRESENT ACRES
CANYON CREEK DOME;	WEXPRO COMPANY	12/18/1937	GAS	15,444.87	YES	14,505.39
CLAY BASIN;	WEXPRO COMPANY	12/27/1939	GAS	11,116.83	NO	553.47
SOUTH BAXTER BASIN;	WEXPRO COMPANY	11/1/1942	GAS	38,769.69	NO	38,769.69
CHURCH BUTTES;	WEXPRO COMPANY	8/17/1944	GAS	49,848.07	NO	49,848.07
TABLE ROCK;	CHEVRON USA, INCORPORATED	10/1/1945	OIL	12,691.50	NO	12,691.50
SALT WELLS;	SAMSON RESOURCES COMPANY	6/21/1949	GAS	7,550.00	YES	668.92
EAST LABARGE;	EOG RESOURCES, INCORPORATED	4/6/1951	GAS	15,354.29	YES	5,581.15
DESERT SPRINGS;	BLACK DIAMOND MINERALS, LLC	10/30/1957	GAS	28,360.00	YES	14,397.03
TRAIL;	WEXPRO COMPANY	5/14/1958	GAS	10,431.71	YES	6,755.10
GREEN RIVER BEND;	EOG RESOURCES, INCORPORATED	6/16/1958	OIL	23,806.92	YES	15,025.00
ARCH;	ANADARKO PETROLEUM CORPORATION	2/26/1959	GAS	22,198.75	YES	12,565.30
FIGURE FOUR CANYON;	EOG RESOURCES, INCORPORATED	6/8/1959	GAS	8,319.35	YES	1,280.00
PLAYA;	BLACK DIAMOND MINERALS, LLC	3/22/1960	GAS	22,538.10	YES	4,105.33
JACKKNIFE SPRING;	MERIT ENERGY COMPANY	9/2/1960	GAS	19,776.32	YES	1,490.11
JOYCE CREEK;	CROWN O&G COMPANY	4/24/1962	GAS	2,917.02	YES	1,284.43
NITCHIE GULCH;	WHITING OIL & GAS CORPORATION	10/1/1962	GAS	7,474.38	YES	5,960.24
PINE CANYON;	SAMSON RESOURCES COMPANY	12/19/1963	GAS	12,901.23	YES	1,400.43
MONELL;	ANADARKO PETROLEUM CORPORATION	12/1/1964	SECONDARY	10,120.27	NO	10,120.27
LEUCITE HILLS;	WEXPRO COMPANY	7/25/1969	GAS	8,935.74	YES	1,280.00
BUTCHER KNIFE SPRING;	WEXPRO COMPANY	7/20/1971	GAS	31,532.48	YES	2,195.65
BRADY DEEP;	MERIT ENERGY COMPANY	10/18/1972	GAS	39,012.25	YES	5,975.61
KINNEY;	WEXPRO COMPANY	6/5/1973	GAS	21,218.04	YES	2,471.21
BITTER CREEK II;	BP AMERICA INCORPORATED	12/12/1973	GAS	18,532.70	YES	360.00
HIGGINS;	MERIT ENERGY COMPANY	3/22/1974	GAS	21,531.33	YES	4,840.00
FONTENELLE II;	XTO ENERGY INCORPOARATED	7/30/1974	GAS	41,809.57	YES	13,061.76
HAY RESERVOIR;	ENCANA OIL & GAS (USA), INCORPORATED	12/24/1975	GAS	28,909.40	YES	21,441.91
STEAD CANYON;	EOG RESOURCES, INCORPORATED	3/29/1977	GAS	9,779.23	YES	1,362.68
MONUMENT BUTTE IV;	CROWN ENERGY PARTNERS, LLC	3/27/1978	GAS	24,337.24	YES	7,084.15
STEAMBOAT MOUNTAIN;	BLACK JACK OIL, INCORPORATED	4/18/1978	GAS	14,132.24	YES	635.44
HIAWATHA (DEEP);	WEXPRO COMPANY	10/30/1978	GAS	16,062.75	NO	1,843.67
LITTLE MONUMENT II;	CAERUS NORTHERN ROCKIES, LLC	1/26/1979	GAS	8,960.00	YES	2,680.00
EMIGRANT TRAIL;	BP AMERICA INCORPORATED	8/30/1979	OIL	42,226.95	YES	600.00
RIM ROCK;	BLACK JACK OIL, INCORPORATED	2/29/1980	GAS	24,816.10	YES	640.00
HENRY;	BREITBURN OPERATING, L.P.	4/30/1980	GAS	13,415.89	YES	5,954.41
BUCCANEER;	SAGE PETROLEUM CORPORATION	12/16/1980	GAS	12,120.00	YES	680.00
BLUE FOREST;	BREITBURN OPERATING, L.P.	12/13/1982	GAS	37,756.85	YES	9,716.53
WEST SWAN;	CHEVRON USA, INCORPORATED	11/28/1983	GAS	2,866.29	YES	874.02
SOUTH HENRY;	BREITBURN OPERATING, L.P.	9/4/1984	GAS	4,481.94	YES	1,160.57
LUCKEY DITCH;	WHITING OIL & GAS CORPORATION	11/16/1984	OIL	7,370.47	YES	5,812.44
TAYLOR RANCH;	WHITING OIL & GAS CORPORATION	5/8/1985	GAS	15,996.16	YES	1,840.00
RAPTOR;	XTO ENERGY, INCORPORATED	5/31/1985	GAS	18,786.39	YES	2,416.08
RATTLESNAKE;	BREITBURN OPERATING, L.P.	1/31/1991	GAS	2,240.00	YES	480.00

Table 3a. Active units within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	EFFECTIVE DATE	UNIT TYPE	ORIGINAL ACRES	CONTRACTED	PRESENT ACRES
HENRY ENHANCED;	BREITBURN OPERATING, L.P.	4/1/1992	SECONDARY	7829.81	NO	7,829.81
HAVEN;	CROWN ENERGY PARTNERS, LLC	5/11/1993	GAS	13,245.13	YES	3,561.28
STAGECOACH DRAW;	CHEVRON USA, INCORPORATED	5/24/1993	GAS	23,574.68	YES	3,864.12
HORSESHOE;	BREITBURN OPERATING, L.P.	7/30/1993	GAS	22,199.16	YES	1,469.16
BRAVO;	YATES PETROLEUM CORPORATION	10/21/1993	GAS	3,720.36	YES	2,200.36
LODGEPOLE (SHALLOW);	CROWN ENERGY PARTNERS, LLC	6/3/1994	GAS	23,086.97	YES	320.00
CABRITO;	BP AMERICA INCORPORATED	9/25/1996	GAS	8,329.68	YES	2,367.90
SOUTH BRADY(SHALLOW);	MERIT ENERGY COMPANY	11/10/1997	GAS	3,605.32	YES	280.00
HACIENDA;	ENCANA OIL & GAS (USA), INCORPORATED	2/28/2001	EXPLORATORY	21,108.34	NO	21,108.34
LANEY RIM;	ANADARKO PETROLEUM CORPORATION	12/13/2001	GAS	20,298.44	YES	160.00
SAG (SHALLOW);	ENCANA OIL & GAS (USA), INCORPORATED	10/7/2003	GAS	4,840.46	YES	240.00
ALKALI GULCH	QEP ENERGY COMPANY	10/27/2004	EXPLORATORY	24,707.25	NO	24,707.25
HORSESHOE BASIN;	DEVON ENERGY PRODUCTION COMPANY, LP	4/29/2005	EXPLORATORY	24,983.66	NO	24,983.66
WHISKEY CANYON	QEP ENERGY COMPANY	1/12/2006	EXPLORATORY	14,729.45	NO	14,729.45
CRIMSON;	ENCANA OIL & GAS (USA), INCORPORATED	3/30/2006	EXPLORATORY	23,650.35	NO	23,650.35
PUMA (DEEP)	W. A. MONCRIEF JR.	4/20/2006	GAS	18,195.75	YES	18,195.75
EDEN RANCH;	GRYNBERG PETROLEUM COMPANY	5/21/2008	EXPLORATORY	12,572.38	NO	12,572.38
RUBICON;	DEVON ENERGY PRODUCTION COMPANY, LP	6/30/2008	EXPLORATORY	40,035.45	NO	40,035.45
DESOLATION ROAD;	SAMSON RESOURCES COMPANY	12/22/2008	EXPLORATORY	24,961.57	NO	24,961.57
BRIDGER RENDEZVOUS (DEEP);	WESTERN AMERICAN RESOURCES, LLC	9/28/2010	EXPLORATORY	25,012.64	NO	25,012.64
BUCK BASIN (DEEP);	WESTERN AMERICAN RESOURCES, LLC	2/28/2011	EXPLORATORY	25,108.70	NO	25,108.70
			TOTAL ACRES	**1,172,244.86**	**TOTAL ACRES**	**569,765.73**

Table 3b. Active units, their township and range locations, and initial well requirements within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	TOWNSHIPS	RANGES	INITIAL WELL REQUIREMENTS
CANYON CREEK DOME;	12 & 13N	100 & 101W	5,000'
CLAY BASIN;	WY/12N; AND UT/3N	WY/105W; AND UT/24E	
SOUTH BAXTER BASIN;	15N; 16N; 17N; AND 18N	104 & 105W; 104W; 103 & 104W; AND 103 & 104W	NO WELL REQUIRED
CHURCH BUTTES;	15 & 16N; AND 17N	112 & 113W; AND 111, 112, & 113W	NO MINIMUM DEPTH SPECIFIED
TABLE ROCK;	18 & 19N	97 & 98W	PENETRATE WASATCH/4,000'
SALT WELLS;	14N	102 & 103W	NUGGET/6,300'
EAST LABARGE;	26 & 27N	112W	DAKOTA/10,000'
DESERT SPRINGS;	20 & 21N	97 & 98W	UPPER 1,000' MESAVERDE/6,500'
TRAIL;	13 & 14N	100W	MESAVERDE/7,600'
GREEN RIVER BEND;	26 & 27N; AND 28N	112 & 113W; AND 112W	2ND FRONTIER/7,600'
ARCH;	19N	98 & 99W	TOP 100 OF ERICSON/6,500'
FIGURE FOUR CANYON;	27N	112W	2ND FRONTIER/8,000'
PLAYA;	20 & 21N	98 & 99W	NO WELL REQUIRED
JACKKNIFE SPRING;	16N; AND 17N	100, 100 1/2, & 101W; AND 100 & 101W	100' BELOW TOP OF BAXTER/6,100'
JOYCE CREEK;	15N	103 & 104W	NO WELL REQUIRED
NITCHIE GULCH;	23N	103W	NO WELL REQUIRED
PINE CANYON;	22 & 23N	103 & 104W	DAKOTA/8,700'
MONELL;	18 AND 19N	98 AND 99W	
LEUCITE HILLS;	22N	103 & 104W	DAKOTA/7,500'
BUTCHER KNIFE SPRING;	13N; 14N; AND 15N	113W; 112 & 113W; AND 113W	MORRISON/13,200'
BRADY DEEP;	15N; 16N; 17N; AND 18N	101W; 100 & 101W; 100 & 101W; AND 100W	MADISON/15,300'
KINNEY;	12, 13, & 14N	99 & 100W	NUGGET/15,200'
BITTER CREEK II;	15N; AND 16N	99W; AND 98 & 99W	TOP 200' OF NUGGET/20,200'
HIGGINS;	17N AND 18N	98 & 99W; AND 98W	100' BELOW TOP OF NUGGET/15,500'
FONTENELLE II;	25 & 26N	111, 112, & 113W	THROUGH BEAR RIVER/10,900'
HAY RESERVOIR;	23 & 24N	96 & 97W	800' BELOW TOP OF MESAVERDE/10,900'
STEAD CANYON;	26 27N	112W	UPPER 350' OF 2ND FRONTIER/8,000'
MONUMENT BUTTE IV;	25 & 26N	110W	ENTIRE 2ND FRONTIER/11,000'
STEAMBOAT MOUNTAIN;	23 & 24N	102W	400' BELOW TOP OF FRONTIER/11,700'
HIAWATHA (DEEP);	WY/12N; AND CO/12N	WY/99 & 100W; AND CO/99 & 100W	
LITTLE MONUMENT II;	25N	111W	400' OF 2ND FRONTIER/9,800'
EMIGRANT TRAIL;	16N; 17N; AND 18N	96 & 97W; 95 & 96W; AND 95 & 96W	UPPER 550' OF MESAVERDE/12,700'
RIM ROCK;	24N; AND 25N	103W; AND 102 & 103W	UPPER 400' OF FRONTIER/11,900'
HENRY;	13 & 14N	113 & 114W	100' BELOW TOP OF DAKOTA/13,600'
BUCCANEER;	26N	102W	UPPER 200' OF HILLIARD/13,000'
BLUE FOREST;	24 & 25N	109, 110, & 111W	UPPER 50' OF ASPEN
WEST SWAN;	25N	111 & 112W	UPPER 345' OF 2ND FRONTIER/4,000'
SOUTH HENRY;	13N	113W	UPPER 150' OF MORRISON/14,200'
LUCKEY DITCH;	12N	114W	UPPER 25' OF MORRISON/15,750'
TAYLOR RANCH;	12 & 13N	113 & 114W	UPPER 50' OF MORRISON/14,350'
RAPTOR;	24N; AND 25N	111 & 112W; AND 112W	UPPER 100' OF 2ND FRONTIER/9,800'
RATTLESNAKE;	24N	111W	UPPER 100' OF DAKOTA/11,174'

Table 3b. Active units, their township and range locations, and initial well requirements within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	TOWNSHIPS	RANGES	INITIAL WELL REQUIREMENTS
HENRY ENHANCED;	13 & 14N	113W	
HAVEN;	23N	111W	UPPER 200' OF DAKOTA/11,639'
STAGECOACH DRAW;	22, 23, & 24N	107 & 108W	100' BELOW TOP OF ALMOND B2 SAND/8,100'
HORSESHOE;	23 & 24N	109 & 110W	400' BELOW TOP OF DAKOTA/11,800'
BRAVO;	23N	99W	UPPER 600' OF LEWIS/6,900'
LODGEPOLE (SHALLOW);	24N; AND 25N	109 & 110W; 109W	200' BELOW TOP OF MUDDY/11,920'
CABRITO;	29N	107 & 108W	1,000' BELOW BASE FORT UNION/9,500'
SOUTH BRADY(SHALLOW);	16 & 17N	101W	900' BELOW TOP OF BLAIR/6,625'
HACIENDA;	28N	107 & 108W	2,000' BELOW TOP OF LANCE/10,500'
LANEY RIM;	17N; AND 18N	96 & 97W; AND 97W	300' BELOW TOP OF ALMOND/10,800'
SAG (SHALLOW);	29N	107W	100' BELOW TOP OF MESAVERDE/13,000'
ALKALI GULCH	12N; AND 13N	99, 100, & 101W; AND 100W	500' BELOW TOP OF NUGGET/14,700'
HORSESHOE BASIN;	12-13N	102-103W	50' BELOW TOP OF CANYON CREEK MEMBER OF ERICSON/5,980'
WHISKEY CANYON	12N; AND 13N	101-102W; AND 101W	DAKOTA/13,911'
CRIMSON;	27-28N	108-109W	200' BELOW TOP OF MESAVERDE/9,400'
PUMA (DEEP)	14 & 15N	111 & 112W	50' BELOW BASE OF ERICSON/10,100'
EDEN RANCH;	27 & 28N	105 & 106W	850' BELOW TOP OF MESAVERDE/14,000'
RUBICON;	13N; 14N; AND 15N	106W; 105 & 106W; AND 105W	100' BELOW TOP OF FRONTIER/16,000'
DESOLATION ROAD;	15N AND 16N	97 & 98W; AND 95, 96, 97, & 98W	1,100' BELOW TOP OF "CHEROKEE INTERVAL" OF FORT UNION/10,500'
BRIDGER RENDEZVOUS (DEEP);	14 & 15N	110 & 111W	50' BELOW TOP OF ROCK SPRINGS/10,350'
BUCK BASIN (DEEP);	14N AND 15N	111& 112W; AND 112W	50' BELOW TOP OF ROCK SPRINGS/11,050'

Table 4. Active and closed coalbed natural gas units within the Rock Springs Planning Area. Data from Bureau files.

UNIT NAME	OPERATOR NAME	CASE ACRES	EFFECTIVE DATE	FINAL STATUS	CLOSED DATE	TOWNSHIPS	RANGES	INITIAL WELL REQUIREMENTS
Greasewood Wash	Barrett Resources Corp.	21,841.84	12/22/1999	Terminated	12/22/2001	22 & 23N	101 & 102W	6 wells: 50' below base of Rock Springs of type log/5,000'
Rifes Rim	Warren E & P, Inc.	12,471.00	9/26/2002	Terminated	3/6/2007	14N	101W	2 wells: 100' below base of Almond/2,200' & 3,800'
Copper Ridge	Anadarko Pet. Corp.	24,890.83	12/24/2002	Terminated	12/22/2011	16N; AND 17N	100, 100&1/2, & 101W; AND 100 & 101W	5 wells: 50' below top of Almond of type log
North Copper Ridge	Anadarko Pet. Corp.	24,408.04	1/7/2003	Terminated	12/22/2011	16N; 17N; AND 18N	100W; 100 & 101W; AND 100W	5 wells: 50' below top of Almond of type log/3,020'
Found Valley	Yates Petroleum Corp.	24,960.03	7/17/2003	Invalid, Ab Initio	7/17/2003	25N	99 & 100W	5 wells: 50' below top of Lance Shale marker of type log
Lost Valley	Yates Petroleum Corp.	24,036.44	7/21/2003	Invalid, Ab Initio	7/21/2003	25N	100 & 101W	5 wells: 50' below top of Lance Shale marker of type log
Pacific Isle	Warren E & P, Inc.	19,706.50	9/5/2003	Terminated	9/5/2006	14 & 15N	101 & 102W	5 wells: 100' below top of Ericson of type log
Chicken Springs	Warren E & P, Inc.	19,779.55	7/30/2004	Active		13 & 14N	100 & 101W	5 wells: 650' below top of Almond of type log
Hi-Line	Yates Petroleum Corp.	24,544.77	9/9/2004	Terminated	9/1/2008	24N; AND 25N	98 & 99W; AND 98W	5 wells: 50' below base of deepest Fort Union coal of type log
Maravich	Yates Petroleum Corp.	24,018.12	10/29/2004	Invalid, Ab Initio	10/29/2004	20N; AND 21N	97 & 98W; AND 96 & 97W	5 wells: to base of Fort Union coal of type log
Azurite	El Paso Prod. O&G Co.	24,752.23	4/8/2005	Invalid, Ab Initio	4/8/2005	13 & 14N	103 & 104W	5 wells: 50' below base of lowest coal in mid-Almond coal zone of type log
West Wind	Arco O&G Co.	22,898.63		Cancelled	7/23/1992	22 & 23N	108W	100' below coal zone in upper Lance/6,450'
East Wind	Arco O&G Co.	5,503.78		Cancelled	7/23/1992	22N	106W	75' below coal zone in upper Lance/6,800'
Wind Break	Arco O&G Co.	8,978.80		Cancelled	7/23/1992	23N	107W	80' below coal zone in upper Lance/6,550'
Magic	Yates Petroleum Corp.	17,590.20		Withdrawn	2/24/2004	20N	96 & 97W	4 wells: 50' below base of Fort Union coal bed #2 of type log
Maris	Yates Petroleum Corp.	16,027.83		Withdrawn	3/31/2005	20 & 21N	100W	Mesaverde coal
	Total Acres	**316,408.59**						

Table 5. Rock Spring Planning Area 2011 field production (Wyoming Oil and Gas Conservation Commission, 2012).

FIELD	OIL (BARRELS)	GAS (THOUSAND CUBIC FEET)	WATER (BARRELS)
AIRPORT	0	10,379	0
ANTELOPE	3	266,213	159
ARCH	14,174	235,128	955
BAXTER BASIN MIDDLE	0	14,870	0
BAXTER BASIN NORTH	161	134,803	666
BAXTER BASIN SOUTH	33	115,016	69
BAXTER SIDING	0	0	0
BIRD CANYON	6,256	2,436,997	26,613
BITTER CREEK	1,758	158,297	3,963
BLACK BUTTE CREEK	0	223	0
BLUE FOREST	7,093	2,101,563	19,068
BRADY	112,814	1,902,732	3,420,092
BUCCANEER	0	74,736	0
BUCKHORN CANYON	1,209	40,940	357
BUTCHER KNIFE SPRINGS	1,977	319,451	17,539
CANYON CREEK	56,013	9,603,231	149,228
CROOKED CANYON	783	658,589	3,107
DEADMAN WASH	0	149,651	667
DELANEY RIM	0	0	0
DESERT FLATS	3,144	70,359	6,176
DESERT SPRINGS	1,649	1,676,284	1,931
DESERT SPRINGS WEST	6,233	94,978	401
EMIGRANT TRAIL	2,270	113,398	6,834
ESSEX MOUNTAIN	0	22,909	240
FIGURE FOUR CANYON	207	365,750	5,515
FILLMORE	14,692	530,211	14,849
FONTENELLE	13,248	9,976,006	124,354
FOUR MILE GULCH	2,436	317,969	4,400
HANSEN DRAW	79	7,872	443
HAPPY SPRINGS	10,081	38,024	101,025
HATFIELD	3,469	2,522	1,763
HAY RESERVOIR	28,333	3,283,680	41,067
HENRY	19,483	606,013	4,807
HENRY SOUTH	6,004	34,185	803
HIAWATHA	897	774,820	2,532
HIGGINS	117	71,425	486
HORN CANYON	107	16,883	191
IRON PIPE	812	36,404	1,761
JADE	1,688	106,770	4,166
JAMES CREEK	0	12,958	0
JEFFERSON	0	6,085	0
JONAH	2,720,128	305,466,983	4,544,266
JOYCE CREEK	231	24,457	0
KINNEY	215	1,084,547	29,661

Table 5. Rock Spring Planning Area 2011 field production (Wyoming Oil and Gas Conservation Commission, 2012).

FIELD	OIL (BARRELS)	GAS (THOUSAND CUBIC FEET)	WATER (BARRELS)
LABARGE	78,695	6,221,571	480,482
LANEY WASH	1,405	198,499	8,137
LEUCITE HILLS	637	1,945,471	2,434
LINCOLN ROAD	17,237	3,329,757	46,060
LITTLE MONUMENT	3,044	838,449	1,707
LOOKOUT WASH	4,752	1,102,451	9,052
MASTERSON	0	40,685	81
MESA	6,928	2,098,218	30,565
MIDDLE MOUNTAIN	64	4,944	0
MONUMENT BUTTE	986	179,462	4,382
NITCHIE GULCH	679	676,422	3,897
PATRICK DRAW	1,586,675	922,014	2,257,583
PATRICK DRAW NORTH	7,116	6,551	0
PINE CANYON	232	739,698	5,428
PINEDALE	4,110,772	555,793,147	19,021,927
PLAYA	20	1,586	24
POINT OF ROCKS	0	694,758	3,170
POTTER MOUNTAIN	0	0	0
RED LAKE	1,192	28,701	17,193
REISER CANYON	0	0	0
RIM ROCK	0	75,185	0
ROBIN	768	701,762	99,110
SALT WELLS	0	120,416	61
SHEEP CAMP	319	77,903	3,251
SINKHOLE	533	27,260	251
SIXMILE SPRING	0	26,664	21
SPUR CREEK	9	19,525	597
STAGE STOP	1,731	48,579	283
STAGECOACH DRAW	4,088	400,859	1,404
STEAD CANYON	6,048	1,500,713	8,009
STEAMBOAT MOUNTAIN	0	930	0
STORM SHELTER	3,263	259,361	4,786
SUBLETTE FLATS	0	0	0
SUGARLOAF BUTTE	1,543	2,127	1,107
SWAN	6,867	453,082	4,130
TABLE ROCK	39,280	9,042,334	127,071
TABLE ROCK SOUTHWEST	224	217,963	0
TAYLOR RANCH	139	0	651
TEN MILE DRAW	0	20,961	0
TIMBER ROCK	1,097	51,647	770
TRAIL UNIT	46,277	10,973,527	239,271
TREASURE	0	3,718	0
TWIN ROCKS	1	4,842	0
WC	160,879	27,274,886	60,604,416
WIND DANCER	1,584	1,219,330	28,877

Table 6a.

Direct Rocky Mountain annual operating costs for an average oil well in current dollars. Data from Energy Information Administration (2010).

Producing Depth	2006	2007	2008	2009
8,000 feet	33,960	38,880	41,470	39,420
12,000 feet	47,410	53,530	56,780	55,530

Table 6b.

Direct Rocky Mountain annual operating costs for an average gas well in current dollars. Data from Energy Information Administration (2010).

Producing Depth	2006	2007	2008	2009
8,000 feet				
250,000 cubic feet per day	52,200	64,700	68,700	65,200
500,000 cubic feet per day	40,600	52,700	54,800	52,400
12,000 feet				
250,000 cubic feet per day	64,300	78,100	83,000	78,900
500,000 cubic feet per day	49,100	61,800	64,600	61,800

Table 7. Active water disposal wells in Rock Springs Planning Area. Data from Wyoming Oil and Gas Conservation Commission (2012).

FIELD	WELL NAME	LOCATION	FORMATION	DATE	OPERATOR
FONTENELLE	#41-35 FEDERAL	NENE 35-26N-112W	ALMY	1994	XTO ENERGY INC
FONTENELLE	#14-25D FEDERAL	SWSW 25-26N-112W	ALMY	2002	XTO ENERGY INC
JONAH	#4-1 HACIENDA	NWSW 1-28N-108W	LOWER FORT UNION	2004-2012	ENCANA OIL & GAS (USA) INC
JONAH	#59-36 STUD HORSE BUTTE	NESW 36-29N-108W	FORT UNION	2008	ENCANA OIL & GAS (USA) INC
JONAH	8-31 WDW	SE NE 31-29N-107W	LOWER FORT UNION	2009	ENCANA OIL & GAS (USA) INC
BRADY	#1 UNIT	NWSE 13-16N-101W	MESAVERDE	1974	MERIT ENERGY COMPANY
BRADY	#2 UNIT	NWSE 35-17N-101W	MESAVERDE	1979	MERIT ENERGY COMPANY
BRADY	#3 UNIT	NENE 17-17N-100W	MESAVERDE	1987	MERIT ENERGY COMPANY
BRADY	#1-9 UPRR	SESW 9-17N-100W	NUGGET	1993	MERIT ENERGY COMPANY
JOYCE CREEK	#23-8A UNIT	NESW 8-15N-103W	1ST DAKOTA	1975	CROWN OIL & GAS
PATRICK DRAW	1-11-18-100 PIPELINE	NENW 1-18N-100W	FOX HILLS	2001	OMIMEX PETROLEUM INC
PATRICK DRAW	#13-11-18-100	NE 13-18N-100W	FOX HILLS	2002	OMIMEX PETROLEUM INC
PATRICK DRAW	179 MONELL SWD	SWNW 34-19N-99W	FOX HILLS	2009	ANADARKO E&P CO LP CO
PATRICK DRAW	54-33 MONELL UNIT	NESE 33-19N-99W	FOX HILLS	2010	ANADARKO E&P CO LP CO
TABLE ROCK	#23-2 TABLE ROCK UNIT	SWNE 23-19N-98W	ERICSON	2004	CHEVRON USA
TRAIL	#1 TRAIL UNIT	NWSE 16-13N-100W	FOX HILLS & LANCE	2011	WEXPRO COMPANY
UNNAMED	#2 UPRC-1	CSW 1-22N-102W	ROCK SPRINGS	1997	ANADARKO E & P CO LP
UNNAMED	#4-1 UPRC-GREASEWOOD WASH	NWNW 1-22N-102W	NUGGET-BLAIR	2000-2005	ANADARKO E & P CO LP
UNNAMED	35-1-2I UPR	SWNE 35-23N-102W	BLAIR	2005	ANADARKO E & P CO LP
UNNAMED	#15101-31I FED	SWNE 31-15N-101W	ROCK SPRINGS & LANCE	DEQ	LEGEND SERVICES INC
UNNAMED	#01BR 21-24-98I	NENE 21-24N-98W	FORT UNION & LANCE	2002/2003/2005	SUMMIT GAS RESOURCES INC
UNNAMED	#9 HI LINE UNIT	SWNE 22-24N-99W	L FORT UNION & LANCE	2005	YATES PETROLEUM CORP

Table 8

U.S. Geological Survey 2002 assessment of undiscovered conventional accumulation assessment units in the Southwestern Wyoming Province, Rock Springs Planning Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Assessment Unit Name	**Exploration Status**	**Number Range**	**Mean Size (MMBO)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (US Survey Feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (US Survey Feet)**
Sub-Cretaceous	Established	2-8	2.0	36	1,768-13,763	5-45	20.0	3,022-20,013
Mowry	Established	1-7	1.5	38	11,975-15,994	3-22	12.0	2,133-19,029
Hilliard-Baxter-Mancos	Frontier	0	N/A	N/A	N/A	1-4	6.0	984-7,874
Mesaverde	Established	1-3	1.0	43	2,890-5,066	2-12	6.0	4,331-6,654
Measaverde-Lance-Fort Union	Frontier	1-3	1.0	41.5	984-5,905	2-40	10.0	1,969-8,858
Lewis	Frontier	0	N/A	N/A	N/A	8-31	8.0	2,822-8,501
Lance-Fort Union	Frontier	0	N/A	N/A	N/A	2-75	7.0	984-8,202

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

N/A = Not Available

Data from Kirschbaum et al. (2002)

Established = greater than 13 accumulations

Frontier = one to 13 accumulations

Hypothetical = no accumulations

Table 9.

U.S. Geological Survey 2002 assessment of undiscovered continuous accumulation assessment units in the Southwestern Wyoming Province, Rock Springs Planning Area.

Assessment Unit Name	Exploration Status	Median Assessment Unit Size (acres)	Median Cell Size (acres)	Tested Cells	Median Untested Cell Total (%)	Median Untested Cells With Potential to Add Reserves (%)	Median Carbon-dioxide Content (%)	Drilling Depth Range (US Survey Feet)
Mowry Gas	Established	11,458,000	120	3,193	96.0	9	1.0	6,890-17,060
Niobrara Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hilliard-Baxter-Mancos Gas	Established	10,506,000	80	157	99.9	14	0.4	6,890-15,092
Almond Gas	Established	3,353,000	160	1,790	91.0	52	2.3	7,546-19,029
Rock Springs-Ericson Gas	Established	4,361,000	80	290	99.4	48	2.3	7,546-19,357
Mesaverde Coal-Bed Gas (Mesaverde TPS)	Frontier	2,985,000	120	50	99.8	10	6.7	492-5,906
Mesaverde-Lance-Fort Union Gas	Established	3,482,000	100	454	98.6	24	0.8	8,005-17,060
Mesaverde Coal-Bed Gas (Mesaverde-Lance-Fort Union TPS)	Hypothetical	327,000	120	0	100.0	10	6.7	492-5,906
Fort Union Coal-Bed Gas (Mesaverde-Lance-Fort Union TPS)	Hypothetical	1,185,000	80	0	100.0	4	5.4	3,937-6,004
Lewis Gas	Established	3,310,000	100	539	98.3	18	0.9	5,700-18,701
Lance-Fort Union Gas	Established	2,444,000	80	110	99.6	25	0.5	5,000-16,404
Lance Coal-Bed Gas	Hypothetical	2,351,000	80	0	100.0	3	5.0	492-5,906
Fort Union Coal-Bed Gas (Lance-Fort Union TPS)	Hypothetical	3,047,000	80	3	100.0	10	5.0	492-5,906
Wasatch-Green River Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wasatch-Green River Coal-Bed Gas	Hypothetical	665,000	80	0	100.0	6	5.0	197-1,312

Cell = A volume having areal dimensions related to the drainage area of an individual well.

Established = greater than 24 cells

Frontier = one to 24 cells

Hypothetical = no cells

N/A = Not Available or Not Assessed

Data from Kirschbaum et al., 2002

Table 10.

U.S. Geological Survey 2002 assessment of undiscovered conventional and continuous resource assessment units within the Southwestern Wyoming Province, Rock Springs Planning Area.

			Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Southwestern Wyoming Province										Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Rock Springs Planning Area [1]								
			Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Assessment Unit Name	Type	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	Percent of Assessment Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Conventional Resources	Sub-Cretaceous	Oil	3.80	43.60	16.60	6.70	85.90	32.20	0.20	3.20	1.20	94.97%	3.61	41.41	15.76	6.36	81.58	30.58	0.19	3.04	1.14
		Gas				206.20	3,480.00	1,350.70	5.90	107.20	40.60	94.97%	0.00	0.00	0.00	195.82	3304.84	1282.71	5.60	101.80	38.56
	Mowry	Oil	1.70	14.80	6.60	2.70	25.90	11.20	0.30	3.70	1.60	94.97%	1.61	14.06	6.27	2.56	24.60	10.64	0.28	3.51	1.52
		Gas				85.80	301.40	195.10	1.60	6.70	3.90	94.97%	0.00	0.00	0.00	81.48	286.23	185.28	1.52	6.36	3.70
	Hilliard-Baxter-Mancos	Gas				4.60	31.90	15.50	0.30	2.10	1.00	37.31%	0.00	0.00	0.00	1.72	11.90	5.78	0.11	0.78	0.37
	Mesaverde	Oil	0.90	4.00	2.30	7.40	34.80	18.80	0.30	1.40	0.70	33.19%	0.30	1.33	0.76	2.46	11.55	6.24	0.10	0.46	0.23
		Gas				13.40	69.40	36.90	0.10	0.90	0.40	33.19%	0.00	0.00	0.00	4.45	23.03	12.25	0.03	0.30	0.13
	Measaverde-Lance-Fort Union	Oil	0.90	4.00	2.30	3.80	18.30	9.80	0.20	0.90	0.40	44.62%	0.40	1.78	1.03	1.70	8.17	4.37	0.09	0.40	0.18
		Gas				101.40	558.80	310.40	4.20	26.90	14.00	44.62%	0.00	0.00	0.00	45.25	249.35	138.51	1.87	12.00	6.25
	Lewis	Gas				103.70	304.00	194.60	3.70	13.30	7.80	26.51%	0.00	0.00	0.00	27.50	80.60	51.60	0.98	3.53	2.07
	Lance-Fort Union	Gas				75.00	465.90	245.60	0.70	5.00	2.50	37.97%	0.00	0.00	0.00	28.47	176.88	93.24	0.27	1.90	0.95
	Total Undiscovered Conventional Resource		**7.30**	**66.40**	**27.80**	**610.70**	**5,376.30**	**2,420.80**	**17.50**	**171.30**	**74.10**		**5.92**	**58.57**	**23.82**	**397.76**	**4,258.73**	**1,821.20**	**11.05**	**134.10**	**55.10**

			Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Assessment Unit Name	Type	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	Percent of Assessment Unit Lying Within Field Office	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
Continuous Resources	Mowry Gas	Gas				6,745.90	10,614.40	8,542.60	110.90	247.90	170.90	75.84%				5,116.41	8,050.46	6,479.11	84.11	188.02	129.62
	Niobrara Gas	Gas										2.07%				0.00	0.00	0.00	0.00	0.00	0.00
	Hilliard-Baxter-Mancos Gas	Gas				4,895.10	22,703.40	11,753.20	286.50	1,525.20	752.20	77.03%				3,770.72	17,488.56	9,053.56	220.69	### ###	579.42
	Almond Gas	Gas				10,013.50	17,311.30	13,349.70	113.50	319.90	200.20	12.17%				1,218.21	2,106.04	1,624.08	13.81	38.92	24.36
	Rock Springs-Ericson Gas	Gas				8,768.90	16,320.00	12,178.00	89.20	221.70	146.10	19.98%				1,752.21	3,261.09	2,433.43	17.82	44.30	29.19
	Mesaverde Coal-Bed Gas (Mesaverde TPS)	CBG				126.10	427.30	248.70				27.97%				35.27	119.53	69.57	0.00	0.00	0.00
	Mesaverde-Lance-Fort Union Gas	Gas				8,320.10	20,695.40	13,635.20	329.20	1,016.90	613.60	37.30%				3,103.04	7,718.51	5,085.35	122.78	379.26	228.85
	Mesaverde Coal-Bed Gas (Mesaverde-Lance-Fort Union TPS)	CBG				13.70	47.30	27.30				2.08%				0.29	0.99	0.57	0.00	0.00	0.00
	Fort Union Coal-Bed Gas (Mesaverde-Lance-Fort Union TPS)	CBG				35.30	151.90	80.80				7.69%				2.71	11.68	6.21	0.00	0.00	0.00
	Lewis Gas	Gas				8,764.90	19,677.40	13,535.70	305.00	868.70	541.40	12.17%				1,066.31	2,393.89	1,646.71	37.11	105.68	65.86
	Lance-Fort Union Gas	Gas				4,450.60	11,829.10	7,583.30	39.40	128.40	75.80	10.13%				450.99	1,198.66	768.43	3.99	13.01	7.68
	Lance Coal-Bed Gas	CBG				78.20	295.50	165.00				20.76%				16.24	61.35	34.26	0.00	0.00	0.00
	Fort Union Coal-Bed Gas (Lance-Fort Union TPS)	CBG				513.90	1,545.40	942.50				26.45%				135.92	408.73	249.27	0.00	0.00	0.00
	Wasatch-Green River Gas	Gas										37.82%				0.00	0.00	0.00	0.00	0.00	0.00
	Wasatch-Green River Coal-Bed Gas	CBG				27.80	122.60	64.70				4.27%				1.19	5.24	2.76	0.00	0.00	0.00
	Total Undiscovered Continuous Resource		**0.00**	**0.00**	**0.00**	**52,754.00**	**121,741.00**	**82,106.70**	### ###	**4,328.70**	### ###		**0.00**	**0.00**	**0.00**	**16,669.51**	**42,824.71**	**27,453.31**	**500.31**	### ###	**1,064.98**
	Total Undiscovered Resource		**7.30**	**66.40**	**27.80**	**53,364.70**	**127,117.30**	**84,527.50**	### ###	**4,500.00**	### ###		**5.92**	**58.57**	**23.82**	**17,067.27**	**47,083.44**	**29,274.51**	**511.36**	### ###	**1,120.09**

MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

NGL = Natural Gas Liquids
MMBNGL = Million Barrels of Natural Gas Liquids
= Not Applicable

[1] Potential resource is assumed to be evenly distributed across each play area or assessment unit.

Data from Kirschbaum et al., 2002

Table 11a. Estimated conventional oil and gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Rock Springs Planning Area within each development potential classification type.

Development Potential	Acres	Area (townships)	Average new wells per township	Percent of Planning Area
Very High	366,527	15.91	240	6.84
High	172,293	7.48	100	3.22
Moderate	463,210	20.10	35	8.64
Low	938,424	40.73	12.5	17.51
Very Low	2,919,726	126.72	2.5	54.49
None	269,164	11.68	0	5.02
Not Assessed	229,215	9.95	0	4.28
Totals	**5,358,559**	**232.58**		**100.00**

Table 11b. Estimated conventional oil and gas development potential classification acres on Federal oil and gas minerals, number of townships, projected average drilling densities, and percentage of Federal oil and gas minerals within each development potential classification type.

Development Potential	Acres	Area (townships)	Average new wells per township	Percent of Planning Area
Very High	337,910	14.67	240	9.56
High	132,825	5.76	100	3.76
Moderate	278,949	12.11	35	7.90
Low	515,986	22.40	12.5	14.60
Very Low	1,814,224	78.74	2.5	51.35
None	231,139	10.03	0	6.54
Not Assessed	221,918	9.63	0	6.28
Totals	**3,532,951**	**153.34**		**100.00**

Table 12a. Estimated coalbed natural gas development potential classification acres, number of townships, projected average drilling densities, and percentage of the Rock Springs Planning Area within each development potential classification type.

Development Potential	Acres	Area (townships)	Average new wells per township	Percent of Planning Area
Moderate	117,915	5.12	20	2.20
Low	177,660	7.71	6	3.32
Very Low	2,049,667	88.96	1	38.25
None	2,784,101	120.84	0	51.96
Not Assessed	229,215	9.95	0	4.28
Totals	**5,358,559**	**232.58**		**100.00**

Table 12b. Estimated coalbed natural gas development potential classification acres on Federal oil and gas minerals, number of townships, projected average drilling densities, and percentage of Federal oil and gas minerals within each development potential classification type.

Development Potential	Acres	Area (townships)	Average new wells per township	Percent of Planning Area
Moderate	77,608	3.37	20	2.20
Low	126,996	5.51	6	3.59
Very Low	1,325,588	57.53	1	37.52
None	1,780,842	77.29	0	50.41
Not Assessed	221,918	9.63	0	6.28
Totals	**3,532,951**	**153.34**		**100.00**

Table 13.
Forecast of annual and cumulative baseline conventional oil and gas and coalbed natural gas production in the Rock Springs Planning Area for 2012 through 2031.

Year	Conventional Gas Production (thousand cubic feet)	Conventional Oil Production (Barrels)	Coalbed Natural Gas Production (thousand cubic feet)
2012	37,841,797	888,486	17,360
2013	50,672,640	1,246,671	32,617
2014	56,205,195	1,395,576	51,122
2015	92,843,985	2,273,316	77,413
2016	108,543,780	2,684,749	112,616
2017	118,041,082	2,932,809	157,555
2018	137,478,135	3,408,404	210,556
2019	155,750,067	3,846,400	271,945
2020	168,556,104	4,152,399	340,289
2021	196,906,939	4,820,607	414,239
2022	209,047,927	5,125,422	492,138
2023	245,522,925	5,966,244	572,079
2024	253,921,796	6,188,718	652,244
2025	285,311,801	6,902,682	730,690
2026	304,230,812	7,374,078	805,284
2027	329,371,009	7,949,747	874,341
2028	366,206,638	8,832,743	936,264
2029	379,874,251	9,171,318	989,286
2030	388,579,314	9,374,888	1,032,144
2031	409,070,480	9,838,741	1,063,865
Cumulative Production	**4,293,976,677**	**104,373,998**	**9,834,047**

Table 14. Alternative B summary of the number of acres in each restriction category for each development potential type within the Rock Springs Planning Area.

Development Potential	Category D Unleased Bureau Acres	Category D Leased Bureau Acres	Category D Non-Bureau Acres	Category C Bureau Acres	Category B Bureau Acres
Conventional Oil and Gas					
Very High	84,639	162,418	14,635	64,352	19,196
High	13,174	64,887	3,006	28,134	16,120
Moderate	59,556	96,891	12,052	62,176	24,856
Low	82,211	149,430	12,152	173,846	32,973
Very Low	937,259	293,755	98,299	313,366	70,317
Coalbed Natural Gas					
Moderate	5,563	14,055	1,279	23,600	3,362
Low	37,086	17,726	1,961	25,785	8,027
Very Low	472,168	326,146	71,887	299,913	74,375

Table 15. Analysis results showing the calculated reduction in Bureau and non-Bureau wells of each type for Alternative B due to Category D restrictions within the Rock Springs Planning Area.

Development Potential	Well Locations per Township	Unleased Bureau Mineral Townships	Leased Bureau Mineral Townships	Non-Bureau Mineral Townships	Percent Reduction in Bureau Wells (unleased/leased)	Percent Reduction in non-Bureau Wells	Reduction in Bureau Wells	Reduction in Non-Bureau Wells
Conventional Oil and Gas								
Very High	240	3.67	7.05	0.64	100/7	6	1,000	9.15
High	100	0.57	2.82	0.13	100/30	5	142	0.65
Moderate	35	2.58	4.21	0.52	100/55	5	171	0.92
Low	12.5	3.57	6.49	0.53	100/70	6	101	0.40
Very Low	2.5	40.68	12.75	4.27	100/80	9	127	0.96
Coalbed Gas								
Moderate	20	0.24	0.61	0.06	100/85	75	15	0.83
Low	6	1.61	0.77	0.09	100/95	85	14	0.43
Very Low	1.	20.49	14.16	3.12	100/95	85	34	2.65

Table 16. Conventional and coalbed natural gas well counts, by alternative, for Bureau and Non-Bureau managed wells within the Rock Springs Planning Area.

	Baseline		Alternative A		Alternative B		Alternative C	
	Conventional	**CBNG**	**Conventional**	**CBNG**	**Conventional**	**CBNG**	**Conventional**	**CBNG**
All Wells	6,095.3911	237.5842	5,766.4146	203.3229	4,247.4266	148.3638	5,901.8292	219.9269
Bureau managed wells	4,996.9384	157.9741	4,668.3525	124.6905	3,161.0440	72.6727	4,803.5519	140.9715
Non-Bureau managed wells	1,098.4527	79.6101	1,098.0621	78.6324	1,086.3826	75.6911	1,098.2773	78.9554

Table 17.
Forecast of annual and cumulative Alternative A conventional oil and gas and coalbed natural gas production in the Rock Springs Planning Area for 2012 through 2031.

Year	Conventional Gas Production (thousand cubic feet)	Conventional Oil Production (Barrels)	Coalbed Natural Gas Production (thousand cubic feet)
2012	35,798,340	840,508	14,857
2013	47,936,317	1,179,351	27,914
2014	53,170,114	1,320,215	43,750
2015	87,830,410	2,150,557	66,250
2016	102,682,416	2,539,773	96,377
2017	111,666,864	2,774,437	134,836
2018	130,054,316	3,224,350	180,194
2019	147,339,563	3,638,694	232,731
2020	159,454,074	3,928,169	291,219
2021	186,273,964	4,560,294	354,506
2022	197,759,339	4,848,649	421,172
2023	232,264,687	5,644,067	489,585
2024	240,210,019	5,854,527	558,190
2025	269,904,964	6,529,937	625,325
2026	287,802,348	6,975,878	689,162
2027	311,584,975	7,520,461	748,261
2028	346,431,480	8,355,775	801,255
2029	359,361,041	8,676,067	846,631
2030	367,596,031	8,868,644	883,309
2031	386,980,674	9,307,449	910,456
Cumulative Production	**4,062,101,936**	**98,737,802**	**8,415,977**

Table 18.
Forecast of annual and cumulative Alternative B conventional oil and gas and coalbed natural gas production in the Rock Springs Planning Area for 2012 through 2031.

Year	Conventional Gas Production (thousand cubic feet)	Conventional Oil Production (Barrels)	Coalbed Natural Gas Production (thousand cubic feet)
2012	26,368,164	619,097	10,841
2013	35,308,696	868,680	20,369
2014	39,163,780	972,437	31,926
2015	64,693,689	1,584,047	48,344
2016	75,633,306	1,870,733	70,329
2017	82,251,026	2,043,581	98,393
2018	95,794,764	2,374,976	131,492
2019	108,526,647	2,680,172	169,830
2020	117,449,893	2,893,392	212,510
2021	137,204,755	3,358,999	258,692
2022	145,664,596	3,571,394	307,340
2023	171,080,374	4,157,279	357,263
2024	176,932,707	4,312,299	407,326
2025	198,805,263	4,809,789	456,316
2026	211,988,030	5,138,258	502,900
2027	229,505,719	5,539,384	546,026
2028	255,172,785	6,154,655	584,697
2029	264,696,378	6,390,574	617,809
2030	270,762,066	6,532,422	644,574
2031	285,040,310	6,855,635	664,384
Cumulative Production	**2,992,042,949**	**72,727,802**	**6,141,362**

Table 19.
Forecast of annual and cumulative Alternative C conventional oil and gas and coalbed natural gas production in the Rock Springs Planning Area for 2012 through 2031.

Year	Conventional Gas Production (thousand cubic feet)	Conventional Oil Production (Barrels)	Coalbed Natural Gas Production (thousand cubic feet)
2012	36,638,428	860,232	16,070
2013	49,061,250	1,207,027	30,194
2014	54,417,870	1,351,197	47,324
2015	89,891,546	2,201,025	71,661
2016	105,092,088	2,599,374	104,249
2017	114,287,376	2,839,546	145,849
2018	133,106,330	3,300,017	194,912
2019	150,797,215	3,724,084	251,739
2020	163,196,020	4,020,353	315,006
2021	190,645,298	4,667,312	383,461
2022	202,400,203	4,962,434	455,572
2023	237,715,296	5,776,517	529,574
2024	245,847,083	5,991,917	603,782
2025	276,238,886	6,683,177	676,400
2026	294,556,272	7,139,582	745,451
2027	318,897,011	7,696,945	809,377
2028	354,561,267	8,551,862	866,700
2029	367,794,250	8,879,670	915,782
2030	376,222,492	9,076,767	955,456
2031	396,062,039	9,525,869	984,820
Cumulative Production	**4,157,428,219**	**101,054,905**	**9,103,377**

Table 20.
Existing and projected surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area .

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Conventional Oil and Gas	6,095	4,997	7.1 successful and 5.6 for drilled and abandoned	41,906	34,354
New Coalbed Natural Gas	238	158	7.1 successful and 5.6 for drilled and abandoned	1,669	1,110
Existing Conventional Oil and Gas	2,259	1,536	2.64	5,964	4,055
Existing Coalbed Natural Gas	52	28	2.64	137	74
Total Wells	**8,644**	**6,719**	**Total Disturbance**	**49,676**	**39,593**

Disturbance Associated With Just New Producing Wells and With Existing Active Wells Less Abandonments (Long-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Producing Conventional Oil and Gas	4,572	3,748	2.64	12,069	9,894
New Producing Coalbed Natural Gas	190	126	2.64	502	334
Remaining Existing Conventional Oil and Gas	1,920	1,306	2.64	5,069	3,447
Remaining Existing Coalbed Natural Gas	0	0	2.64	0	0
Total Wells	**6,682**	**5,180**	**Total Disturbance**	**17,640**	**13,674**

Table 21.

Existing and projected Alternative A surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area .

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Conventional Oil and Gas	5,766	4,668	7.1 successful and 5.6 for drilled and abandoned	39,644	32,095
New Coalbed Natural Gas	203	125	7.1 successful and 5.6 for drilled and abandoned	1,428	876
Existing Conventional Oil and Gas	2,259	1,536	2.64	5,964	4,055
Existing Coalbed Natural Gas	52	28	2.64	137	74
Total Wells	**8,281**	**6,357**	**Total Disturbance**	**47,173**	**37,100**

Disturbance Associated With Just New Producing Wells and With Existing Active Wells Less Abandonments (Long-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Producing Conventional Oil and Gas	4,325	3,501	2.64	11,417	9,243
New Producing Coalbed Natural Gas	163	100	2.64	429	263
Remaining Existing Conventional Oil and Gas	1,920	1,306	2.64	5,069	3,447
Remaining Existing Coalbed Natural Gas	0	0	2.64	0	0
Total Wells	**6,408**	**4,907**	**Total Disturbance**	**16,916**	**12,953**

Table 22.

Existing and projected Alternative B surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area .

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Conventional Oil and Gas	4,247	3,161	7.1 successful and 5.6 for drilled and abandoned	29,201	21,732
New Coalbed Natural Gas	148	73	7.1 successful and 5.6 for drilled and abandoned	1,042	511
Existing Conventional Oil and Gas	2,259	1,536	2.64	5,964	4,055
Existing Coalbed Natural Gas	52	28	2.64	137	74
Total Wells	**6,707**	**4,798**	**Total Disturbance**	**36,344**	**26,372**

Disturbance Associated With Just New Producing Wells and With Existing Active Wells Less Abandonments (Long-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Producing Conventional Oil and Gas	3,186	2,371	2.64	8,410	6,259
New Producing Coalbed Natural Gas	119	58	2.64	313	153
Remaining Existing Conventional Oil and Gas	1,920	1,306	2.64	5,069	3,447
Remaining Existing Coalbed Natural Gas	0	0	2.64	0	0
Total Wells	**5,224**	**3,735**	**Total Disturbance**	**13,792**	**9,859**

Table 23.
Existing and projected Alternative C surface disturbance associated with conventional oil and gas and coalbed natural gas wells in the Rock Springs Planning Area .

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Conventional Oil and Gas	5,902	4,804	7.1 successful and 5.6 for drilled and abandoned	40,575	33,024
New Coalbed Natural Gas	220	141	7.1 successful and 5.6 for drilled and abandoned	1,545	990
Existing Conventional Oil and Gas	2,259	1,536	2.64	5,964	4,055
Existing Coalbed Natural Gas	52	28	2.64	137	74
Total Wells	**8,433**	**6,509**	**Total Disturbance**	**48,221**	**38,144**

Disturbance Associated With Just New Producing Wells and With Existing Active Wells Less Abandonments (Long-Term Disturbance)					
Wells			**Acres of Surface Disturbance**		
Well Type	**All Lands**	**BLM Managed**	**Well Pad + Access Roads + Pipelines**	**All Lands**	**BLM Managed**
New Producing Conventional Oil and Gas	4,426	3,603	2.64	11,686	9,511
New Producing Coalbed Natural Gas	176	113	2.64	464	298
Remaining Existing Conventional Oil and Gas	1,920	1,306	2.64	5,069	3,447
Remaining Existing Coalbed Natural Gas	0	0	2.64	0	0
Total Wells	**6,522**	**5,021**	**Total Disturbance**	**17,219**	**13,256**