REASONABLE FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS CIMARRON AND COMANCHE NATIONAL GRASSLANDS, KANSAS AND COLORADO

Point of Rocks, Kansas, Cimarron National Grasslands(USDA Forest Service photograph)

DEAN P. STILWELL,
AMBER L. ROBBINS,
ALFRED M. ELSER, Ph.D., and
STAN W. DAVIS-LAWRENCE

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

prepared for:
U.S.D.A. FOREST SERVICE
PIKE AND SAN ISABEL NATIONAL FORESTS, CIMARRON AND COMANCHE NATIONAL GRASSLANDS

FINAL REPORT

September 15, 2011

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

WYOMING STATE OFFICE

RESERVOIR MANAGEMENT GROUP

FINAL REPORT

Reasonable Foreseeable Development Scenario for Oil and Gas
Cimarron and Comanche National Grasslands, Kansas and Colorado
September 15, 2011

Prepared By:

Signature	Signature	Signature	Signature
Dean P. Stilwell	Amber L Robbins	Alfred M. Elser, Ph.D.	Stan W. Davis-Lawrence
Name	Name	Name	Name
Geologist PG-1070	Geologist	Geologist	Petroleum Engineer
Title	Title	Title	Title
September 15, 2011	September 15, 2011	September 15, 2011	September 15, 2011
Date	Date	Date	Date

Reviewed By:

Signature

J. David Chase
Name

Chief, Reservoir Management Group
Title

09/15/2011
Date

GEOLOGIC OVERVIEW 11

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS 11

EXPLORATORY ACTIVITY AND OPERATIONS 12
FEDERAL DEVELOPMENT CONTRACTS 16
FEDERAL OIL AND GAS UNIT AGREEMENTS 16
TYPICAL DRILLING AND COMPLETION SEQUENCE 18
DRAINAGE PROTECTION 19
HISTORICAL DRILLING AND COMPLETION ACTIVITY AND TECHNIQUES EMPLOYED FOR CONVENTIONAL OIL AND GAS 19
1898 TO 1031 20
1931 TO 1950 20
1951 TO 1960 21
1961 TO 1970 21
1971 TO 1980 21
1981 TO 1990 22
1991 TO 2000 22
2001 TO 2010 23
TECHNOLOGY DEVELOPMENT 23
DRILLING AND COMPLETION ACTIVITY 23
DEEP WELL DRILLING 25
SHALLOWER WELL DRILLING: 5,000 FEET AND GREATER 25
SHALLOWEST WELL DRILLING: LESS THAN 5,000 FEET 26
SUMMARY OF CURRENT DRILLING TECHNIQUES 27
Directional and Horizontal Drilling and Completion Activity 27
Slimhole Drilling and Coiled Tubing 28
Light Modular Drilling Rigs and Pad Drilling 29
Pneumatic Drilling 30
Measurement-While-Drilling 30
Improved Drill Bits 30
SUMMARY OF CURRENT COMPLETION TECHNIQUES 30
SUMMARY OF CONVENTIONAL OIL AND GAS PRODUCTION AND ABANDONMENT TECHNIQUES 32
OIL AND GAS PRODUCTION 33
HYDROGEN SULFIDE OCCURRENCE 34
CARBON DIOXIDE 35
HELIUM GAS 36
NITROGEN GAS 36
ACID GAS REMOVAL AND RECOVERY 37
ARTIFICIAL LIFT OPTIMIZATION 37
GLYCOL DEHYDRATION 37
PRODUCED WATER MANAGEMENT 37

LEAK DETECTION AND LOW-BLEED EQUIPMENT 38
VAPOR RECOVERY UNITS 38
UNDERGROUND GAS STORAGE 38

PREVIOUS ASSESSMENTS OF OIL AND GAS RESOURCES 39

POTENTIAL GAS COMMITTEE 39
ATLAS OF MAJOR ROCKY MOUNTAIN RESERVOIRS 39
U.S. DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY 39
U.S. GEOLOGICAL SURVEY ASSESSMENTS 39
RAND CORPORATION ASSESSMENTS 40

OIL AND GAS OCCURRENCE POTENTIAL 41

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2011-2030 42

OIL AND GAS PRICE ESTIMATES 42
GAS PRICES 42
OIL PRICES 44
LEASING 46
PROJECTIONS OF FUTURE OIL AND GAS DRILLING ACTIVITY 47
PROJECTED OIL AND GAS DRILLING ACTIVITY 47
PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION 48
ESTIMATED FUTURE CONVENTIONAL OIL AND GAS PRODUCTION 48
POTENTIAL FUTURE CARBON DIOXIDE SEQUESTRATION ACTIVITIES 49

POTENTIAL OIL AND GAS SURFACE DISTURBANCE 50

SUMMARY 51

APPENDIX 1 – U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED TECHNICALLY RECOVERABLE OIL AND GAS RESOURCES WITHIN THE PIKE AND SAN ISABLE NATIONAL FORESTS STUDY AREA 52

INTRODUCTION 52
RATON BASIN PROVINCE ASSESSMENT 52
TOTAL PETROLEUM SYSTEM AND ASSESSMENT UNIT SUMMARIES 53
JURASSIC-CRETACEOUS COMPOSITE TOTAL PETROLEUM SYSTEM 53
Jurassic-Lower Cretaceous Reservoirs Assessment Unit 53

ANADARKO BASIN PROVINCE ASSESSMENT **54**
PLAY SUMMARIES 54
UPPERMOST ARBUCKLE PLAY 55
INTERNALLY SOURCED ARBUCKLE PLAY (HYPOTHETICAL) 55
SIMPSON OIL AND GAS PLAY 55
VIOLA OIL AND GAS PLAY 56
MISENER OIL PLAY 56
LOWER MISSISSIPPIAN STRATIGRAPHIC OIL AND GAS PLAY 56
UPPER MISSISSIPPIAN STRATIGRAPHIC GAS AND OIL PLAY 57
MORROW SANDSTONE GAS AND OIL STRATIGRAPHIC PLAY 57
ATOKAN LIMESTONE STRATIGRAPHIC GAS AND OIL PLAY 57
LOWER DESMOINESIAN STRATIGRAPHIC GAS AND OIL PLAY 58
UPPER DESMOINESIAN OIL AND GAS PLAY 58
LOWER MISSOURIAN STRATIGRAPHIC OIL AND GAS PLAY 59
UPPER MISSOURIAN OIL AND GAS PLAY 59
LOWER VIRGILIAN SANDSTONE GAS AND OIL PLAY 59
UPPER VIRGILIAN STRATIGRAPHIC OIL AND GAS PLAY 60
PERMIAN CARBONATE STRATIGRAPHIC GAS PLAY 60
DENVER BASIN PROVINCE ASSESSMENT **61**
PLAY SUMMARIES 61
TOTAL PETROLEUM SYSTEMS AND ASSESSMENT UNIT SUMMARIES 61
LOWER CRETACEOUS TOTAL PETROLEUM SYSTEM 62
Dakota Group (Combined J and D Sandstones) Play and Dakota Group and D Sandstone Assessment Unit 62
LAS ANIMAS ARCH PROVINCE ASSESSMENT **63**

GLOSSARY **73**

Figure List

Figure 1. Cimarron and Comanche National Grasslands Study Area and its location within Colorado and Kansas.
Figure 2a. Location and initial status of all oil and gas wells drilled within the Comanche National Grassland Study Area.
Figure 2b. Location and initial status of oil and gas wells drilled within the Cimarron National Grassland Study Area.
Figure 3. Shaded relief map with major structural elements and selected geologic units of the Cimarron and Comanche National Grasslands Study Area.
Figure 4. Stratigraphic chart of the Hugoton Embayment and Las Animas Arch within the Cimarron and Comanche National Grasslands Study Area (after Henry and Hester, 1995; and Keighin, 1995).
Figure 5. Stratigraphic chart of the Raton basin within the Cimarron and Comanche National Grasslands Study Area (after Higley, 2007).
Figure 6a. Oil and gas fields within the Comanche National Grassland Study Area (Colorado Geological Survey, 2011).
Figure 6b. Oil and gas fields within the Cimarron National Grassland portion of the Study Area (Kansas Geological Survey, 2011).
Figure 7. Location of Federal oil and gas unit agreements and gas storage fields within the Cimarron and Comanche National Grasslands Study Area.
Figure 8. Location of Federal communitization agreements within the Cimarron and Comanche National Grasslands Study Area.
Figure 9a. Comanche National Grassland Study Area location of all oil and gas wells still in an active status.
Figure 9b. Cimarron National Grassland Study Area locations of all oil and gas wells still in an active status and well locations with an active application to drill.
Figure 10. Wells spudded in the Colorado part of the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).
Figure 11. Wells spudded in the Kansas part of the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).
Figure 12. All wells spudded in the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).
Figure 13. True vertical depths of vertical, directional, and horizontal wells within the Cimarron and Comanche National Grasslands Study Area.
Figure 14. Annual and cumulative oil production from wells in the Cimarron and Comanche National Grasslands Study Area.
Figure 15. Annual and cumulative gas production from wells in the Cimarron and Comanche National Grasslands Study Area.
Figure 16. Annual and cumulative water production from wells in the Cimarron and Comanche National Grasslands Study Area.
Figure 17. Potential for occurrence of oil and gas and known carbon dioxide or other non-hydrocarbon gas wells in fields within the Cimarron and Comanche National Grasslands Study Area.
Figure 18. Colorado historical natural gas prices with future natural gas price projections (Energy Information Administration, 2011a).

Figure 19. Kansas historical natural gas prices with future natural gas price projections (Energy Information Administration, 2011a).
Figure 20. Colorado historical crude oil prices with future oil price projections (Energy Information Administration, 2011a).
Figure 21. Kansas historical crude oil prices with future oil price projections (Energy Information Administration, 2011a).
Figure 22. Leased Federal oil and gas minerals within the Cimarron and Comanche National Grasslands Study Area.
Figure 23. Oil and gas development potential and projected drilling densities within the Cimarron and Comanche National Grasslands Study Area for 2011 through 2030.

Table List

Table 1. Federal oil and gas unit agreement data for the Cimarron and Comanche National Grasslands Study Area.
Table 2. Estimated oil and gas development potential classification acres, townships, average drilling densities, and percent within the Cimarron and Comanche National Grasslands Study Area.
Table 3. Projected annual and cumulative oil and gas production from new wells projected for the Analysis Period in the Cimarron and Comanche National Grasslands Study Area.
Table 4. Cimarron and Comanche National Grasslands Study Area disturbance associated with wells projected for the baseline scenario for the 2011-2030 period and for existing active wells.

Appendix 1 Figure List

Figure A1-1. Location of the Raton Basin 2007, Denver Basin 2007, Anadarko Basin 1995, and Las Animas Arch 1995 province boundaries within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-2. Location of the 2007 Raton Basin Province Jurassic-Cretaceous Composite Total Petroleum System, Jurassic Lower Cretaceous Reservoirs Assessment Units within the Pike and San Isabel National Forests Study Area.
Figure A1-3. Location of the 2011 Anadarko Basin Province Woodford Composite Total Petroleum System assessment units within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-4. Location of the 2011 Anadarko Basin Province Pennsylvanian Composite Total Petroleum System assessment units within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-5. Location of the 1995 Anadarko Basin Province Ordovician play boundaries within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-6. Location of the 1995 Anadarko Basin Province Devonian-Mississippian play boundaries within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-7. Location of the 1995 Anadarko Basin Province Lower Pennsylvanian play boundaries within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-8. Location of the 1995 Anadarko Basin Province Upper Pennsylvanian-Permian play boundaries within the Cimarron and Comanche National Grasslands Study Area.
Figure A1-9. Location of the 2007 Denver Basin Province Lower Cretaceous Total Petroleum System (assessment unit and play) within the Cimarron and Comanche National Grasslands Study Area.

Appendix 1 Table List

Table A1-1. Data for U.S. Geological Survey 2007 assessment of undiscovered conventional accumulation assessment units, Raton Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-2. U.S. Geological Survey 2007 estimated undiscovered technically recoverable resource quantities, Raton Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-3. U.S. Geological Survey 2011 estimated undiscovered technically recoverable resources for assessment units, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-4. Data for U.S. Geological Survey 1995 assessment of undiscovered conventional accumulation plays, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-5. U.S. Geological Survey 1995 estimated undiscovered technically recoverable resources for plays, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-6. Data for U.S. Geological Survey 2002 assessment of undiscovered conventional assessment units in the Denver Basin Province, Cimarron and Comanche National Grasslands Study Area.
Table A1-7. U.S. Geological Survey 2002 estimated undiscovered technically recoverable resources for assessment units, Denver Basin Province, Cimarron and Comanche National Grasslands Study Area.

INTRODUCTION

The Cimarron and Comanche National Grasslands Study Area (hereafter the Study Area) represents the lands managed by the Pike and San Isabel National Forests Cimarron and Comanche National Grasslands office of the U.S. Department of Agriculture (hereafter the Forest Service). Of the approximately 4,292,225 acres within the Study Area, the Forest Service manages public lands within the approximate 1,116,859-acre Cimarron National Grassland boundary in southeastern Colorado and within the approximate 342,299-acre Comanche National Grassland boundary in southwestern Kansas (Figure 1). Additional private, state, and other federal lands are included within the study area to aid in cumulative analysis of future projected activities.

The Forest Service has initiated an analysis to determine which lands within the Cimarron and Comanche National Grasslands should be made available for oil and gas leasing. As part of that analysis an Environmental Impact Statement will be prepared. In support of the Environmental Impact Statement, we gathered information on the potential trend and magnitude of reasonably foreseeable future oil and gas activity in order to analyze the associated environmental impacts. This reasonable foreseeable development projection technically analyzes the oil and gas resource known to occur and potentially occurring within the Study Area and projects future development potential and activity levels for the analysis period 2011 through 2030 (see glossary for analysis period).

Individual wells may produce oil, natural gas (see Glossary), or a combinational of oil and natural gas. In addition, minor amounts of non hydrocarbon gases may be present in some oil and gas wells within the Study Area. A separate discussion of these types of gases will be presented below. Projections of future exploration development will consider all oil and gas drilling activity and will be combined with development of any non hydrocarbon gases that may also be present within the Study Area. Since there are no indications that coalbed natural gas (see Glossary) is present within the Study area, no discussion of this resource type will be presented. Figure 2a shows historic and present oil and gas related development areas for all lands within the Colorado part of the Study Area and Figure 2b shows historic and present oil and gas related development areas for all lands within the Kansas part of the Study Area.

Our analysis makes a base line projection that assumes future oil and gas related activity levels on all assessed lands within the Study Area will not be constrained by management-imposed conditions (Rocky Mountain Federal Leadership Forum, 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.

The reasonable foreseeable development evaluation and projections presented below review and analyze past, present, and potential future exploratory, development, and production operations and activities. It also presents occurrence potential for oil and gas as well as available estimates of the hydrocarbon resources and non-hydrocarbon gas resources that may be present within the Study Area. Additional factors used to project future activities include (but are not limited to) a review of published 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, 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).

The Study Area contains about 4,292,225 surface acres of all mineral ownership types. Oil and gas mineral ownership data for the Kansas lands is not available for analysis, although active Federal oil and gas lease information is available. It shows that at least 69,300 acres of Federal oil and gas lease cover the Cimarron National Grassland in Kansas. We assume that a limited number of small parcels could be unleased and may add up to an additional 1,000 acres that would be managed by the Forest Service in the 342,209-acre Cimarron National Grassland. All other lands in the Kansas part of the Study Area are assumed to be managed by state and private interests.

Oil and gas mineral ownership data is available for the Colorado lands. The Colorado part of the Study Area contains about 1,251,010 acres of Federal oil and gas mineral ownership, or about 31.95 percent of the 3,915,896 total acres in the Colorado part of the Study Area. The remaining 2,664,886 acres (68.05 percent) is managed by state and private interests. The Forest Service manages a portion of the Federal oil and gas mineral lands in the Colorado part of the Study Area (359,709) acres, or about 28.75 percent of the 1,251,010 acres. The Bureau of Land Management manages about 665,624 acres, or 53.21 percent of Federal oil and gas mineral lands within the Colorado part of the Study Area. The remaining 18.04 percent (225,677 acres) of Federal oil and gas mineral lands lie under Department of Defense management. Decisions made as part of the Environmental Impact Statement for the Study Area will not be made for the Bureau of Land Management, Department of Defense, and state and privately managed lands.

We would like to thank Ms. Cathy Stilwell of the Bureau of Land Management Wyoming State Office Reservoir Management Group staff for the important Geographic Information System contributions that she has made to this reasonable foreseeable development analysis. In addition we would like to thank John Dow of the U.S. Forest Service (Pueblo, Colorado) for his assistance in obtaining industry data contributions and preparing the development potential analysis. Leslie Peterson of the Bureau of Land Management (Canon City, Colorado) provided assistance in preparing the development potential analysis and surface disturbance assumptions. Richard Bennin, with the Forest (Elkhart, Kansas), assisted in making surface disturbance assumptions and with the development potential analysis.

GEOLOGIC OVERVIEW

Most of the Study Area is within the Great Plains physiographic province, a region of distinct topography and geology. The Great Plains cover a large area of flat land (prairie, steppe, and grassland) lying west of the Mississippi River and east of the Rocky Mountains. Parts of two divisions (High Plains and Colorado Piedmont) of the province occupy the Study area. The easternmost portion of the Study Area (Kansas and easternmost Colorado) lies within the High Plains subregion of the Great Plains. The High Plains is semi-arid, shortgrass prairie, with occasional buttes and rocky outcrops. The Colorado Piedmont covers most of the Colorado part of the Study area. This region consists of a broad hilly valley that is just under 5,000 feet in elevation, in front of the foothills of the Front Range.

The major structural elements of the Study Area are shown in Figure 3 and are after Tweto (1979) and Anderman (1961). Dike outcrops shown are of Eocene to Oligocene in age. The labeled Freezout Creek and Ute Pass faults are the major faults in the Study Area, with a few other faults unlabeled. The Denver basin axis marked is the southernmost plunge of this syncline.

The Sierra Grande uplift (Figure 3) extends northeastward to merge with the Las Animas arch, just off the map (Higley et al., 2007). Along the uplift there are large areas of Tertiary aged igneous rock that could consist of basalt flows and associated tuff, breccias, and conglomerate and small areas of igneous intrusives (Tweto, 1979). All sedimentary strata lying to the east of the Sierra Grande uplift are primarily of Early Cretaceous age and older. Younger strata are missing due to either nondeposition or erosion.

Merriam (1963) defined the Hugoton Embayment as a large, shelflike extension into western Kansas (and easternmost Colorado) of the larger Anadarko basin lying to the southeast. The western side of the embayment is limited by the Sierra Grande Uplift and too the north (just beyond the Study Area boundary) by the Las Animas Arch. Structure plunges to the south in the embayment. Precambrian rocks in the subsurface are overlain by as much as 9,500 feet of younger rocks in the Kansas part of the Study Area, making it the deepest structural basin in Kansas (Merriam, 1963). Industry often reports data from the Hugoton Embayment as being from the Anadarko basin; consequently these two names are used interchangeably in this report.

EXPLORATORY AND PRODUCTION ACTIVITY AND OPERATIONS

The following discussion brings together known information on past and present exploratory and production operations and activity for the Study Area. Information is presented in the approximate sequence that occurs when project areas or fields (see Glossary for field) 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 United States 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 (see Glossary for rotary drilling rig);
- seismograph (1914), which allowed one dimensional subsurface imaging;
- 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, shale oil, and the use of carbon dioxide in the flooding process to increase recoveries;
- advances in downhole tools (2000s), such as geosteering tools and recording devices; borehole (see Glossary) imagining; borehole seismic; and new logging tools that have allowed better assessment of unconventional types of reservoirs; and
- multi-discipline collaboration (2000s), which allows for better drilling decisions, higher success rates, improved risk assessment, and enhanced reservoir development.

Exploratory activity includes:

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

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

1. Locations of major tectonic features (Figure 3) that have developed over many millions of years. Some features (anticlines and faults) may improve opportunities for the development of oil and gas reservoirs while others (igneous intrusive and Precambrian rocks) may indicate reduced opportunities for the development of reservoirs. The limited amount of exploratory drilling in the area of the Sierra Grande uplift may be partly due to the igneous intrusive rocks occurring there.
2. The Hugoton Embayment contains thick sections of sediments with oil and gas potential (Beserra, 2008; Dubois et al., 2006; Sonnenberg et al., 1990; Watney, 1984; Matson and Schneider, 1968; Davis, 1964; and Pustmueller, 1958). Most of reservoir targets in the Study Area are Lower Permian and Pennsylvanian aged carbonates, with the Chase, Shawnee, and Morrow groups accounting for most of the productive wells. Figure 4 presents a stratigraphic chart for the Hugoton Embayment portion of the Study Area that shows the nomenclature used for sedimentary accumulations used in this report. The Las Animas Arch lies just north of the Study Area in southeastern Colorado and is included in Figure 4 since these rock unit names often are used by industry in northern parts of the Study Area. In addition the Raton basin stratigraphic chart is included as Figure 5 since its rock unit names are often carried into well descriptions in the southwestern part of the Study Area.
3. Figure 6a shows oil and gas fields lying within the Colorado portion of the Study Area (Colorado Geological Survey, 2011) and Figure 6b shows those lying within the Kansas portion (Kansas Geological Survey, 2011). These fields help define areas were there has been the greatest historical interest in exploring for and developing the oil and gas resource within the Study Area. Almost all fields are located within the Hugoton Embayment. For convenience, the fields located in Kansas are often grouped together and called the Hugoton Gas Field. Only the Model and Nina View fields lay outside and west of the Hugoton Embayment. Helium was produced from Model field and carbon dioxide was produced from Nina View field.
4. Burial and thermal histories that could promote the development and preservation of diagenetic pore-throat traps (see Glossary) and oil and gas generation in the deeper parts of the Anadarko basin in Oklahoma with later migration to the northwest into reservoir traps in the Hugoton Embayment and Study Area (Beserra, 2008).
5. Structure traps (see Glossary) and/or stratigraphic traps (see Glossary), that have played a role in localizing some oil and gas accumulations within the Study Area.
6. Secondary porosity, produced by the dissolution of unstable grains (see Glossary) and rock fragments, is important in local accumulations.

We believe that these components are also important in exploring for and developing new oil and gas resources in the Study Area. In the last 10 years 254 new exploratory and development wells have been spudded (see glossary). Forty-one wells were spudded in

Colorado during this period. Twenty-one wells were drilled as wildcats with four productive, three that are shut-in, and the remaining 14 now abandoned. The remaining 20 wells were drilled as development wells with five productive, eight that are shut-in, and the remaining seven are abandoned.

Of the 212 wells drilled in the Kansas portion of the Study Area 51 were drilled as wildcat wells and 161 were drilled as development wells. The present status of the wildcat wells is:

- producing 15 wells,
- shut-in 6 wells,
- water disposal 1 well, and
- abandoned 29 wells.

The present status of the development wells is:

- producing 86 wells,
- shut-in 19 wells,
- injection 8 wells,
- water disposal 3 wells,
- water source 4 wells, and
- abandoned 41 wells.

Potential nonconventional (unconventional) hydrocarbon resources (see Glossary) do not appear to make up a portion of the hydrocarbon resource that may be explored for and developed in the Study Area in the future.

Innovative drilling and completion techniques have enabled the United States oil and gas industry to drill fewer dry holes and to recover more oil and gas reserves (see Glossary for 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 (2007a) has projected the increase in percentage of United States wells drilled successfully will be 0.2 percent per year to 2030.

During the last 10 years, exploratory and development activity has only occurred in the Hugoton Embayment part of the Study Area to explore for and develop additional natural gas and oil resources. In the Kansas part of the Study Area completions have been predominantly in the Lower Pennsylvanian Morrow Group and to a lesser extent in the Lower Permian Chase Group and Upper Pennsylvanian Wabaunsee and Shawnee groups. In the Colorado part of the Study Area completions have been split between the Lower Permian Sumner Group (Red Cave Sandstone) and the Upper Pennsylvanian Wabaunsee, Shawnee, and Lansing groups. Additional future exploratory drilling will be required to discover new resources in the Hugoton Embayment and western parts of the Study Area. 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; and
- advances in drilling that allow more cost-efficient tests of undepleted zones in mature fields, testing deeper zones in existing fields, and exploring new regions.

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

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. The U.S. Department of Energy (1999) estimated finding costs were approximately 2 to 16 dollars per barrel of oil equivalent in the 1970's. Finding costs then dropped to 4 to 8 dollars per barrel of oil equivalent in the 1993 to 1997 period. Finding costs then fluctuated around the higher end of this range for a number of years. During the 2003 to 2005 period, finding costs were 7.05 dollars per barrel of oil equivalent and they then increased by 60.9 percent to 11.34 dollars per barrel for the 2004 to 2006 period (Energy Information Administration, 2007b). Since the 2004 to 2006 period finding costs have increased considerably. During the 2005 to 2007 period they went to 13.72 dollars per barrel and then they jumped by 77 percent to 24.31 dollars per barrel for the 2006 to 2008 period (Energy Information Administration, 2009a). Most of this increase was reported to have come from a rise in exploration and development spending, which was amplified by a drop in reserves found. Producers have been willing to spend more to find oil and gas since prices received during this period had been higher.

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 United States 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, 2007b). Lifting costs increased to 12.16 dollars in 2007 and then increased over 24 percent in 2008 to 15.10 dollars (Energy Information Administration, 2009a). Lifting costs have increased in recent years because more producers have been willing to spend

more to produce oil and natural gas since their selling prices for oil and gas have been higher.

FEDERAL DEVELOPMENT CONTRACTS

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

FEDERAL OIL AND GAS UNIT AGREEMENTS

A Federal unit agreement is a contract between the Federal Government and lessees that involve 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. In the following years thousands of units have been created in the United States. Many are still active while others have terminated.

Federal oil and gas leases are incorporated into three active oil and gas unit agreement areas that lie wholly in the Comanche National Grassland (Colorado) and six that lie wholly in the Cimarron National Grassland (Kansas) of the Study Area (Figure 7). All nine units are considered to be secondary recovery to allow for logical enhanced recovery procedures. Information about each unit is summarized in Table 1. Oxy USA and Anadarko Production Corporation operate two units each while the other five operators manage only one unit each within the Study Area. Production in the three Colorado units is from zones in the Upper Pennsylvanian Lansing group while in Kansas all six units produce from zones in the Lower Pennsylvanian Morrow Group.

There are no gas storage units within the Study Area, but two fields are used for gas storage purposes. They will be discussed later in this report. The Flank gas storage field (Figure 7) does not lay on Forest Service managed lands. It is operated by Colorado Interstate Gas Company and has a capacity to store 19.89 billion cubic feet of gas (Energy Information Administration for EIA-191A). The Boehm gas storage field does lie within the Cimarron National Grassland. It is also operated by Colorado Interstate Gas Company and has a capacity to store 12.73 billion cubic feet of gas (Energy Information Administration for EIA-191A). Both fields store gas in Lower Pennsylvanian Morrow Group zones.

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

At present16 active communitization agreements lie within the Colorado portion of the Study Area (Figure 8). One communitization agreement lies within the Comanche National Grassland and the remaining 15 are on Bureau of Land Management lands. The Grassland communitization agreement occupies 640.51 acres of the total 10,251.95 acres of communitization agreements in the Colorado part of the Study Area. Crusader Energy Group LLC operates 14 communitization agreements and Energy Alliance Company and Berexco Incorporated operate one communitization agreement each.

There are presently 176 active communitization agreements within the Kansas portion of the Study Area (Figure 8). Three communitization agreements lie on Bureau of Land Management lands and the remaining 173 lie within the Cimarron National Grassland. The Bureau of Land Management communitization agreements account for about 478 acres and the communitization agreements within the Cimarron National Grassland account for about 108,394 acres. Operators with more than one communitization agreement include:

- Anadarko Production Corporation/Apx Corporation 45 agreements,
- Oxy USA Incorporated 42 agreements,
- Anadarko Production Corporation 27 agreements,
- El Paso E&P Company LP 12 agreements,
- Apx Corporation 11 agreements,

- Panhandle Eastern Pipeline 5 agreements,
- BP America Production Company 5 agreements,
- Matagorda Island Exp. 4 agreements,
- Coastal Oil & Gas Corporation 4 agreements,
- Mobil Exploration & Production US 3 agreements,
- Nadel & Gussman 2 agreements, and
- MM Energy Incorporated 2 agreements.

TYPICAL DRILLING AND COMPLETION SEQUENCE

Before an oil or gas well is drilled, an Application for Permit to Drill must be approved by the Colorado Oil and Gas Conservation Commission http://cogcc.state.co.us/ for wells drilled in Colorado and by the Kansas Corporation Commission's Oil & Gas Conservation Division http://www.kcc.state.ks.us/conservation/index.htm for those wells drilled in Kansas. If the well will be located on Federal lands, an Application for Permit to Drill must also be approved by the Bureau, which also requires Forest Service approval of associated surface use for wells proposed on the National Grasslands. Not every approved application is actually drilled. The drilling and completion sequence for a targeted reservoir in the Study Area generally involves:

- constructing the well pad, associated reserve pits, and the access road prior to moving the drilling equipment on to the well location;
- using rotary equipment, hardened drill bits, weighted drill pipe/collars, and drilling fluids to cool and lubricate the drill bit, which all result in easier penetration of the earth's surface;
- for horizontal boreholes, geosteering (intentional directional control of the borehole based on the results of downhole geological logging measurements) the drill bit to maintain correct hole trajectory and keep a borehole in a particular reservoir to maximize economic production;
- inserting casing and cementing it in place to protect subsurface resources 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 if the well is not successful and is immediately plugged and abandoned after drilling, or after the well has ceased production and is plugged and abandoned.

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

- access to 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, and
- better protection of sensitive environments and habitat.

DRAINAGE PROTECTION

Producing oil and gas wells may cause drainage (migration of hydrocarbons toward the borehole) from nearby lands. This drainage will result in the loss of oil and gas from those lands and result in loss of royalty revenues for landowners. Drainage is most often avoided or reduced by the drilling of a protective well. By protecting Federal 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

Total wells drilled in the Study Area are 3,507 wells and are shown on Figures 2a (Colorado part of Study Area) and Figure 2b (Kansas part of Study Area). There are 1,770 active wells with five of those wells being locations (waiting to be drilled). In

Colorado there are 981 active wells (Figure 9a) and in Kansas there are 2,526 wells (Figure 9b). Figure 10 shows all wells in the Colorado part of the Study Area by 10 year period that have a spudded date and Figure 11 shows all wells in the Kansas part of the Study Area that have a spudded date, again by 10 year period. There are no coalbed natural gas wells within the Study Area. Below is a summary of all the wells with a spudded date that have been drilled in the Study Area by ten year periods (Figure 12).

1898 to 1031

From 1898 to 1920, only six wells were drilled (Figure 12). The first was drilled as a service well and was later abandoned, while the next five wells were drilled and abandoned (0 percent success rate). All were located in Colorado with two drilled in Baca County, two in Otero County and two in Las Animas County, the first exploration in this part of Colorado. All of these wells were shallow, with the deepest well at 1,871 feet measured depth (IHS Energy Group, 2011).

A boom from 1921 to 1930 occurred in the Study Area. During this boom, 63 wells were drilled. Thirty-eight of the wells are gas wells, of which 15 are plugged and abandoned, 21 wells are still producing, and two wells are shut-in. The remaining 25 wells were drilled and abandoned (60.32 percent success rate).

The first wells drilled in the Kansas part of the Study Area were drilled in 1930 with 31 drilled and 30 of them productive as gas wells. Eight of the 30 wells have since been abandoned.

In the Colorado part of the Study Area Model Dome (Figure 6a), a closed anticline (Winchester, 1932), was being developed by 1926 from the Permian Yeso Formation. Girdler Corporation discovered nitrogen (79.71 percent), carbon dioxide (12.19 percent), oxygen (0.92 percent), and helium (7.18 percent) at Model Dome in Las Animas County (Winchester, 1932). By June of 1931, 5,160,000 cubic feet of helium had been produced (Shoenfelt, 1938). The Federal Government made the field a reserve for helium and shut-in the well for future needs (Brainerd and Van Tuyl, 1954). As of 1938, 172,790,000 cubic feet of estimated recoverable helium could be produced at Model Dome (Shoenfelt). Of the 11 wells drilled in Model Dome, the average depth drilled was 5,500 feet (IHS Energy Group, 2011). Four additional wells were drilled in the Model Dome field in the 1960s and 1980s. The remaining wells in the Colorado part of the Study Area were scattered and all were abandoned.

1931 to 1950

From 1931 to 1950, 121 wells were drilled (Figure 12). Twenty wells were drilled and abandoned (83.47 percent success rate). The successful wells were; one injection well, 84 producing gas wells, and 6 shut-in gas wells. One well is a plugged and abandoned oil well and 9 wells are plugged and abandoned gas wells. The greater Hugoton gas area in Kansas was a primary area being drilled during this period in Morton County and Stevens County, Kansas and Baca County, Colorado. The two major operators drilling during

this time period were the Panhandle Eastern Pipeline Company and Stanolind Oil and Gas Corporation. Average well depth was approximately 3,000 feet measured depth. Gas was the primary hydrocarbon produced.

1951 to 1960

From 1951 to 1960, there was a dramatic increase in the number of wells drilled (Figure 12). There were 734 wells drilled over this ten year period. One hundred thirty-seven wells were drilled and abandoned (81.34 percent success rate). The remaining wells are enhanced oil recovery wells (8), injection wells (14), gas storage wells (3), gas wells (465), oil and gas wells (7), oil wells (99), and service wells (1). These wells are producing, shut-in, or have been plugged and abandoned. The two major fields drilled were the Hugoton gas area (generally considered as covering the eastern part of the Kansas area) and the greater Greenwood Gas area (generally considered as covering the western part of the Kansas area). These two areas each had over 200 wells drilled. Gas again was the main hydrocarbon targeted. Average depth drilled was approximately 3,850 feet measured depth. Major operators included Amerada Hess Corporation, Anadarko Petroleum Company,

1961 to 1970

From 1961 to 1970, 519 additional wells were drilled in the Study Area (Figure 12). Of these wells, 216 were drilled and abandoned (58.38 percent success rate). The remaining wells are gas storage wells (24), enhanced oil recovery wells (6), injection wells (11), oil wells (79), gas wells (167), oil and gas wells (7), and service wells (9). These wells are producing, shut-in, or have been plugged and abandoned. Drilling depths ranged from 1,100 feet to 7,391 feet measured depth, with an average of 4,553 feet. The major producing fields were the Berryman, Borth, Cimarron Valley, Elkhart West, Flank, Greenwood Gas, Hugoton Gas Area, Interstate, Kinsler, Midway, Panoma Gas Area, Playa, Richfield, Taloga, Vilas, Walsh, and Wilburton (Figures 6a and 6b). The major productive area was the Hugoton Embayment in Baca County, Colorado (211 wells), and Morton County, Kansas (282 wells). The two primary producing formations reported were the Pennsylvanian Topeka Limestone of the Shawnee Group and the Pennsylvanian Morrow Formation. Operators with numerous wells drilled include Anadarko Production Company, City Service Oil Company, Davis Drilling Company, Horizon Oil and Gas Company, Pan American, and Thomas & Brewer.

1971 to 1980

From 1971 to 1980, 608 wells were drilled in the Study Area (Figure 12. The wells drilled and abandoned immediately were 169 of the 608 wells (72.20 percent success rate). The other 439 wells include gas wells (337), oil wells (43), oil and gas wells combined (2), injection or service wells (11), enhanced oil recovery wells (4), and gas storage wells (42). These wells are producing, shut-in, or have been plugged and abandoned. The ranges of total depths drilled are from 200 feet to 6,850 feet measured depth, with an average of 3,717 feet. The major producing fields include Boehm,

Greenwood Gas Area, Interstate, Panoma Gas Area (generally considered to be in the southwest corner of Morton County, Stonington, Vilas, and Walsh (Figures 6a and 6b). The majority of wells were drilled by Anadarko Production Company, Beams Robert J, City Services Oil Company, Colorado Interstate, Mobile Oil Corporation, Samson Oil Company, and Texas Oil and Gas Corporation. The primary producing formations reported are the Pennsylvanian Morrow Formation, Pennsylvanian Topeka Limestone of the Shawnee Group, Permian Council Grove Group, and the Permian Red Cave Formation of the Council Grove Group.

1981 to 1990

From 1981 to 1990, 596 wells were drilled in the Study Area (Figure 12). Wells drilled and abandoned were 193 of the 596 wells (67.62 percent success rate). The remaining wells are gas wells (249), oil wells (90), gas storage wells (22), enhanced oil recovery wells (8), oil and gas combined (13), and injection/service/other wells (21). These wells are producing, shut-in, or have been plugged and abandoned. Total depth drilled ranges from 900 feet to 7,050 feet measured depth (4,376 feet average). Major operators include Anadarko Petroleum Corporation, Cities Services Oil and Gas Corporation, Colorado Interstate, Hawkins Oil and Gas Incorporated, Ladd Petroleum Corporation, Oxy USA Incorporation, Patrick R. J. Operating Company, Samson Oil Company, and TXO Production Corporation. The primary producing formation reported include the Pennsylvanian Morrow Formation, Pennsylvanian Lansing Group, Pennsylvanian Topeka Limestone of the Shawnee Group, Permian Council Grove Group, Permian Red Cave Formation of the Council Grove Group, and the Permian Chase Group. Again, the Hugoton Embayment area saw the preponderance of drilling.

1991 to 2000

From 1991 to 2000, there were 531 wells drilled in the Study Area (Figure 12). One hundred twenty seven of the 531 wells were drilled and abandoned initially (76.08 percent success rate). The remaining wells are gas wells (310), oil wells (30), oil and gas combined (17), gas storage wells (23), enhanced oil recovery wells (10), and injection or other wells (14). These wells are producing, shut-in, or have been plugged and abandoned. Total depth drilled ranges from 50 feet to 7,010 feet measured depth (4,093 feet average). Primary operators during this period include Amoco Production Company, Anadarko Petroleum Corporation, Colorado Interstate, Energy Alliance Company, Harris Oil and Gas Company, Mobile Oil Corporation, Oxy USA Incorporated, and Richfield Gas Storage. The primary producing formations reported were the Pennsylvanian Morrow Formation, Pennsylvanian Topeka Limestone, Pennsylvanian Wabaunsee Group, Permian Red Cave Formation of the Council Grove Group, Permian Chase Group, and the Permian Herington Limestone of the Chase Group. The wells in this period produce almost entirely from the Hugoton Embayment in Baca County, Colorado, and Morton County and Stevens County, Kansas.

2001 to 2010

From 2001 to 2010, there were 253 wells drilled in the Study Area (Figure 12). Of the 253 wells drilled, 78 were drilled and abandoned (69.17 percent success rate). The remaining wells are gas wells (115), oil wells (27), oil and gas wells (13), enhanced oil recovery wells (5), and injection or other wells (15). These wells are producing, shut-in, or have been plugged and abandoned. Total depth ranges from 1,285 feet to 8,138 feet measured depth (4,820 feet average). Major operators include Anadarko Petroleum Corporation, Dominion Oklahoma Texas Exploration and Production, EOG Resources Incorporated, Nadal & Gussman LLC, Oxy USA Incorporated, and Presco Western LLC. The primary producing formations reported are the Pennsylvanian Morrow Formation, Pennsylvanian Topeka Limestone, Pennsylvanian Wabaunsee Group, Permian Council Grove Group, and the Permian Chase Group. All wells were drilled in the Hugoton Embayment in Baca County, Colorado and Morton County and Stevens County, Kansas.

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.

Drilling and Completion Activity

Through January 1, 2011 there have been 3,507 well locations spudded or completed (plus five applications to drill new wells) in the Study Area (IHS Energy Group, 2011; Colorado Oil and Gas Conservation Commission, 2011; and Kansas Geological Survey, 2011). In the Colorado portion of the Study Area (Figure 2a) there are 981wells with 62 wells (6.32%) located on Forest Service managed oil and gas minerals within the Comanche National Grassland, 145 wells (14.78%) located on other oil and gas minerals within the Comanche National Grassland, 20 wells (2.04%) on Bureau of Land Management oil and gas minerals outside the Grassland, 16 wells (1.63%) on Department

of Defense managed oil and gas minerals outside the Grassland, and 738 wells (75.23%) on other oil and gas minerals outside the Grasslands

In the Kansas portion of the Study Area (Figure 2b) there are 2,526 wells with 554 wells (21.93%) located on Forest Service managed oil and gas leases within the Cimarron National Grassland, 1,853 wells (73.36%) located on other lands within the Cimarron National Grasslands and 119 wells (4.71%) on other oil and gas minerals outside the Grassland.

Through January 1, 2011 there were 1,770 well locations spudded or completed (plus five applications to drill new wells) still in an active status in the Study Area (IHS Energy Group, 2011; Colorado Oil and Gas Conservation Commission, 2011; and Kansas Geological Survey, 2011). In the Colorado portion of the Study Area (Figure 9a) there are 267 active wells with 17 wells (6.37%) located on Forest Service managed oil and gas minerals within the Comanche National Grassland, 145 wells (8.99%) located on other oil and gas minerals within the Comanche National Grassland, four wells (1.5%) on Bureau of Land Management oil and gas minerals outside the Grassland, no wells on Department of Defense managed oil and gas minerals outside the Grassland, and 222 wells (83.15%) on other oil and gas minerals outside the Grassland.

In the Kansas portion of the Study Area (Figure 9b) there are 1,503 active wells with 297 wells (19.76%) located on Forest Service managed oil and gas leases within the Cimarron National Grassland, 1,166 wells (77.58%) located on other lands within the Cimarron National Grassland, and 40 wells (2.66%) on other oil and gas minerals outside the Grassland.

Of the 1,770 active status wells shown on Figures 9a and 9b, their well type and present status is:

- Location Filed 5 wells,
- Gas – Producing 1,154 wells,
- Gas – Shut-In 145 wells,
- Oil – Producing 31 wells,
- Oil – Shut-In 188 wells,
- Oil & Gas – Producing 31 wells,
- Oil & Gas – Shut-In 20 wells,
- Gas Storage – Active 38 wells,
- Gas Storage – Shut-In 1 well,
- Gas Storage – Injector 29 wells,
- Gas Storage – Observation 25 wells,
- Gas Storage – Shut-In Observation 2 wells,
- Injection – Active EOR 31 wells,
- Injection – Shut-In EOR 5 wells,
- Injection – Active 21 wells,
- Injection – Active Salt Water Disposal 35 wells,

- Injection – Shut-In Salt Water Disposal 1 well,
- Other – Shut-In 6 wells, and
- Water Supply 4 wells.

Some gas can be produced in association with oil producing wells and some oil can be produced in association with gas producing wells

About 72.78 percent (714 wells) of the 981 total wells have been plugged and abandoned in the Colorado part of the Study Area and 40.5 percent (1,023 wells) have been plugged and abandoned in the Kansas part of the Study Area. The 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 stratigraphic tests just 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 as disposal or service wells and were no longer needed for those purposes.

Deep Well Drilling

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 wells is very costly due to the extremely high temperatures and variable pressures and hard rock that can be encountered at great depth. No wells in the study area have been drilled in excess of 15,000 feet. The thickest sedimentary section in the Study Area occurs in the Hugoton Embayment, but even there the depth to Precambrian basement rock is less than 7,000 feet; thus, no deep well drilling is anticipated to occur in the Study Area (IHS Energy Group, 2011 and Rocky Mountain Association of Geologists, 1972).

Shallower Well Drilling: 5,000 feet and greater

Thirty-three percent of all of the wells drilled in the Study Area reached a total depth greater than 5,000 feet (1,164 of the 3,489 wells with an available depth measurement) (IHS Energy Group, 2011). Of these 1,164 wells the deepest well in the Study Area (the Anadarko Production Company, Low-D #2 well in the Cimarron National Grassland, Morton County, Kansas) reached a total depth of 7,391 feet. It penetrated the entire sedimentary section and bottomed in Precambrian granite. Figure 13 shows that most of these deeper wells have been drilled in the Hugoton Embayment and the Cimarron National Grassland. The majority of the productive wells greater than 5,000 feet in depth (57 percent) were completed for gas, 23 percent were completed for oil, five percent for oil and gas, and the remaining wells were injection, disposal, gas storage or service wells. Other than wildcats (218 wells) and the general "Hugoton Gas Area" (60 wells) the top ten fields with wells greater than 5,000 feet are as follows:

1. Richfield – 96 wells,
2. Greenwood – 90 wells,
3. Wilburton – 57 wells,
4. Kinsler East – 51 wells,
5. Kinsler – 49 wells,
6. Berryman – 37 wells,
7. Taloga – 31 wells,
8. Cimarron Valley – 31 wells,
9. Stirrup – 31 wells, and
10. Boehm (gas storage field) – 24 wells.

Productive formations at these depths are Cambrian (Arbuckle Group) through the Permian (Stone Corral Formation) in age. Most of the wells drilled to depths greater than 5,000 feet with reported production (mostly gas) targeted the Pennsylvanian Morrow Group formations (Keyes Formation – 17 wells; Morrow Group undifferentiated – 207 wells), Mississippian formations (Ste. Genevieve Formation – 6 wells; St. Louis Formation – 125 wells; undifferentiated Mississippian – 250 wells), and the Cambrian Arbuckle Formation (32 wells). It should be noted that 56 percent of these wells with total vertical depths greater than 5,000 feet report production from intervals shallower than 5,000 feet. Most of these wells produce from the Pennsylvanian Morrow and Kansas City Group formations.

Shallowest Well Drilling: Less than 5,000 feet

Most of the wells (2,324 wells, or 67 percent of the 3,489 total wells with an available depth measurement) in the Study Area have been drilled to total depths less than 5,000 feet (IHS Energy Group, 2011). Of the productive shallow wells, 78 percent were completed for gas, 14 percent for oil, one percent for oil and gas, and seven percent for injection, disposal, gas storage, or as service wells. As with the deeper wells, the majority of the wells drilled to depths less than 5,000 feet total depth in the Study Area have been drilled in the Hugoton Embayment and the Cimarron National Grassland (Figure 13). Other than wildcats (150 wells) and the general "Hugoton Gas" (546 wells) and "Panoma Gas" (178 wells) areas, the top ten fields with wells less than 5,000 feet are as follows:

1. Greenwood – 426 wells,
2. Interstate – 208 wells,
3. Walsh – 114 wells,
4. Taloga – 75 wells,
5. Flank (gas storage field) – 73 wells,
6. Vilas – 68 wells,
7. Campo – 45 wells,
8. Elkhart West – 37 wells,
9. Stonington – 34 wells, and
10. Boehm (gas storage field) – 32 wells.

As with wells drilled to depths greater than 5,000 feet, productive formations for these shallow wells range in age from the Cambrian (Arbuckle Group) through the Permian (Stone Corral Formation). Most of these wells with reported production (mostly gas) targeted the Permian Chase Group formations (237 wells), the Pennsylvanian Topeka Formation (264 wells), Lansing Group formations (79 wells), and Morrow Group formations (Keyes Formation – 8 wells; Morrow Group undifferentiated– 101 wells).

Summary of Current Drilling Techniques

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. 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 boreholes 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 Study Area. Where technology is shown to provide significant cost benefits, local operators will 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 boreholes also have the benefit of providing the operator with the option of drilling multiple boreholes from the same location, substantially reducing the surface disturbance, potentially avoiding environmentally sensitive areas, and reducing the number of facilities needed.

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

- 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 that lengthen overall drilling time on location, and/or
- increased torque and drag on borehole equipment.

In addition to increased costs, the risk of losing the borehole 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 borehole 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 additional costs and inherent risks involved in directional and horizontal drilling.

All but two of the Study Area oil and gas boreholes are recorded as having been drilled vertically (IHS Energy Group, 2011). The one directional well (Sandlin Oil Company, Mayberry 1-X located in section 10, Township 34 South, Range 41 West) was a sidetrack re-entry of an existing well bore. The original well, the Midwest Oil, Mayberry 1 well was completed in 1968 and produced 308,484 barrels of oil from the Morrow Group until final production in 1997. In 2004 the directional sidetrack was drilled also targeting the Morrow, but the well was plugged and abandoned with no production. The one horizontal well (EOG Resources, Inc, Andrews 8-1H located in section 8, Township 33 South, Range 39 West) was completed July 1, 2007 for gas with approximately 2,000 feet of horizontal wellbore in the Morrow. Initial production figures for this well are unavailable; however, July 2007 production is reported at 11.5 million cubic feet of gas. The most current production totals report 2.9 million cubic feet of gas produced in January, 2011 for a cumulative production of 186 million cubic feet of gas. No associated oil or water production has been reported.

Increased use of directional and horizontal boreholes is anticipated in the future, though no operators are known to have immediate plans to do so in the Study Area. However, since there are no known continuous accumulations (see Glossary) in the Study Area, it is more likely that such drilling will be primarily directional, not horizontal and employed for reasons related to surface disturbance and access rather than reservoir considerations.

Slimhole Drilling and Coiled Tubing

Slimhole drilling—a technique used to tap into reserves in mature fields—has not yet been used much in the Rocky Mountain Area. In eastern Colorado and western Kansas the technology has been used in the Niobrara unconventional gas play (see Glossary).

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. These types of rigs have been used in the Niobrara play in

eastern Colorado and western Kansas. In southwestern Kansas coiled tubing has predominantly been used to clean out the well after fracture treatment.

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, and
- reduced chance of damaging underpressured formations.

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

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

Light Modular Drilling Rigs and Pad Drilling

Now in production, new light modular drilling rigs can be more easily used in remote areas and are quickly disassembled and moved. Rig components are made with lighter and stronger materials and their modular nature reduces surface disturbance impacts. Also, these rigs reduce fuel use and emissions. Use of this type of rig in the Study Area is not likely in the near future. Other Rocky Mountain plays (North Dakota, western Wyoming, the Piceance basin in western Colorado, and shale plays in northeastern Colorado and eastern Wyoming which are just beginning to develop) have a higher priority for new rigs since more prolific reservoirs are being developed in those locations than reservoirs are known to be capable of within the Study Area.

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

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. Few fields in the Study Area are expected to meet these criteria. It is an important tool that can be used when drilling horizontal wells, so it could be used in those types of situations in the future. This type of drilling significantly reduces waste, shortens drilling time, cuts surface disturbance, and decreases power consumption and emissions.

Measurement-While-Drilling

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

Improved Drill Bits

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

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

Summary of Current Completion Techniques

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

the borehole. The casing also serves to protect sources of groundwater from contamination by oilfield fluids.

Some form of hydraulic fracturing (or fracing) 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. Proppant (usually slurry of sand and water) 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.

Water and sand make up about 98 percent of the fluid pumped into the formation, with other additives comprising the remaining two percent. Additives used in the fracturing process can be accessed by the public at http://www.fracfocus.org . The state of Colorado is presently working on a rule to require the disclosure of chemicals used in the hydraulic fracturing process by the end of 2011. Kansas does not presently have a rule requiring disclosure.

In Colorado, the majority of fluids used in the hydraulic fracturing process are recycled and no fluids are sent to wastewater treatment plants, which has been a concern in the eastern United States. For the small percentage of fluids disposed of, 60 percent goes into deep and closely-regulated waste injection wells, 20 percent evaporates from lined pits and 20 percent is discharged as useable water under permits from the Colorado Water Quality Control Commission. Kansas permits useable water discharge under their rules.

In Kansas, hydraulic fracturing was pioneered in 1947 by Stanolind Oil Company (Kansas Corporation Commission, 2011). In Kansas, this technology has been used on more than 57,000 wells, with about 600 wells hydraulically fractured annually while in Colorado the rate has been 2,888 wells hydraulically fractured annually (Interstate Oil and Gas Compact Commission, 2011). About 95 percent of new wells in Colorado are hydraulically fractured (Bureau files).

Only one horizontal borehole has been drilled to date in the Study Area. New types of horizontal fracturing technology will likely be used to stimulate these types of boreholes in the future. Development could be similar to that used to stimulate the Niobrara Shale in northeastern Colorado. For horizontal boreholes, multi-stage fracture stimulations could be used. In some cases the Energy Information Administration (2006a) has reported that once a formation has been fractured an uncemented pre-perforated liner is installed in the borehole.

Once a well is hydraulically fractured, the well is allowed to flow for a short period. This allows excess proppant and water used in the hydraulic fracturing process to be retrieved from the wellbore. Hydrocarbons will also be produced along with the water and proppant. Significant releases of methane may escape to the atmosphere during this phase, as well as other volatile organic compounds and hazardous air pollutants. Flaring is most often used to burn the methane, but flaring may release additional carbon dioxide and other pollutants to the atmosphere. Where air quality is a large concern, reduced emissions completions (also known as reduced flaring completions or green completions) can be used to capture the methane so that it is not released. Equipment is brought onto the well site to separate the gas from the proppant and water produced during this flow period and the recovered gas can then be delivered into a pipeline. Reduced emissions completions help reduce emissions of methane, as well as volatile organic compounds and hazardous air pollutants. These types of completions cannot be used for all new wells drilled. When wildcat, exploratory, and step out wells are drilled there is no nearby pipeline connection in place to take the gas that would be separated from the proppant and water.

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 United States have been rising in recent years. Annual Rocky Mountain operating costs rose to about 55,000 dollars per 12,000 foot well in 2005, as reported by Kim (2007).

Since 1990, most reserve additions in the United States (89 percent of oil reserve additions and 92 percent of gas reserve additions) have come from finding new reserves in old fields (U.S. Department of Energy, 1999). The U.S. Department of Energy (1999) reports that about half of new reserve additions in the United States are from more intensive development within the limits of known reservoirs. They report that the other half of reserve additions have come from finding new reservoirs in old fields and

extending field limits. Our review indicates that most reserve additions in the Study Area over the past 10 years have come predominately from development drilling (or infill drilling) of the oil and gas resource in the Hugoton Embayment part of the Study Area, with limited exploration for new oil and gas resources in this same area.

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

- 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. All nine units within the Study Area are reported as secondary recovery projects. See earlier unit agreement discussion for more information on these units and Figure 7 for their location.
- 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. This phase also has not been reported within the Study Area.

Oil and Gas Production

Historical oil and gas production for the Study Area was obtained for the Study Area from the IHS Energy Group (2011) database. This database does not contain production data from wells producing prior to the early 1960s. Oil production in the Study Area reached its peak in the early 1970s (Figure 14). This oil production appears to be tied to the increased drilling in the Study Area between 1961and 1980 that was tied to wells producing oil or oil and gas. This period is also tied to a peak in drilling in the Colorado part of the Study Area (Figure 10). Production has been in an overall decline since then, with occasional short production increases, the last one occurring in 2007. Cumulative oil production for the period shown in Figure 14 is approaching the 70 million barrel mark.

Gas production did not increase as quickly as oil production did in the late 1960s and early 1070s (Figure 15). There was an early peak in gas production in the late 1970s and then increasing production began in the late 1980s and peaked in 1994 and has been declining since then with more significant declines occurring in the last ten years. Since the late 1970s new wells have been primarily gas producers. Declines in gas production in recent years appear to be tied to reduced numbers of new wells drilled in both the Colorado part of the Study Area (Figure 10) and the Kansas part (Figure 11). The Hugoton Embayment portion of the Study Area has reached a mature stage of development, which has lead to the reduced number of wells drilled. Cumulative gas production for the period shown in Figure 15 has crossed the 600 million cubic feet mark in the past few years.

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).

Hydrogen sulfide has been reported from two wells in the Vilas field (Figure 6a) in the Colorado part of the study area at 0.04 and 0.06 mole percent (Bureau of Land Management, 2008). These two samples were in the Upper Pennsylvanian Topeka formation of the Shawnee Group (Figure 4). One well sample of gas containing hydrogen sulfide is reported from the Bureau of Land Management (2008) database. The well located in Section 11 of township 34 south, range 43 west contains 0.01 mole percent of hydrogen sulfide in a zone in the Upper Pennsylvanian Wabaunsee Group.

The Southwest Kansas H_2S and Low Pressure Task Force found that hydrogen sulfide “contamination is widespread throughout the gas producing regions of southwest Kansas” (Moline, 2006). They found that many wells in the greater Hugoton area are treated regularly. At the time of the report they were unable to accurately determine contamination levels in the producing reservoirs. Most wells with hydrogen sulfide have less than 30 parts per million, although those may be contaminant levels after treatment in most cases. Wells with hydrogen sulfide contamination include those that produce from the Chase Group, Council Grove Group and Topeka Formation.

Carbon Dioxide

Large percentages of carbon dioxide have been discovered during oil and gas exploration at a number of locations in the Study Area. In the region it has been found in high concentrations (Higley et al., 2007; Allis et al., 2001; Tremain, 1993; Sonnenberg and von Drehle, 1990; Bureau of Mines, 1968 and 1959; Clair and Bradish, 1956; Brainard and van Tuyl, 1954; Shoenfelt, 1938; and Dobbin, 1935) and at some locations it exceeds 98 percent. Past uses in the region have included dry ice sales, industrial uses, and for injection into oil reservoirs to enhance oil recovery.

Carbon dioxide can be found in gas wells of the Study area, with 79 of the 83 samples in the Colorado portion and 100 of 127 samples in Kansas (Bureau of Land Management, 2008). Only 18 well samples in Colorado exceed one mole percent carbon dioxide and none do in Kansas. At Playa field (Figure 6a) one gas sample recorded 1.8 mole percent from the Upper Pennsylvanian Topeka formation. Depth to this sampled interval was 3,354 feet. Seven gas samples from Model field (Figure 6a) reported 12.2 to 15.4 mole percent carbon dioxide, probably all tests were from the Lyons Sandstone (Lower Permian Sumner Group of Figure 4). Depth to these sampled intervals ranged from 900 to 1,091 feet. One abandoned well test, also in the Lyons Sandstone, reported 14.6 mole percent in section 30 of township 28 south, range 56 west (Figure 2a). Depth to this sampled interval was 1,015 feet.

Nine additional samples report 90 mole percent or more carbon dioxide. Three samples (96.6 to 97.6 mole percent) come from Nina View field (Figure 5a), with a nearby well reporting 95.9 mole percent. Depth to the three Nina View sampled intervals ranged from 485 to 880 feet and the nearby well depth was 125 feet. Five samples are from wells in township 29 south, ranges 50 and 51 west (Figure 2a) reported 91 to 99.4 mole percent. Depth to two sampled intervals was 210 and 425 feet and depth to two others was 4,332 and 4,466 feet with the fifth sample not reporting a depth. Data on formations sampled in these wells is not clear, but most likely samples the same Lyons Sandstone interval.

Only the wells at Model and Nina View field have produced (Figure 6a), although neither is now productive. Model field was at one time held as a helium reserve by the U.S. Government (see later discussion of the helium reserve). The discovery well was drilled in 1926 and 1927 (Clair and Bradish, 1956) and it produced from 1927 to 1940 (Higley et al., 2007). Carbon dioxide production was 777.121 million cubic feet. Nina View field production is reported from 1948 to 1965 with 53 million cubic feet of carbon dioxide produced (Higley et al., 2007). Carbon dioxide gas from Nina View field was processed at a plant in Bent County (Bureau of Mines, 1959) which produced dry ice and liquid carbon dioxide.

Helium Gas

Virtually all sampled wells (81 in Colorado and 127 in Kansas) report at least some small quantities of helium gas (Bureau of Land Management, 2008). In the region it has been found in high concentrations (Higley et al., 2007; Newell, 2007, Tremain, 1993; Clair and Bradish, 1956; Brainard and van Tuyl, 1954; Shoenfelt, 1938; and Dobbin, 1935) and at some locations it exceeds six percent. In Colorado the ranges have been:

- less than 0.5 mole percent 14 samples,
- 0.5 to 1.0 mole percent 45 samples,
- 1.0 to 2.14 mole percent 14 samples, and
- greater than 6.0 mole percent 8 samples.

In Kansas the helium ranges have been:

- less than 0.5 mole percent 72 samples,
- 0.5 to 1.0 mole percent 48 samples, and
- 1.0 to 1.7mole percent 7 samples.

Seven of the eight samples that exceed 6.0 mole percent were from Model field (Figure 62). Details about the Model field were discussed immediately above in the carbon dioxide discussion. Clair and Bradish (1956) estimated a helium reserve at Model field of 161.56 million cubic feet. The additional high test (8.8 mole percent) was from a well in section 30 of township 28 south, range 56 west (Figure 2a). This sample was from the Lyons Sandstone (Lower Permian Sumner Group of Figure 4) and depth to the sampled interval was 1,015 feet). In Kansas, the zones with higher percentages of helium included the Lower Permian Red Cave Sandstone and Chase Group, Upper Pennsylvanian Wabaunsee Group and Topeka, and the Lower Pennsylvanian Morrow Group.

Nitrogen Gas

Nitrogen gas forms a portion the gas stream in all wells in the Study Area that have published analyses (Bureau of Land Management, 2008). In the United States reserves with greater than five percent nitrogen are considered low-btu or "sub quality." See Glossary definition of British Thermal Unit (btu). In the Kansas part of the Study Area, 87 percent of 127 gas samples contain nitrogen of greater than five percent. Five percent of gas analyses in this area contain nitrogen gas at 40 percent or more of the gas stream, with the highest concentration at 52.56 percent.

In the Colorado part of the Study Area, 92 percent of 83 gas samples contain nitrogen of greater than five percent. Twenty-seven percent of gas analyses in this area contain nitrogen gas at 40 percent or more of the gas stream, with the highest concentration at 79.7 percent.

In fields with large quantities of nitrogen gas, it must be removed from the gas stream before it will be accepted into pipelines, which require at least 950 BTU per cubic foot.

The Kansas Geological Survey (2011b) has been working with industry to design and build low-cost nitrogen rejection plants for use in smaller volume fields with nitrogen gas so that they can be economically produced.

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. No acid gas reinjection wells are reported within the Study Area. Treating wells for hydrogen sulfide issues appears to be the preferred method to deal with that minor constituent rather than separating and reinjecting it.

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. Since oil wells are a limited portion of the total producing wells, artificial lift would not often be used on Study Area wells. Artificial lift could be used in the future if additional oil producing wells are discovered in the future.

Glycol Dehydration

In the Study 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. Historical water production for the Study Area was obtained for the Study Area from the IHS Energy Group (2011) database. This database does not contain production data from wells producing prior to the early 1960s. Annual water production was low for most of the period in which data is available (Figure 16). Annual water production in the Study Area began to significantly increase in the early 1990s and is tied to the significant increase in gas production that began at that time (Figure 15). Cumulative water production exceeded 50 million barrels in 2009.

Colorado allows produced water to be disposed of as follows:

1. Injection into a Class II well, permitted in accordance with Rule 325;
2. Evaporation/percolation in a properly permitted pit;

3. Disposal at permitted commercial facilities;
4. Disposal by road spreading on lease roads outside sensitive areas for produced waters with less than 3,500 milligrams per liter total dissolved solids when authorized by the surface owner;
5. Discharge into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder; and
6. Evaporation in a properly lined pit at a centralized Exploration & Production waste management facility permitted in accordance with Rule 908.

In Kansas, underground disposal of produced water quality fall under regulation 28-13.

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. No record of use of this equipment is available for the Study Area, but it certainly would be used where there was a concern about hydrogen sulfide in the produced hydrocarbons.

Vapor Recovery Units

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

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. The Flank gas storage field (Figure 7) does not lay on Forest Service managed lands. It is operated by Colorado Interstate Gas Company and has a capacity to store 19.89 billion cubic feet of gas (Energy Information Administration for EIA-191A). The Flank stores gas in the depleted Morrow Group “B” sandstone (Bolyard, 1990).

The Boehm gas storage field does lie within the Cimarron National Grassland. It is also operated by Colorado Interstate Gas Company and has a capacity to store 12.73 billion cubic feet of gas (Energy Information Administration for EIA-191A). Gas is stored in a depleted 12 foot thick sandstone reservoir (the Morrow Group “G”) and the Keyes sandstone at depths from 4,740 to 4,920 feet (Kansas Geological Survey, 2011).

PREVIOUS ASSESSMENTS OF OIL AND GAS RESOURCES

POTENTIAL GAS COMMITTEE

The Mid-Continent region covers all but the western most part of the Study Area. The Potential Gas Committee (2003) estimated 41.34 trillion cubic feet of natural gas for the Anadarko basin portion of the Mid-Continent.

ATLAS OF MAJOR ROCKY MOUNTAIN RESERVOIRS

The Atlas of Major Rocky Mountain Gas Reservoirs assessed oil and gas resources that covered only the Colorado portion of the Study Area. In this study Hemborg (1993) provided an overview of southeast Colorado then reviewed the Upper Pennsylvanian Topeka play, the Middle Pennsylvanian Cherokee Group play, and the Lower Pennsylvanian Morrow Group play. In addition, Tremain (1993) reviewed low-btu gas resources of Colorado, specifically the Model field within the Study Area.

U.S. DEPARTMENTS OF INTERIOR, AGRICULTURE, AND ENERGY

For oversight and regulatory purposes, the Department of Interior is required by the Energy Act of 2000 to report oil and gas resources underlying Federal lands. Restrictions and causes for delays are also required in the report. The Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development; Phase III Inventory—Onshore United States fulfilled this requirement (U.S. Departments of Interior, Agriculture, and Energy; 2003, 2006, and 2008). The Phase III report (2008) contains the most current Onshore United States inventory. The three reports do not cover this specific Study Area.

U.S. GEOLOGICAL SURVEY ASSESSMENTS

The U.S. Geological Survey is responsible for preparing the National Oil and Gas Resource Assessment for all provinces within the United States. They have prepared three overview reports that cover parts of the Study Area. Those assessments were done for:

- the Raton Basin Province;
- the Anadarko Basin Province,
- the Denver Basin Province; and
- the Las Animas Province.

These analyses provide the best future projections of the oil and gas resource in the Study Area. Very detailed summaries of these three assessments (including oil and gas resource calculations) can be found in Appendix I.

RAND CORPORATION ASSESSMENTS

The William and Flora Hewlett Foundation funded research assessments of natural gas and oil resources of the Rocky Mountain region. The assessments were performed by RAND Corporation, a non-profit research organization aspiring to improve policy and decision making. 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.

Issues were raised that the term "technically recoverable" was not inclusive of oil and natural gas that is actually producible. The report continues to state that "technically recoverable" resources (see Glossary for technically recoverable resources) do not include exploration and production costs, infrastructure and transportation costs, and environmental impacts (2003). The American Association of Petroleum Geologists' Secretary, Charles J. Mankin, dismissed this contention based on the fact that "viability" of future oil and gas production is more dependent on technology advances and public demand of resources than on cost (Nation, 2002). Therefore, the term and assessment of "technically recoverable" resources is still used today.

In "Assessing Gas and Oil Resources in the Intermountain West" (LaTourrette, p. 16, 2002b), a graph shows Rocky Mountain Region technically recoverable gas resources to be approximately 310 trillion cubic feet of gas. In contrast, the economically recoverable gas at the well head was approximately 60 trillion cubic feet of gas. This difference was emphasized in the RAND reports as to why "viable" resources should be reported instead of "technically recoverable" resources. Debra Knopman, a Senior Engineer at RAND, testified to the Subcommittee on Energy and Mineral Resources that their report is not meant to replace previous assessments, but their suggestions are meant to enhance, build upon, and more clearly define future reports (Knopman, 2002). The RAND Corporation incorporated their approach in the Greater Green River basin (LaTourrette, 2003). The lead author was contacted in August of 2006, and we asked for the information regarding the Greater Green River basin 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 Study Area.

OIL AND GAS OCCURRENCE POTENTIAL

We are using Bureau established criteria to use in rating the oil and gas occurrence potential of lands studied for an Environmental Impact Statement to be prepared for each Study Area. This rating is based on guidance outlined in Bureau of Land Management Handbook H-1624-1 which states:

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

- HIGH: Inclusion in an oil and gas play as defined by the USGS [U.S. 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, we consider that the Study Area lands have high, medium, or low potential for the occurrence of oil and gas as shown in Figure 17. Parts of the Study Area within the Raton basin, the Denver Basin, and the Anadarko basin provinces are contained within specific plays or assessment units (see Glossary) designated by the U.S. Geological Survey (see Appendix 1 for details of these provinces). These areas meet the criteria for a classification of high occurrence potential. Shows of hydrocarbons have been encountered in exploratory wells in 10 townships. These shows indicate indirect evidence that hydrocarbon reservoirs could be present and have been assigned a medium occurrence potential. The rest of the Study Area was assigned a low occurrence potential for hydrocarbons.

Wells at Model and Nina View fields are also plotted on Figure 17. These wells have been reported to contain carbon dioxide gas and or large volumes of non-hydrocarbon gases. In addition, analyses of gas from other wells in the Colorado portion of the Study Area indicate the presence of carbon dioxide and helium gases (see previous discussion of these two resources). Although no wells in the Colorado portion of the study area presently recover these gases for sale, there is some small potential for exploration and development of these resources during the analysis period.

PROJECTIONS OF FUTURE OIL AND GAS ACTIVITY 2011-2030

The Energy Information Administration (2009c) estimates that over the next two decades (through 2030):

- United States energy consumption will grow at an average annual rate of 0.5 percent, with liquid fuels growing at 0.1 percent and natural gas growing at 0.2 percent
- future natural gas supply will grow at an annual rate of 0.9 percent
- United States oil imports will decrease at an annual rate of 1.5 percent and natural gas imports will decrease at an annual rate of 2.6 percent
- price of natural gas will increase at an annual rate of 1.2 percent (in 2007 dollars)
- carbon dioxide emissions will remain the same from petroleum and will grow at an average annual rate of 0.3 percent for natural gas.

The above projected increases in energy demand and in gas prices indicate continued industry emphasis on increasing natural gas supplies and searching for additional natural gas supplies in the Study Area. Much of the Study Area oil and gas supply growth is expected to come from continued development of the oil and gas resource and new reservoir discoveries potentially coming from exploration to extend the limits of current plays in the assessment units identified by the U.S. Geological Survey as previously discussed and in Appendix 1.

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

Gas Prices

Data for Figures 18 and 19 (historical and projected future natural gas prices for Colorado and Kansas, respectively) were obtained from the Energy Information Administration (2011a). The Energy Information Administration price projection data is an average for Lower 48 Wellhead Prices and is made in 2008 dollars. Historical prices are in nominal dollars.

Beginning in 1985, wellhead gas prices in Colorado began to decline from a high of $3.43 per thousand cubic feet seen in 1984. By 1995, gas prices had decreased to $0.95 per thousand cubic feet -- less than a third of the 1984 prices. 1996 marked the beginning

of a general increase in natural gas prices in Colorado. 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 -- up nearly 800 percent from their 1991 low. Colorado wellhead prices declined sharply from 2005 to 2007 ($4.57 per thousand cubic feet), peaking again in 2008 at $6.94 per thousand cubic feet. As world economies struggled in 2009, Colorado wellhead gas prices fell again to $3.21 per thousand cubic feet, but have in recent months begun to recover.

Wellhead natural gas prices in Kansas followed similar historical trends. In the 1980s and 1990s, Kansas wellhead prices generally remained below $2.00 per thousand cubic feet with the exception of 1997 during which Kansas saw an average wellhead price of $2.05 per thousand cubic feet. As in Colorado, wellhead prices in Kansas had increased substantially by 2005. An average of $6.51 per thousand cubic feet in 2005 represents a 261 percent increase since 1999. Peak prices were seen in 2008 at $6.85 per thousand cubic feet, dropping sharply in 2009 to an average of $3.16 per thousand cubic feet.

Adam Sieminski, Chief Energy Economist for Deutsche Bank AG predicted that U.S. natural gas prices (Henry Hub) would average 7 dollars per thousand cubic feet through 2012 (Sieminski, 2007). Kevin Petak, Vice President, Gas Market Modeling for ICF International projected that Henry Hub (near the town of Erath in southern Louisiana) prices will average between 6 and 8 dollars per thousand cubic feet in the long-term (to 2025) (Petak, 2007). These projections were made during the steep rise in petroleum prices that began in 2004 and culminated with the rapid decline in prices in the second half of 2008. Since that time, global petroleum prices have seen a gradual recovery and Sieminski projects that by 2015 U.S. natural gas prices will reach 6 dollars per thousand cubic feet (Deutsche Bank, 2011). However, ICF International's long-term projections (to 2035) have not changed substantially. U.S. natural gas prices are still projected to average between 6 and 7 dollars per thousand cubic feet from 2021 through 2035 (Petak, 2010).

The Energy Information Administration 2011 Annual Energy Outlook projects that natural gas prices will rise gradually from their recent 2009 low (Energy Information Administration, 2011b). Through 2035, prices are projected to rise at a gradual rate (2.1 percent annually) reaching an estimated $6.42 (2009 dollars) per thousand cubic feet in 2035 (a 20 percent decline from the 2010 Annual Energy Outlook projections). While the recent combination of growing demand and limited supply had created market tightening and led to higher gas prices and price volatility, the Energy Information Administration predicts that natural gas prices in the long term will be significantly lower than previously projected due to the increase in recoverable shale gas resources (National Petroleum Council, 2003; Energy information Administration, 2011b). Domestic shale gas technically recoverable unproved reserves more than doubled from the 2010 to 2011 projections, and are estimated to be 827 trillion cubic feet; likewise, projected domestic shale gas production by 2035 is almost double that projected in the 2010 report, and is expected to account for over 47 percent of the total U.S. natural gas production. Increased domestic production is expected to drive an increase in natural gas exports to both Mexico and Canada totaling 2.8 trillion cubic feet by 2035.

The natural gas price projections allow for some generalizations concerning future gas drilling and production activity in the Study Area. If the Energy Information Administration gas price scenarios are accurate, the recent increased interest in natural gas in-fill field development in the Hugoton Embayment fields will likely continue, even though Colorado and Kansas prices dropped sharply in 2009 from their 2008 high. Since the gas fields in the Study Area are mature fields from non-shale gas formations, the level of drilling activity in the Study Area will probably be driven by future wellhead gas prices. Extensive exploration for new fields in the Study Area is not anticipated.

Total U.S. natural gas consumption in 2008 was 21.35 trillion cubic feet according to the Energy Information Administration's 2011 Annual Energy Outlook (Energy Information Administration, 2011b). Due mostly to an increase in industrial use over the projection period, natural gas consumption is expected to continually increase through 2035 resulting in an overall annual growth of 0.6 percent from 2009 through 2035. Increases in future natural gas production, to accommodate projected increased demand, are anticipated to come partly from the Rocky Mountain area, in particular shale gas resources. However, according to the U.S. Geological Survey's oil and gas assessments of the region, no continuous oil or gas assessment units overlie the Study Area. It is therefore not anticipated that any shale gas exploration or production will occur in the Study Area during the planning period, though the addition of shale gas reserves elsewhere in Rocky Mountains will likely influence wellhead gas prices throughout the region.

Oil Prices

In documentation submitted in support of his testimony before the U.S. House of Representatives Select Committee on Energy Independence and Global Warming, Sieminski (2008) stated that "our [Deutsche Bank] forecast for next year is that oil prices should average about $105/barrel," and that "for the longer term... prices will settle toward the cost of marginal supply, or $85/barrel..." While recent world events have seen oil prices fall from a high of over $145 per barrel (Daily Cushing, Oklahoma West Texas Intermediate crude oil spot price free on board) in July, 2008 to a low of less than $35 per barrel in February, 2009, it is likely that Sieminski's averages will approximate actual trends. Indeed, even with the volatility seen in prices throughout 2008, the average price for light sweet crude in 2008 was approximately $100 per barrel (Energy Information Administration, 2010a). Even with the exceptionally volatile crude oil prices since 2008, Sieminski’s recent medium-term price projections have not changed substantially. Average U.S. West Texas Intermediate crude oil prices are projected to average between 96 and 98 dollars per barrel through 2014 (Deutsche Bank, 2011).

Data for Figures 20 and 21 (historical and projected crude oil prices for Colorado and Kansas, respectively) were obtained from the Energy Information Administration (2011a). The data are projected averages of imported Low Sulfur Light Crude Oil prices and are made in 2009 dollars. Historical prices are in nominal dollars and show the historic volatility that has occurred in crude oil prices in the Study Area.

In general, the trends seen in wellhead gas prices in Colorado have been mirrored in Colorado crude oil prices though with slightly less volatility due to more consistent supply and demand. Prices began declining in the early 1980s from a high of $35.69 in 1981 to a low of $12.56 in 1998. The significant climb seen in natural gas prices since 1999 is generally mirrored in crude oil wellhead acquisition prices in the Study Area, with the exception that the dual price spike seen in natural gas prices (2005 and 2008) shows as a single spike in oil prices (2008 only). 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 fell sharply in 2009 to an average of $52.33 per barrel, but have since rebounded to an average of $72.75 in 2010. The most recent data for 2011 shows a continued upward trend with average prices for the first two months of $82.31 per barrel.

Kansas oil prices tend to follow the same trends as those seen in Colorado, though with less disparity in the actual wellhead acquisition prices than seen in natural gas. Kansas prices saw a 1981 high of $35.80 per barrel followed by a gradual decline to $12.19 in 1998. Oil prices peaked in 2008 at an average of $92.08 per barrel, and fell in 2009 to $54.41. Kansas oil prices rebounded in 2010 to an average of $72.43 per barrel, and the first two months of 2011 have averaged $82.89.

The Energy Information Administration (2011b) projection of future prices predicts slightly lower world oil prices by 2035 than those presented in the 2010 Annual Energy Outlook. The 2011 report projects that domestic petroleum-based liquids consumption will trend slightly upward through 2035 (approximately 21.9 million barrels per day), due to increased use of and reliance on biomass and gas-to-liquids fuels and increases in fuel efficiency. However, worldwide demand will continually increase during the same time, driving world oil prices to higher levels. The Energy Information Administration 2011 reference case projects that world oil prices will begin to rise from 2009 levels (approximately $60 per barrel) as production in non-OPEC regions peaks, and continue rising to approximately $125 per barrel in 2035 (all prices in 2009 dollars). However, the caveat that world market volatility causes uncertainty in future projections applies perhaps more now than in any time in recent history. Such uncertainty is demonstrated in the 2011 report's low- and high-price case projections. These cases reflect a wide band of potential world oil price paths, ranging from approximately $50.07 per barrel in the low case to $199.95 per barrel in the high case by 2035 in 2009 dollars ($81.59 and $321.76 nominal dollars, respectively) (Energy Information Administration, 2011b).

Historically, exploration activity for oil in the Study Area has been low with only one in five wells completed for oil, and only 37 oil wells completed in the last ten years (2001-2010). Data from the U.S. Geological Survey's 2004 oil and gas assessment for the Raton Basin-Sierra Grande Uplift attributes no technically recoverable undiscovered oil to those Study Area lands in the Raton Basin-Sierra Grande Uplift (eastern most Study Area) (U.S. Geological Survey, 2008). The bulk of the 104 million barrels of undiscovered technically recoverable oil (see Glossary for undiscovered technically recoverable resource) included in the 2003 Denver Basin assessment is attributed to plays

outside of the Study Area such as the continuous Niobrara-Codell assessment unit in the Wattenburg and surrounding fields north of Denver, and Dakota Group conventional fields in northeast Colorado. The majority of the current oil production in the Study Area is produced from the Pennsylvanian Morrow (including the Keyes Formation) and Lansing groups (IHS Energy Group, 2011). These groups are each part of the Pennsylvanian Composite Total Petroleum System (see Glossary for total petroleum system) as defined in the U.S. Geological Survey's 2010 Anadarko Basin Province assessment (IHS Energy Group, 2011; U.S. Geological Survey, 2010). Less than 7.5 percent of any of the Pennsylvanian Composite Total Petroleum System's assessment units are included in the Study Area lands, and most of the oil produced from these formations is in slightly deeper portions of the basin outside of the Study Area in northwest Oklahoma. As with the continuous gas assessment units, no continuous oil assessment units overlie Study Area lands. All of this suggests that future oil well drilling activity in the Study Area will be minimal and likely focus on in-fill drilling of existing productive fields. Activity will depend strongly on sustained levels of higher oil prices, and could include enhanced oil recovery injection well drilling in attempts to recover stranded oil left from primary production.

LEASING

After initial fieldwork, research, and subsurface mapping (which frequently includes use of seismic data), leasing is often the next step in oil and gas development. Leasing may be based on speculation, with 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. These auctions are now held on the first Tuesday of the second month in each quarter. 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 (see Glossary for held by production). However, Federal leases have no such clause, allowing one well to hold an entire lease.

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 leased and bonus bids received. Forty-nine percent of the money earned from oil and gas leases on public domain (see Glossary) minerals in the Study Area goes to the State of Colorado or Kansas. 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 22 presents the locations of leased Federal oil and gas minerals within the Study Area. Presently there are about 15,400 acres leased for oil and gas on the Comanche National Grassland and about 69,300 acres on the Cimarron National Grassland. About 12,748 acres are leased on other Federal managed lands in the Colorado part of the Study Area.

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 Study Area, geologists and engineers in the oil and gas industry were approached for their input. Major oil and gas companies operating in the Study Area were contacted by letter and asked what development activity they anticipated during the next 20 years. We also contacted many of these companies by telephone (with the assistance of John Dow of the Forest Service), either a few days after the letters were sent, or in order to clarify information after replies were received. Minerals staff of the Forest Service's Pike and San Isabel National Forest and Cimarron and Comanche National Grasslands offices were consulted to get their ideas and input for our projections. In addition, minerals staff of the Bureau of Land Management's Royal Gorge Field Office were consulted to get their input on other Federal lands in the Study Area. Information obtained was compiled and used to help predict locations and amounts of future drilling activity within the Study 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 Oil and Gas Drilling Activity

For a base line, unconstrained reasonable foreseeable development projection (Rocky Mountain Federal Leadership Forum, 2004, page 13) we estimate that during the analysis period of 2011 through 2030, as many as 447 oil and gas wells will be drilled in the Study Area.

The estimated oil and gas development potential and drilling densities within the Study Area during the analysis period are shown in Figure 23. Estimated acres, number of townships, and percentage of the Study Area within each development potential classification type shown in Figure 23 are summarized in Table 2 for the Cimarron

National Grassland, Comanche National Grassland, and all other non Forest Service managed oil and gas mineral lands.

We estimate that **average** drilling densities per township (one township is about 36 square miles) during the analysis period will be:

- Very High >20 wells
- High 10 to 20 wells
- Moderate 5 to <10 wells
- Low 1 to <5 wells
- Very Low <1 well projected.

The higher potential parts of the Study area (Figure 23) are within the Hugoton Embayment and specific predictions for each township were predominately tied to future drilling interest of the oil and gas industry operating in the area. Areas of very low development potential received little to no interest by the oil and gas industry when solicited for this analysis. A limited number of wells (about six percent of the 447 wells projected) are projected in areas of very low potential. Only a few wells in these areas have been completed as productive (carbon dioxide or low-btu wells) by historical drilling and none presently still produce. Most of the townships in these very low development potential areas will not receive any drilling activity during the Analysis Period. If new field discoveries are made in any of these very low development potential areas, subsequent drilling density could increase in those areas immediately around a discovery. However, predicting a well density for such areas is not possible at this time.

Historically, about 67 percent of conventional wells have drilled to a depth of less than 5,000 feet, with the remaining 33 percent drilling to depths of more than 5,000 feet. Only six wells drilled deeper than 7,000 feet. We anticipate that future drilling depths remain within the historical ranges and percentages.

PROJECTIONS OF FUTURE OIL AND GAS PRODUCTION

While average natural gas and crude oil wellhead prices since 2002 have generally been higher in the Study Area than during the 1990's (Figures 18, 19, 20, and 21) they did not lead to significant increases in drilling (Figure 12) or increase production (Figures 14 and 15). This indicates that the Hugoton Embayment part of the Study Area is in a mature state of development. Drilling additional infill wells in the area and finding new reserves with exploratory drilling could slow the trend of production declines within the Study Area.

ESTIMATED FUTURE CONVENTIONAL OIL AND GAS PRODUCTION

As indicated above, we projected 447 oil and gas wells could be drilled within the Analysis Period of 2011 through 2030. Calculations of spudded wells and associated production for the Analysis Period were generated via analysis through the program scripting language, Octave. The constraints used for the well spuds for both conventional

wells and coalbed natural gas wells were cumulative values and historical trend. A historical cumulative of spudded well data generates a smoother curve from which yearly differences can be extracted to produce annual projected well counts. Decline curves were then generated for gas and oil for both the conventional oil and gas and coalbed natural gas analysis. The decline curves were then normalized and convolved with the historical spudded well counts to generate a best fit with the **historical** production of oil, gas. The normalized decline curves were then convolved with the projected spudded well counts to produce annual mean projected oil and gas production (Table 3) from wells that are projected to be drilled during the Analysis Period. Since projected well activity is expected to decrease over the Analysis Period from the number of wells drilled during the last twenty year period (Figure 12), we expect the oil and gas production will continue the overall decline shown in Figures 14 and 15. If future drilling activity does not meet or exceeds our projections then production will not occur at the rate projected.

POTENTIAL FUTURE CARBON DIOXIDE SEQUESTRATION ACTIVITIES

Carbon dioxide sequestration is a method of storing captured carbon dioxide gas, a greenhouse gas. The primary industrial sources of carbon dioxide include electrical power plants, oil refineries, chemical refineries, agricultural processing plants, cement works, and iron and steel production. Power and industrial plants, agricultural processing, chemical processing, and petroleum and natural gas processing (including refineries and sources associated with pipeline infrastructure) have been identified as the major industrial sources of carbon dioxide (U.S. Department of Energy, 2007). Of these sources, electrical power plants produce the most carbon dioxide by a substantial margin.

Within the Study Area and the region, the largest carbon dioxide emission sources are power plants, with only one plant (natural gas) located in Baca County, Colorado (Young et al., 2007) and other power plants near the Study Area in both Kansas and Colorado. Small amounts or carbon dioxide may be produced in association with oil and gas production from fields within the Study Area (see previous discussion of carbon dioxide in Study Area wells).

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, with only two of these occurring in the Study Area (U.S. Department of Energy, 2008 and 2010). Those formation types are:

- Mature 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 (see Glossary) is assumed to be nonpotable. The U.S. Department of Energy (2007) has identified oil and gas reservoirs within the Hugoton Embayment part of the Study Area that could be considered for sequestration.

- Unminable coal seams – Unminable coal seams are considered to be those that are too deep or too thin to be economically mined. The U.S. Department of Energy (2007) has not identified coals within the Study Area that would qualify.
- Saline formations – Saline formations suitable for carbon sequestration were defined in the U.S. Department of Energy (2008) 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. Saline rocks can 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 U.S. Department of Energy (2007) has identified the Study Area as containing saline formations with potential for carbon dioxide storage.

POTENTIAL OIL AND GAS SURFACE DISTURBANCE

Table 4 projects short-term and long-term disturbance associated with existing conventional oil and gas wells and projected drilling activity for 2011 through 2030. The method used to determine the number of new wells drilled during this period has been previously discussed. In addition, we assumed that:

- of the existing active wells,
    - none of the currently active gas storage wells or associated observation wells will be abandoned during the planning period,
    - none of the currently active secondary/enhanced oil recovery wells will be abandoned during the planning period,
    - twenty percent of the existing oil and gas wells active as of January 1, 2011 will be abandoned by the end of 2030, and
- the success rate of new oil and gas wells will average 70 percent (see previous discussion).

Acreage disturbance estimates are based on average well pad, access road, and pipeline disturbances of existing wells located in the Study Area and averages from applications for permit to drill (plats and maps) for projected new wells.

Table 4 shows our projection of 447 new exploratory and development wells that could be drilled in the Study Area from 2011-2030. Of the 447 projected new wells, 259 are projected to be drilled on Cimarron National Grassland lands and 78 on Comanche National Grassland lands. The remaining 110 wells are projected to be drilled outside of the USDA Forest Service managed lands. There are an additional 1,765 existing active wells of January 1, 2011 located in the Study Area, 1,459 of which are located on Cimarron National Grassland lands and 40 of which are located on Comanche National Grassland lands (IHS Energy Group, 2011). Table 4 also calculates associated acres of total short-term surface disturbance directly associated with existing active wells and all new wells drilled during the planning period. There are approximately 1,200 acres of existing short-term surface disturbance associated with wells existing as of January 1, 2011 (992 acres of Cimarron National Grassland and 27 acres of Comanche National

Grassland). Approximately 2,043 acres of new short-term surface disturbance (1,184 acres of disturbance on Cimarron National Grassland lands and 356 acres on Comanche National Grassland lands) could occur if all projected new wells are drilled. Approximately 3,243 acres of new (2,043 acres) and existing (1,200 acres) short-term surface disturbance (2,176 acres of disturbance on Cimarron National Grassland lands and 384 acres on Comanche National Grasslands land) could thus occur in the short term.

Table 4 further calculates new producing wells remaining in production after all new exploratory and development wells are drilled and all dry holes are abandoned and reclaimed (313 total new producing wells with 181 of those on Cimarron National Grassland lands, and 55 on Comanche National Grassland lands). It is projected that 1,438 of the active existing wells as of January 1, 2011 will still be in production by the end of the planning period (1,181 on Cimarron National Grassland lands and 32 on Comanche National Grassland lands). Also shown in Table 4 is unreclaimed associated acres of total surface disturbance (long-term disturbance) directly associated with all remaining wells. Approximately 1,314 acres of unreclaimed surface disturbance associated with projected new wells (761 acres of unreclaimed Cimarron National Grassland lands and 229 acres of unreclaimed Comanche National Grassland lands) and 978 acres of unreclaimed surface disturbance associated with active existing wells as of January 1, 2011 still in production at the end of the planning period (803 acres of unreclaimed Cimarron National Grassland lands and 22 acres of unreclaimed Comanche National Grassland lands) could remain in the long-term. Total unreclaimed long-term surface disturbance is projected to be as much as 2,292 acres, with 1,565 acres of unreclaimed Cimarron National Grassland lands and 251 acres of unreclaimed Comanche National Grassland lands.

SUMMARY

For our base line projection we analyzed the oil and gas resource within the Study Area, discussed types of future development that may occur, estimated the development potential for each type of resource, and projected base line activity levels for the Analysis Period 2011 through 2030. We projected that as many as 447 oil and gas wells could be drilled during this period. Our forecast of annual oil and gas production for 2011 through 2030 is presented in Table 3. Short-term and long-term surface disturbance associated with existing wells and with future projected wells is presented in Table 4 for all lands and for those in the Cimarron National Grassland and in the Comanche National Grassland.

APPENDIX 1 – U.S. GEOLOGICAL SURVEY ASSESSMENTS OF UNDISCOVERED TECHNICALLY RECOVERABLE OIL AND GAS RESOURCES WITHIN THE PIKE AND SAN ISABLE NATIONAL FORESTS STUDY AREA

INTRODUCTION

The U.S. Geological Survey has published a number of resource assessments of undiscovered oil and gas resources that cover parts of the Cimarron and Comanche National Grasslands Study Area. The "1995 National Assessment of United States Oil and Gas Resources" scientifically estimated the amount of crude oil, natural gas, and natural gas liquids (see Glossary) that could be added to proved reserves (see Glossary for 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. Four of those provinces, the Raton Basin-Sierra Grande Uplift, Anadarko Basin, Denver Basin, and Las Animas Arch, lie within the Study Area. Figure A1-1 shows the location of the four provinces within the Study Area. The Raton Basin-Sierra Grande Uplift and Denver Basin Province were assessed in the U.S. Geological Survey 1995 Assessment and the U.S. Geological Survey 2007 Assessment. The Las Animas Arch and Anadarko Basin Provinces are currently being updated and combined for a new review likely released in 2012. The factsheet and shapefiles for the new assessment are available online at http://pubs.usgs.gov/fs/2011/3003/.

Recently, the U.S. Geological Survey revised their methods for preparing oil and gas resource assessments. Twenty-eight basins have been reassessed or will be re-assessed since the 1995 report. The U.S. Geological Survey used the new method to update their quantitative estimate of undiscovered oil and gas resources for the Raton Basin-Sierra Grande Uplift, Denver Basin, and the combined Las Animas Arch and Anadarko Basin Provinces. Summaries of each basin province, total petroleum system, assessment unit, and play within the Study Area is presented below by using a combination of the 1995 assessment, if applicable, and the newest available assessment report. Figure A1-1 shows the basin province boundaries. All information was taken from the U.S. Geological Survey Assessments and considered for the Study Area. For more detailed information, refer to the complete reports published by the U.S. Geological Survey (http://energy.cr.usgs.gov/oilgas/noga).

RATON BASIN PROVINCE ASSESSMENT

The Raton Basin Province is in southern Colorado and northern New Mexico. It is located in the Study Area (Figure A1-1). The Raton Basin is bound on the west by the Sangre de Cristo Mountains. The Wet Mountains and Apishapa Arch bound the basin on

the north. The Sierra Grande Uplift limits the basin on the east. The Tucumcari Basin is the south boundary of the Raton Basin. The thickest section of sedimentary rock (approximately 16,000 to 20,000 feet) occurs along the basin axis. Groundwater flows from west to the east. The primary fracture trend is east-west (Higley et al., 2007). Thermal maturity ranges from 1.5 percent Ro in the center of the basin to 0.7 percent Ro on the boundary of the basin. Rocks older than Triassic age are overmature (2007). One exception is the Pennsylvanian-Permian Sangre de Cristo Formation, which is gas and carbon dioxide productive at Bravo Dome. Another exception is the Permian Yeso Formation, which produced helium and nitrogen at Model Dome (2007). The composition of gas in the Cretaceous Vermejo Formation and Cretaceous-Paleocene Raton Formation is approximately 90 percent methane, 5 percent nitrogen, and 2 percent carbon dioxide (2007). Due to thermal maturity, the middle of the basin is more gas rich while the edge of the basin is in the oil generation window. Coal beds are approximately 4,100 feet deep in the northern Raton Basin, but generally 1,200 feet deep over the larger portion of the basin (Keighin, 1995). The only assessment unit from the Raton Basin Province which extends into the Study Area is the Jurassic-Lower Cretaceous Reservoirs Assessment Unit, which is a conventional accumulation (see Glossary).

Total Petroleum System and Assessment Unit Summaries

In their newest assessment (written in 2005 and published in 2007), the U.S. Geological Survey divided the Raton Basin Province into "Total Petroleum Systems" and "Assessment Units" (see Glossary definitions) rather than "Plays." Summaries of the Total Petroleum System and Assessment Unit are provided below.

Jurassic-Cretaceous Composite Total Petroleum System

The Jurassic-Cretaceous Composite Total Petroleum System is in the southern area of the Study Area (Figure A1-2). Average resources in the total petroleum system (Table A1-1 and A1-2) are 615.09 billion cubic feet of gas and 24.58 million barrels of natural gas liquids (Higley, 2007). The one assessment unit in this total petroleum system and within the Study Area is the Jurassic-Lower Cretaceous Reservoirs Assessment Unit. Below is a summary of this assessment unit.

Jurassic-Lower Cretaceous Reservoirs Assessment Unit

The Jurassic-Lower Cretaceous Reservoirs Assessment Unit is in the western portion of the Study Area (Figure A1-2). There is a minimal amount of the assessment unit that is within the Study Area (0.13 percent). Undiscovered accumulations assessed for the 2007 report can be viewed in Tables A1-1 and A1-2. Formations within the assessment unit are from the base of the Jurassic Entrada Sandstone through the top of the Cretaceous Greenhorn Limestone Member of the Cretaceous Benton Formation (Higley, 2007). The Cretaceous Graneros Shale Member of the Cretaceous Benton Formation is the source rock in the Assessment Unit. In contrast, the 1995 report stated the source was shale and coal within the Cretaceous Purgatoire Formation and Cretaceous Dakota Sandstone and overlying shales (Keighin, 1995). Thermal blanket effects of coal added thermal maturity in the Raton Basin (2007). Reservoir rocks include the Jurassic Entrada Sandstone,

Jurassic Morrison Formation, Lower Cretaceous Purgatoire Formation, and Lower Cretaceous Dakota Sandstone. The Lower Cretaceous Dakota Sandstone has the greatest potential for natural gas resources in the Assessment Unit, partly due to close proximity to the source. The Lower Cretaceous Dakota Formation in the south half of the Raton Basin is unfavorable due to widespread presence of water which is in communication with other formations. The Jurassic Wanakah Formation and Lower Cretaceous Graneros Shale act as seals. Traps include structural anticlines, lenticular and fluvial sandstone stratigraphic traps, and interbedded shale (Keighin, 1995). The Cretaceous Codell Sandstone Member of the Cretaceous Carlile Shale is in fact the only formation in the entire Raton Basin Province boundary to have produced oil. Jurassic Morrison Formation and Lower Cretaceous Dakota Sandstone in the Wagon Mound field produced 97 million cubic feet of gas from 1940 to 1981. While this field is in New Mexico, it shows the hydrocarbon productivity of these formations in the Raton Basin.

ANADARKO BASIN PROVINCE ASSESSMENT

The updated Anadarko Basin Province fact sheet and shapefiles are available online. The factsheet was available to the public January, 2011. The updated report combines the Anadarko Basin Province and the Las Animas Arch into one province boundary. The province assessment units can be seen on Figures A1-3 and A1-4. Undiscovered accumulations assessed for the 2011 report can be viewed on Table A1-3. Since the report has yet to be published, the discussion below will focus on the 1995 report.

Four states are included in the Anadarko Basin Province: Kansas, Oklahoma, Colorado, and Texas. Thermal maturity increases from north to south. In concurrence, depth of strata increases from north to south (Henry and Hester, 1995). Gas is the primary hydrocarbon produced. Stratigraphic traps are ubiquitous. Bounding the basin is the Wichita-Amarillo Uplift, Cimarron and Las Animas Arches, Central Kansas Uplift, Pratt Anticline, Nemaha Uplift, and Southern Oklahoma fold belt. First production began in 1917 in Cement Field (Nzlegacy, 2004). The basin is well explored.

Sixteen of the 1995 Anadarko Basin Province plays are in the Study Area. Each play contains portions in the Study Area (Figures A1-5 through A1-8). Discussed below are key aspects of each play pertaining to the Study Area. Undiscovered accumulations assessed for the 1995 report can be viewed in Tables A1-4 and A1-5.

Play Summaries

Sixteen play areas (see Glossary for play area) in the “1995 National Assessment of United States Oil and Gas Resources” for the Anadarko Basin Province are within the Study Area. All plays are considered conventional play areas. 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 contains oil and gas accumulations having hydrocarbon-water contacts and seals that hold or trap hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices.

Uppermost Arbuckle Play

The Uppermost Arbuckle Play covers approximately 87 townships in the Study Area (Figure A1-5). These townships are from township 50 west to the easternmost Study Area boundary.

The Uppermost Arbuckle Play is a self-sourced, partially independent petroleum system. Limestone and dolomite of the Ordovician Arbuckle Group are the primary reservoirs. Shale and organic rich rocks of the Ordovician Simpson Group and Ordovician Arbuckle Group source the reservoirs. Low-porosity zones in the Ordovician Arbuckle Group, or overlying low-porosity rocks, seal the system. Structural traps include the Nemaha Uplift, Pratt Anticline, and Central Kansas Uplift.

Exploration has occurred predominantly in the upper portion of the Ordovician Arbuckle Group. Bradbridge field, located in Kansas, has the largest estimated ultimate recovery of gas, 27 BCF. Garber field, discovered in 1916 and located in Oklahoma (Boyd, 2009), was the first field in the play. Drilling is close to structures. Uncertain to low potential was forecasted for this play.

Internally sourced Arbuckle Play (Hypothetical)

The Internally sourced Arbuckle Play shares the same boundary as the Uppermost Arbuckle Play (Figure A1-5). Due to sparse well control, this play provides little information. Major hydrocarbon reservoirs are unknown. Source rocks are not abundant and of poor quality. Found reservoirs include limestone and dolomite in the Cambrian-Ordovician Arbuckle Group. Reservoir thickness increases from northwest to the south (300 feet to 4,000 feet). Reservoirs have highly variable quality. Oil is expected in the northwest (Kansas and possibly part of Colorado in the Study Area) where the Cambrian-Ordovician Arbuckle Group is buried at shallow depths. Gas is expected where the Cambrian-Ordovician Arbuckle Group is buried deeper in the south. Production as of 1995 was primarily in the north and east of the play. While the play is hardly explored, low potential to find undiscovered resources is predicted (Henry and Hester, 1995). See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Simpson Oil and Gas Play

The Simpson Oil and Gas Play shares a boundary in the Study Area with the Cambrian-Ordovician Arbuckle Group Plays (Figure A1-5). The Garber Field (Oklahoma) was discovered in 1916. The Garber Field produces from the Ordovician Simpson Group. Total hydrocarbon resource from the field was expected to be seven billion cubic feet of gas. The earliest wells drilled were following structures such as the Nemaha Uplift, Pratt Anticline, and the Kansas Uplift. The traps are structural anticlines, faulted anticlines, and stratigraphic facies changes. Source rocks include the Upper Ordovician Sylvan Shale, Cambrian-Ordovician Arbuckle Group, and the Ordovician Simpson Shale. The Devonian Woodford Shale may be a source, but it is unlikely since it is from Devonian

aged rocks. Reservoir rocks include good quality sandstone with interbedded shale in the Ordovician Simpson Group. Potential to find undiscovered resources is low (Henry and Hester, 1995). See Tables A1-4 through A1-5 for undiscovered resources for this play within the Study Area.

Viola Oil and Gas Play

The Viola Oil and Gas Play is in approximately 33 townships in the Study Area (Figure A1-5). Depth of the Ordovician Viola Limestone is approximately 4,000 feet in the Study Area. Reservoir thickness of the Ordovician Viola Limestone has a maximum thickness of 500 feet. Shale sources gas in the play from the Ordovician Simpson Group, Ordovician Sylvan Shale, and Devonian Woodford Shale. Traps include structural faulted anticlines. Sealing the reservoir is likely the Ordovician Viola Limestone or the Ordovician Sylvan Shale. Concentration of drilling is on the north and east boundaries of the province, which is outside the Study Area. The largest accumulation is an estimated ultimate recovery of 30 billion cubic feet of gas at the Union City field, Oklahoma. Both oil and gas are produced in this play. The potential for discovering new fields is low (Henry and Hester, 1995). See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Misener Oil Play

The Misener Oil Play is in the Study Area (Figure A1-6). The play boundaries are common with the Arbuckle Play areas and the Simpson Oil and Gas Play. The extents of the play are from the base of the Ordovician Simpson Group to the top of the Devonian Woodford Shale. The Middle and Upper Devonian Misener Sandstone is the reservoir rock in this play. It is 4,000 to 13,000 feet deep from north to south. The reservoir is good quality with a thickness range of 30 to 160 feet (Henry and Hester, 1995). Sourcing the oil in the reservoir are the Devonian Woodford Shale and the Ordovician Simpson Group. Stratigraphic trapping is predominant along with some combination traps. The main seal is the Devonian Woodford Shale. As of 1995, there was little production from the Misener Oil Play in the Study Area. Potential for new resource discoveries is low. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Lower Mississippian Stratigraphic Oil and Gas Play

The Lower Mississippian Stratigraphic Oil and Gas Play includes the Lower Mississippian Hannibal Shale, Lower Mississippian Gilmore City Limestone, Lower Mississippian Osage chert, Mississippian Meramec lime, Mississippian Warsaw Formation, Mississippian Salem Formation, and Mississippian Ste. Genevieve Formation. The play boundaries are shown in Figure A1-6. The play was discovered in 1938 by the Pleasant Valley field. Again, this play follows the east half of the Study Area. Reservoir rocks are limestone of the Lower Mississippian strata listed above. The Woodford Shale sources the reservoirs. Oil is more abundant than gas in this play. Traps include stratigraphic, structural, and combination. Major accumulations of this play are outside

the Study Area. The Sooner Trend is a major structural feature trapping oil and gas in this play. Glick field was the largest gas deposit having an estimated ultimate recovery accumulation of 722 billion cubic feet of gas (Henry and Hester, 1995). The potential to discover new resources is low. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Upper Mississippian Stratigraphic Gas and Oil Play

The Upper Mississippian Stratigraphic Gas and Oil play includes the Mississippian St. Louis Formation, the Mississippian Chester Group, the Mississippian Ste. Genevieve Formation, Mississippian Springer Formation, and the Devonian Woodford Shale. Strata from this play are present in the Study Area (Figure A1-6). Reservoir rocks include limestone from the Mississippian St. Louis Formation and Mississippian Chester Group. Source rocks are interbedded shales in the Devonian Woodford Shale and Mississippian Springer Formation. Trapping is primarily stratigraphic with some combination and structural. Seals are from overlying shales on carbonate or ooid sand bars. The play was discovered in 1921 by the Webb field (Henry and Hester, 1995). The largest gas accumulation in the play is the Mocane-Laverne field with an estimated ultimate recovery of 1.2 trillion cubic feet of gas. The largest oil accumulation has an estimated ultimate recovery of 44 million barrels of oil at the Big Bow Field (Henry and Hester, 1995). The potential to find new fields is moderate. The play is well explored. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Morrow Sandstone Gas and Oil Stratigraphic Play

The Pennsylvanian Morrow Group shales source the Morrow Group sandstones in the Morrow Sandstone Gas and Oil Stratigraphic Play. Porosity of the sandstone averages 13 percent with permeability at an average of 20 millidarcies (Henry and Hester, 1995). Sands were created from a valley fill beach, offshore bars, and deltaic deposits. Shales in the Morrow Group have total organic carbon contents up to 18 percent. In the Study Area, the Morrow Group shales have a lower thermal maturity than the rest of the play area. Trapping, as indicated by the play name, is of stratigraphic nature. The most productive portion of the play is in the center of the play, with decreasing productivity to the northeast and northwest. Gas is the primary hydrocarbon produced in this play. Oil accounts for about 30 percent of the hydrocarbon accumulations in this play. The play is less explored in Kansas and Colorado, compared to Texas and Oklahoma. There is moderate to good potential for future field discoveries. As described in the well history for this reasonable foreseeable development scenario, many wells drilled in the Study Area produce gas and oil from the Pennsylvanian Morrow Sandstone. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Atokan Limestone Stratigraphic Gas and Oil Play

The Pennsylvanian Atokan Group is the reservoir rock in the Atokan Limestone Stratigraphic Gas and Oil Play. The play is located in the Study Area (Figure A1-7). Reservoir quality is unsure in the northern portion of the play. Porosity averages 9

percent. The source is from shale in the Atoka Group and Morrow Group shales. In western Kansas and eastern Colorado, thermal maturity suggests an immature system with respect to oil generation. Combination traps are from 6,600 feet to 11,400 feet in depth (Henry and Hester, 1995). Seals include interbedded Atoka Group shale, dolomite, and anhydrite. There is minor production from this play in the in the Study Area (Tables A1-4 and A1-5). Of the production, gas is the only hydrocarbon produced. Historical exploration includes Lipscomb field with the largest known gas accumulation (estimated ultimate recovery of 50 billion cubic feet of gas) and Arnett field, the largest oil accumulation (estimated ultimate recovery of 13 million barrels of oil). Potential for discovery of new accumulations is low.

Lower Desmoinesian Stratigraphic Gas and Oil Play

The Lower Desmoinesian Stratigraphic Gas and Oil Play is shown in Figure A1-7 in the Study Area. The primary reservoirs are the Middle Pennsylvanian sandstone and limestone including the Burgess, Bartlesville, Red Fork, Skinner, Prue, Osborne, Pooler, Hart, and Charleston sands. Porosity averages eight percent and permeability is about 0.1 millidarcies (mD). Reservoirs are sourced from the Middle to Upper Pennsylvanian black shales. Total organic content ranges from zero to 18 percent with Type II and Type III kerogens (Henry and Hester, 1995). Traps are primarily stratigraphic with some structural traps. Historical Exploration remains in Oklahoma and Texas. Approximately 75 percent of existing fields are gas fields. The largest oil accumulation with an estimated ultimate recovery of 30 million barrels of oil is from the Cherokita Trend. The largest gas accumulation is the North Moorwood field with an estimated ultimate recovery of 1.5 trillion cubic feet of gas. In the Study Area, the petroleum system is not thermally mature, is of poor reservoir quality, and there are fewer sands in this play. Therefore, there is low potential for discovery of new resources in the Study Area. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Upper Desmoinesian Oil and Gas Play

From township 50 west, range 28 south, through township 50 west, range 35 south to the eastern boundary of the Study Area resides the Upper Desmoinesian Oil and Gas Play (Figure A1-7). The Pennsylvanian Marmaton Group and Pennsylvanian Deese Group limestone and thin shale beds are the reservoirs for this play. Thickness of the reservoir is from 175 feet to 1700 feet with 2 to 18 percent porosity. Shales from the Marmaton Group or other Pennsylvanian shales source the reservoir. Structural traps are predominant in the area. Oil plays are about three times more abundant than gas plays. Putnam oil field has the largest recorded accumulation in this play (estimated ultimate recovery of 65 million barrels of oil). South Lambert field has an estimated ultimate recovery of 123 billion cubic feet of gas, making it the largest gas accumulation in this play. As of 1995, there were as many as 40,000 to 64,000 well penetrations in this play (Henry and Hester, 1995). Potential for new undiscovered resources is low. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Lower Missourian Stratigraphic Oil and Gas Play

Figure A1-8 shows the Lower Missourian Stratigraphic oil and gas play within the Study Area. Sandstones from the Cleveland, Layton, Melton, Culp, Marchand, Medrano, Wade, and Briscoe sands, and Cottage Grove Sandstone are reservoirs for oil and gas accumulations. There are 27 oil accumulations and 25 gas accumulations in this play. The Upper Pennsylvanian shales source the play, but in Kansas and Colorado the source rocks are not thermally mature. This play has both combination and stratigraphic traps. Interbedded shales and mudstones seal oil and gas in their reservoirs. Long distance migration is thought to have partially charged the reservoirs. Elk City field has the largest oil accumulation in this play (estimated ultimate recovery of 110 million barrels of oil). Ellis Ranch field has the largest gas accumulation in this play (estimated ultimate recovery of 360 billion cubic feet of gas). There is limited potential to discover new resource accumulations in Kansas or Colorado due to low thermal maturity in the area (Henry and Hester, 1995). See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Upper Missourian Oil and Gas Play

The upper part of the Upper Pennsylvanian Lansing and Hoxbar Groups make up this play. Figure A1-8 shows the Upper Missourian Oil and Gas Play within the Study Area. Reservoir rock is limestone from the Lansing Group. Porosity averages 15 percent (Henry and Hester, 1995). Most of the oil and gas accumulations are in the northwest half of the play. Long distance migration helped source the play along with Pennsylvanian shales. The Lansing shale is thought to seal the play. Known major accumulations occur from 3,800 feet to 5,600 feet. This play is well explored (greater than 24,000 wells). Victory field is the largest oil accumulation (estimated ultimate recovery of 17 million barrels of oil). Southeast Falkner field is the largest gas accumulation in this play (estimated ultimate recovery of 28 billion cubic feet of gas). With so much exploration, there is low potential to find new undiscovered resource accumulations. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Lower Virgilian Sandstone Gas and Oil Play

The Lower Virgilian Sandstone Gas and Oil Play is within the Study Area (Figure A1-8). Formations in the Lower Virgilian Sandstone Gas and Oil Play include all Lower Virgilian Douglas and Vamoosa Group rocks. Sandstones and some carbonates from the Douglas and Vamoosa Group are the reservoirs in this play. Thickness of the reservoirs is from zero to 2,000 feet with a median porosity of 15 percent. The depositional environments are fluvial deltaic or submarine fans. Accumulations of oil and gas exist at depths from 4,300 feet to 8,500 feet. Thermally mature Pennsylvanian shales of Type II and Type III kerogens source this play (Henry and Hester, 1995). Combination, stratigraphic, and structural traps are present. Interbedded shales and possibly limestone beds seal the reservoir. The Mocane-Laverne field is the largest gas accumulation in this play with an estimated ultimate recovery of 1.1 trillion cubic feet of gas. Chickasha field

is the largest oil accumulation in this play with an estimated ultimate recovery of 71 million barrels of oil. While there are from 26,000 to 78,000 penetrations, there is a low potential to discover new accumulations in the north part of the play due to lack of thermal maturity in source rocks and poor reservoir quality development. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Upper Virgilian Stratigraphic Oil and Gas Play

The Upper Virgilian Stratigraphic Oil and Gas Play is in the eastern portion of the Study Area. The Upper Pennsylvanian Shawnee, Wabaunsee, and Admire Groups are the primary formations in the Upper Virgilian Stratigraphic Oil and Gas Play. These groups also constitute the reservoir. Limestone with oolitic and skeletal grainstone is the lithology of the reservoir. Leaching occurred in the limestone, which created secondary porosity. The median porosity is 13 percent with a range of 8 to 17 percent (Henry and Hester, 1995). From 3,000 feet to 6,100 feet, known accumulations occur. The source rock is unknown; so long distance migration is postulated. Stratigraphic traps are predominant, but structural and combination traps exist. The Greenwood gas area (Figure 6a) is the largest gas accumulation in the play with estimated ultimate recovery of 1.8 trillion cubic feet of gas. Quinduno north field (outside the Study Area) is the largest oil accumulation in the play with an estimated ultimate recovery of 13 million barrels of oil (Henry and Hester, 1995). The potential of new discoveries was deemed insignificant in the 1995 USGS study. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

Permian Carbonate Stratigraphic Gas Play

The Permian Carbonate Stratigraphic Gas Play was the most significant hydrocarbon producer in the Anadarko Basin Province as of 1995. There are at least 30,000 well penetrations in the play. The Panhandle-Hugoton field has an estimated ultimate recovery of 83 trillion cubic feet of gas. The Permian Council Grove and Case Group arkosic washes, limestone, and dolomite make up the 500 to 2,000 foot reservoir. Porosity of the reservoir is from 12 to 16 percent with a median of 15 percent (Henry and Hester, 1995). Source rocks are from thermally mature shales. In the central part of the basin Pennsylvanian or older rocks may source the reservoirs. Long distance migration (up to several hundred miles) of hydrocarbons to the reservoir is likely. Oil in the Permian Carbonate Stratigraphic Gas Play is possibly from the Simpson Shale or Woodford Shale. Traps are primarily structural due to the Amarillo-Wichita Uplift. Hydrodynamics also plays a role in localizing hydrocarbons. In Kansas, the gas is trapped along the west by porosity loss where reservoir rocks grade into the tight red beds. Dolomite and anhydrite of the overlying Witchita Formation seal the reservoir. Discovery of new accumulations is not likely. West of the Panhandle-Hugoton field there is a lack of reservoir quality. This play has been extensively explored. See Tables A1-4 and A1-5 for undiscovered resources for this play within the Study Area.

DENVER BASIN PROVINCE ASSESSMENT

The Denver Basin Province is in Wyoming, Colorado, South Dakota, and Nebraska. It is within the Study Area (FIGURE A1-1). The west flank dips steeply while the east flank of the basin dips gently (Higley, Pollastro, and Clayton, 1995). The only play in the province is the Dakota Group (Combined J and D Sandstones) Play. The Denver Basin Province had produced 800 million barrels of oil and 1.2 trillion cubic feet of gas, as reported in the 1995 assessment. The largest oil field in the province boundary is Adena Field (north of the Study Area), with more than 60 million barrels of oil (as of 1995) and an estimated ultimate recovery (EUR) of 62.5 million barrels of oil (1995). Stratigraphic trapping (facies changes and pinch-outs) is predominant. Combination traps are also present.

The 2002 assessment of the Denver Basin Province, published by the U.S. Geological Survey in 2007, discussed productivity from the Lower Cretaceous Dakota Group, Upper Cretaceous Codell Sandstone Member of the Carlile Shale, Upper Cretaceous Niobrara Formation, Upper Cretaceous Laramie Formation, and Upper Cretaceous-Tertiary Denver Formation. Coalbed natural gas was not evaluated in this report due to low well control, little information, and no current production. Also, the Pierre Shale Assessment Unit, which was discussed in the 1995 report, was not assessed for continuous resources because of low potential from analysis of estimated ultimate recovery. Since the 1995 assessment report on the Denver Basin Province had more detail for each play area, the descriptions were combined with the 2002 assessment in the following summaries.

Play Summaries

One play area in the "1995 National Assessment of United States Oil and Gas Resources" for the Denver Basin Province is within the Study Area (Figure A1-9). The play area is the Dakota Group (Combined J and D Sandstones) Play. It is a conventional play area. Each play area is a set of discovered or undiscovered oil and gas accumulations or prospects that are geologically related. The U.S. Geological Survey defined a play "by the geological properties (such as trapping style, type of reservoir, nature of the seal) that are responsible for the accumulations or prospects." A conventional play contains oil and gas accumulations having hydrocarbon-water contacts and seals that hold or trap hydrocarbons. The hydrocarbons in these plays can be recovered using traditional development and production practices. The supporting geologic study for this play area is available at http://energy.cr.usgs.gov/oilgas/noga/1995.html (Higley et al., 1995).

Total Petroleum Systems and Assessment Unit Summaries

In their newest assessment (written in 2002 and published in 2007), the U.S. Geological Survey divided the Denver Basin Province into "Total Petroleum Systems" and "Assessment Units" (see Glossary definitions) rather than "Plays." A summary of the Total Petroleum System and Assessment Unit is provided below.

Lower Cretaceous Total Petroleum System

The Lower Cretaceous Total Petroleum System is in the northwestern portion of the Study Area (Figure A1-5). The assessment unit within the Study Area in the Lower Cretaceous Total Petroleum System is the Dakota Group and D Sandstone Assessment Unit. The 1995 assessment report provided detailed descriptions of this assessment unit. Therefore, the assessment unit and play descriptions are combined in each summary to provide a complete picture of the assessment unit/play.

Dakota Group (Combined J and D Sandstones) Play and Dakota Group and D Sandstone Assessment Unit

The Dakota Group (Combined J and D Sandstones) Play is in the northwestern portion of the Study Area (Figure A1-9). The stratigraphic extents of the play are from the base of the Lower Cretaceous Skull Creek Shale Member of the Lower Cretaceous Dakota Group to the top of the Upper Cretaceous "D" Sandstone. The Lower Cretaceous Muddy "J" Sandstone and Upper Cretaceous "D" Sandstones are reservoirs in this play. These two sandstones are usually commingled and have produced more than 700 million barrels of oil, 980 billion cubic feet of gas, and 68 million barrels of natural gas liquids as of the 2007 U.S. Geological Survey assessment (Higley et al., 2007). Distributaries, delta front environments, and valley-fill sandstones deposited the Lower Cretaceous Muddy "J" Sandstone and Upper Cretaceous "D" Sandstone during a regression of the Western Interior Seaway (Higley et al., 2007). Porosity ranges from 10 to 28 percent (Higley, Pollastro, and Clayton, 1995). Permeability averages 500 millidarcies but has been recorded at a maximum of 2,200 millidarcies (1995). The thickest stratigraphic portion of the Lower Cretaceous Dakota Group is 540 feet. Producing reservoirs average 25 feet thick and producing intervals are from 3,000 feet to more than 8,000 feet (Higley et al., 2007). The Lower Cretaceous Muddy "J" Sandstone outcrops along the western margin of the Denver Basin (2007). Source rocks reported in the 1995 report were the Lower Cretaceous Skull Creek Shale, Lower Cretaceous Muddy "J" Sandstone, Lower Cretaceous Mowry Shale, and Upper Cretaceous "D" Sandstone. The 2007 assessment stated the source rocks were from the Upper Cretaceous Mowry Shale and the Upper Cretaceous Graneros Shale for the Wellington field. The total organic carbon content is about 2.5 weight percent for the Upper Cretaceous Mowry Shale and Upper Cretaceous Graneros Shale in the Denver Basin (2007). The 2007 assessment states that stratigraphic traps are the primary trapping mechanism, while the 1995 report states combination traps as the predominant trapping mechanism. Overall, there are both stratigraphic and combination traps throughout the field. Some structural traps exist. While not in the Study Area, the Wellington Oil field, discovered in 1923, was the earliest discovery in this play (1995). More information on the Wellington Field is in the 2007 U.S. Geological Survey National Oil and Gas Assessment report. Potential to discover new accumulations in this play was fair as of the 1995 assessment. Undiscovered accumulations assessed for the 2007 report can be viewed in Tables A1-6 and A1-7.

LAS ANIMAS ARCH PROVINCE ASSESSMENT

All of the plays within the Province are outside the Study Area. They are all north of Baca County, Colorado. Although no plays from this Province are within the Study Area, the Las Animas Arch Province boundary is in Otero and Bent counties because the province connects the Denver Basin, Raton Basin-Sierra Grande, and Anadarko Basin Provinces together.

REFERENCES

Allis, R., T. Chidsey, W. Gwynn, C. Morgan, S. White, M. Adams, and J. Moore, 2001, Natural CO2 reservoirs on the Colorado Plateau and Southern Rocky Mountains: in First National Conference on Carbon Sequestration, 19 pages. Available online: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/6a2.pdf .

Anderman, G.G., 1961, Structure contour map of Colorado; in Burg R., and Rold J., eds., Lower and Middle Paleozoic Rocks of Colorado: Rocky Mountain Association of Geologists Guidebook, pages 101-105 and 2 sheets.

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.

Beserra, T., 2008, Oil classification and exploration opportunity in the Hugoton Embayment, western Kansas, and Las Animas arch, eastern Colorado; AAPG Search and Discovery Article #10146, 21 pages.

Bolyard, D.W., 1990, Upper Morrow "B" sandstone reservoir, Flank field, Baca County, Colorado: *in* S.A. Sonnenberg, L.T. Shannon, K. Rader, W.F. von Drehle, and G.W. Martin eds.; Morrow sandstones of southeast Colorado and adjacent areas: Rocky Mountain Association of Geologists Guidebook, p. 191-205.

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

Boyd, D., 2009, Milestones in the Oklahoma oil and gas industry, Oklahoma Geological Survey; Available Online: http://www.ogs.ou.edu/oilgasmilestones.php

Brainerd, A.E. and Van Tuyl, F.M., 1954, A resume of petroleum exploration and exploratory development in Colorado 1862-1954. Rocky Mountain Association of Geologists; The Oil and Gas Fields of Colorado—A Symposium, p. 15-24.

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

Bureau of Land Management, 2008, Analysis of natural gases 1917-October 2008; Bureau maintained database available on CD-ROM.

Bureau of Mines, 1957, Minerals yearbook area reports 1957, volume III, p. 255.

Bureau of Mines, 1968, Minerals yearbook area reports: domestic 1964, volume III, p. 252.

Clair, J.R., and B.B. Bradish, 1956, Model Dome gas field Las Animas County, Colorado; Guidebook to the Geology of the Raton Basin, Colorado, Rocky Mountain Association of Geologists, p. 80 and 81.

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. Available online: http://www.bu.edu/cees/research/workingp/0302.html.

Colorado Geological Survey, 2011, digital data provided to the Bureau of Land Management.

Colorado Oil and Gas Conservation Commission, 2011, Colorado well data and statistics: Colorado Oil and Gas Conservation Commission Online database. Available online: http://cogcc.state.co.us.

Davis, H.G., 1964, Kinsler Morrow gas field Morton County, Kansas; Oklahoma City Geological Society, The Shale Shaker Digest IV, Volumes XII-XIV (1961-1964) p. 406-424.

Deutsche Bank, 2011. Commodities Outlook. Deutsche Bank AG/London, Global Markets Research, David Folkerts-Landau, Global Head of Research. Downloaded September 13, 2011 from http://dbstars-asia.db.com/data/20110118084400J/data/report12-5.pdf?dbiquery=null%3Apetroleum+outlook.

Dobbin, C.E., 1935, Geology of natural gases rich in gelium, nitrogen, carbon dioxide, and hydrogen sulphide: AAPG Special Publication 7 – Geology of Natural Gas, p. 1053-1072.

Dubois, M.K., A.P. Byrnes, G.C. Bohling, J.H. Doveton, 2006, Multiscale geologic and petrophysical modeling of the giant Hugoton gas field (Permian), Kansas and Oklahoma, U.S.A.; *in* P.M. Harris and L.J. Weber, eds., Giant hydrocarbon reservoirs of the world: From Rocks to reservoir characterization and modeling. AAPG Memoir 88/SEPM Special Publication, p. 307-353.

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

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

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

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

Energy Information Administration, 2006a, 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, 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 2007b, 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://tonto.eia.doe.gov/FTPROOT/financial/020606.pdf .

Energy Information Administration 2009a, Performance profiles of major energy producers 2008: U.S. Department of Energy, Office of Energy Markets and End Use, published December, 2009; DOE/EIA-0206(08), 108 pages. Available online: http://tonto.eia.doe.gov/FTPROOT/financial/020608.pdf .

Energy Information Administration, 2009c, Annual Energy Outlook 2009 with Projections to 2030, Updated Annual Energy Outlook 2009 Reference Case with ARRA, DOE/EIA-0383(2009), 230 pages. Available online: http://www.eia.doe.gov/oiaf/aeo/index.html .

Energy Information Administration, 2011a, Petroleum product spot prices, downloaded March 11, 2011 from http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SCO_a.htm and http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=F004008__3&f=M.

Energy Information Administration, 2011b, Annual Energy Outlook 2011 with projections to 2035; Updated Annual Energy Outlook 2011 Reference Case, DOE/EIA-0383(2011), downloaded April 27, 2011 from http://www.eia.gov/forecasts/aeo/.

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

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.

Hemborg, H.T., 1993, Southeast Colorado plays; *in* Atlas of Major Rocky Mountain Gas Reservoirs; Rocky Mountain Bureau of Mines and Mineral Resources, p. 115--117.

Henry, M.E., and Hester, T.C., 1995, Anadarko Basin Province (058), United States Geological Survey 1995 National Oil and Gas Assessment Geologic Report, downloaded February 9, 2011 from the United States Geological Survey website: http://certmapper.cr.usgs.gov/data/noga95/prov58/text/prov58.pdf.

Higley, D.K., compiler, 2007, Petroleum systems and assessment of undiscovered oil and gas in the Raton Basin–Sierra Grande Uplift Province, Colorado and New Mexico—USGS Province 41: U.S. Geological Survey Digital Data Series DDS–69–N, 141p. Available online: http://pubs.usgs.gov/dds/dds-069/dds-069-n/.

Higley, D.K., Cook, T.A., Pollastro, R.M., Charpentier, R.R., Klett, T.R., and Schenk, C.J., 2007, Executive Summary—2005 Assessment of Undiscovered Oil and Gas Resources in the Raton Basin–Sierra Grande Uplift Province of Colorado and New Mexico, *in* Higley, D.K., compiler, Petroleum systems and assessment of undiscovered oil and gas in the Raton Basin–Sierra Grande Uplift Province, Colorado and New Mexico—USGS Province 41 : U.S. Geological Survey Digital Data Series DDS–69–N, ch. 1, 2 p.; Available online: http://pubs.usgs.gov/dds/dds-069/dds-069-n/

Higley, D.K., Charpentier, R.R., Cook, T.A., Klett, T.R., Pollastro, and R.M., Schmoker, 2007, Assessment of Undiscovered Oil and Gas in the Denver Basin Province, Colorado, Kansas, Nebraska, South Dakota, and Wyoming: U.S. Geological Survey National Assessment of Oil and Gas; Available online: http://pubs.usgs.gov/dds/dds-069/dds-069-p/.

Higley, D.K., Cook, T.A., Pollastro, R.M., Charpentier, R.R., Klett, T.R., and Schenk, C.J., 2007, Executive Summary—2005 Assessment of Undiscovered Oil and Gas Resources in the Raton Basin–Sierra Grande Uplift Province of Colorado and New Mexico, *in* Higley, D.K., compiler, Petroleum systems and assessment of undiscovered oil and gas in the Raton Basin–Sierra Grande Uplift Province, Colorado and New Mexico—USGS Province 41 : U.S. Geological Survey Digital Data Series DDS–69–N, ch. 1, 2 p.; Available online: http://pubs.usgs.gov/dds/dds-069/dds-069-n/.

Higley, D.K., Pollastro, R.M., Clayton, J.L., 1995, Denver Basin Province (039): U.S. Geological Survey National Oil and Gas Assessment; Available online: http://certmapper.cr.usgs.gov/noga/broker1995.jsp?theProvince=39&thePage=basin&theServlet=NogaMainResultsServ.

IHS Energy Group, 2011, 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, 2011, Hydraulic Fracturing: available online; http://groundwork.iogcc.org/topics-index/hydraulic-fracturing .

Kansas Corporation Commission, 2011, Hydraulic Fracturing – Frequently Asked Questions: Available online; http://www.kcc.state.ks.us/conservation/faq_hydraulic_fracturing.htm.

Kansas Geological Survey, 2011a, Master list of oil and gas wells in Kansas. Available at: http://www.kgs.ku.edu/Magellan/Qualified/index.html .

Kansas Geological Surbey, 2011b, Micro scale nitrogen rejection plant information site: information available from: http://www.kgs.ku.edu/PRS/Microscale/reports.html.

Keighin, C.W., 1995, Raton Basin-Sierra Grande Uplift Province (041): U.S. Geological Survey National Oil and Gas Assessment; Available online: http://certmapper.cr.usgs.gov/noga/broker1995.jsp?theProvince=41&thePage=basin&theServlet=NogaMainResultsServ.

Kim, E, 2007, North America gas production trends & issues: presentation for Wood Mackenzie Research and Consulting at Gas/Electric Partnership Workshop on February 8, 2007; 34 pages. Available online: http://www.gaselectricpartnership.com/AAWOODMAC.pdf .

Knopman, D., 2002, Assessing Gas and Oil Resources in the Intermountain West: RAND CT-195, p. 1-13. Available online: http://www.rand.org/pubs/testimonies/CT195/.

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, 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/.

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

Matson, R.M., and R.C. Schneider, 1968, Oil and gas exploration in southeastern Colorado; The Mountain Geologist, volume 5, p. 89-94.

Merriam, D.F., 1963, The geologic history of Kansas": Kansas Geological survey Bulletin 162; available online at: http://www.kgs.ku.edu/Publications/Bulletins/162/index.html.

Moline, B., chairman, 2006, Southwest Kansas H_2S and low pressure task force: prepared by a working group for the Kansas Corporation Commission, 76 pages. Available online: http://www.kcc.state.ks.us/pipeline/task_force_report.pdf.

Nation, L., 2002, Resource Paper Taken to Task: Congressional Panel Hears Mankin. In: *Explorer* by AAPG. Available online: http://www.aapg.org/explorer/2002/06jun/testimony.cfm.

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.

Newell, K.D., 2007, Geochemical trends in gas quality in Kansas: Kansas Geological Survey Open File Report 2007-8, available on line: http://www.kgs.ku.edu/PRS/publication/2007/2007-8/index.html

Nzlegacy (New Mexico and Arizona Land Company, LLC.), (2004) The Anadarko Basin. Accessed December 2, 2010 through: http://www.nzlegacy.com/NZ%20Oil%20and%20Gas%20LLC.htm .

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

Petak, K.R., 2010. Fundamentals Point to Growth, Stronger Prices in the Long Term. The American Oil & Gas Reporter, October, 2010. Downloaded September 13, 2011 from http://www.aogr.com/index.php/magazine/cover_story_archives/october_2010_cover_story/.

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.

Pustmueller, P.S., 1958, Pennsylvanian oil and gas in southeastern Colorado; *in* B. Curtis ed., Symposium on Pennsylvanian Rocks of Colorado and Adjacent Areas 1958, p. 129-134.

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.

Rocky Mountain Association of Geologists, 1972, Geologic atlas of the Rocky Mountain region: W. Mallory ed., Denver, Colorado, 331 pages.

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.O.I Bureau of Land Management, U.S. Environmental Protection Agency, U.S.D.O.I. Fish and Wildlife Service, U.S.D.O.I. National Park Service, and U.S.D.A Forest Service: Final Report published January 16, 2004; 100 pages.

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

Shoenfelt, C.E., 1938, Oil and gas development in eastern Colorado, Along the Front Range of the Rocky Mountains, Colorado: Guidebook, 12th Annual Field Conference. Kansas Geological Society, 2006, p. 91-102.

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.

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

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

Sonnenberg, S.S., and W.F. von Drehle, 1990, Morrow gas composition in southeast Colorado: *in* S.A. Sonnenberg, L.T. Shannon, K. Rader, W.F. von Drehle, and G.W. Martin eds.; Morrow sandstones of southeast Colorado and adjacent areas: Rocky Mountain Association of Geologists Guidebook, p. 233-235.

Sonnenberg, S.A., L.T. Shannon, K. Rader, W.F. von Drehle, and G.W. Martin eds., 1990, Morrow sandstones of southeast Colorado and adjacent areas: Rocky Mountain Association of Geologists Guidebook, 241 pages.

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

Tremain, C.M., 1993, Low-btu gas in Colorado; *in* Atlas of Major Rocky Mountain Gas Reservoirs; Rocky Mountain Bureau of Mines and Mineral Resources, p. 172.

Tweto, O., 1979, Geologic map of Colorado: U.S. Geologic Survey, map.

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/carbon_seq/refshelf/atlas/index.html.

U.S. Department of Energy, 2008, 2009 carbon sequestration atlas of the United States and Canada, second edition: 89 pages. Available online: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/index.html .

U.S. Department of Energy, 2010, 2010 carbon sequestration atlas of the United States and Canada, third edition: 161 pages. Available online: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/index.html .

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 III Inventory—Onshore United States. p. 1-392. Available online: http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/EPCA_III.html.

U.S. Geological Survey, 2011, Map Data—ArcMap

U.S. Geological Survey, 2010, Assessment of Undiscovered Oil and Gas Resources of the Anadarko Basin Province of Oklahoma, Kansas, Texas, and Colorado, 2010. Downloaded May 23, 2011 from http://pubs.usgs.gov/fs/2011/3003/pdf/FS11-3003.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/.

Watney, W.L., 1984, Favorable reservoir trends in the Pennsylvanian Lansing-Kansas City cyclic carbonates in western Kansas; Tulsa Geological Society Special Publication No. 2, p. 201-246.

Young, G.B.C., V.A. Lintz, B.L. Widmann, D.A. Bird, and J.A. Cappa, 2007, CO_2 sequestration potential of Colorado: Colorado Geological Survey, Resource Series 45, 212 pages.

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.

Analysis period. January 1, 2011 through December 31, 2030.

Associated water. Water that is produced from a well in association with production of conventional oil and gas, carbon dioxide gas, or 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).

British Thermal Unit (btu). 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.

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."

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.

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.

Held by production. This usually refers specifically to oil and gas leased that are productive and are held beyond their primary term because they are producing oil or gas in economic quantities.

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.

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.

Nonconventional hydrocarbons (Unconventional hydrocarbons). Nonconventional hydrocarbons are generally thought of as hydrocarbons that are created in formations without the permeability necessary to allow significant migration. They are generally described as those hydrocarbon 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 gas, shale oil, or deep gas.

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.

Rotary drilling rig. A modern drilling unit capable of drilling a well with a bit attached to a rotating column of steel pipe.

Spacing pattern. The pattern of well locations, which could be one well location per 40, 80, 160, 320, or 640 acres for the Study Area.

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

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

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

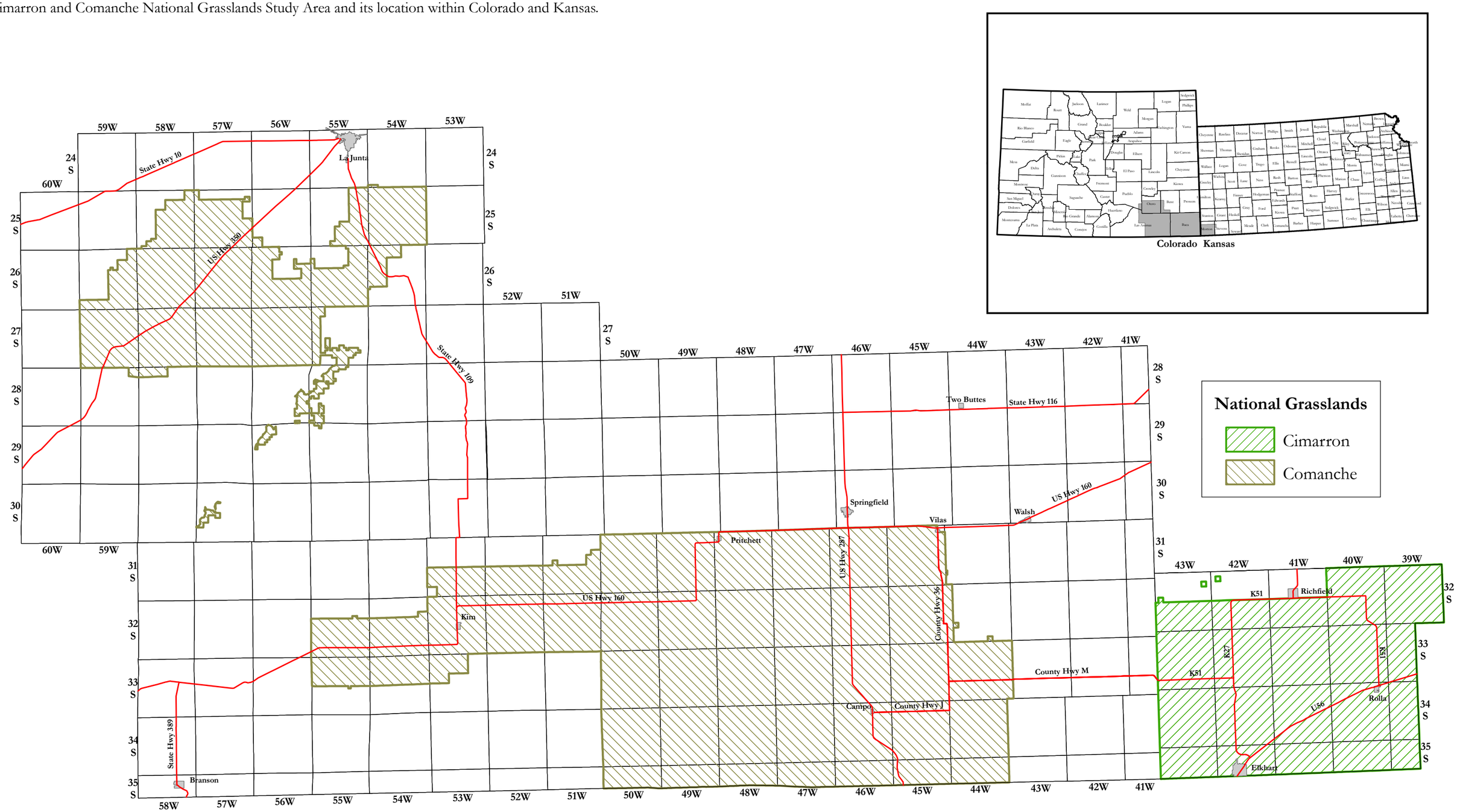
Technically recoverable resources. The volume of hydrocarbons which are recoverable using current exploration and production technology without regard to cost, which is a proportion of the estimated in-place resource.

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.

Figure 1.
Cimarron and Comanche National Grasslands Study Area and its location within Colorado and Kansas.



May, 2011

Dean P. Stilwell, Geologist
Al Elser, Geologist
Amber Robbins, Geologist

0 5 10 20 30 40 Miles

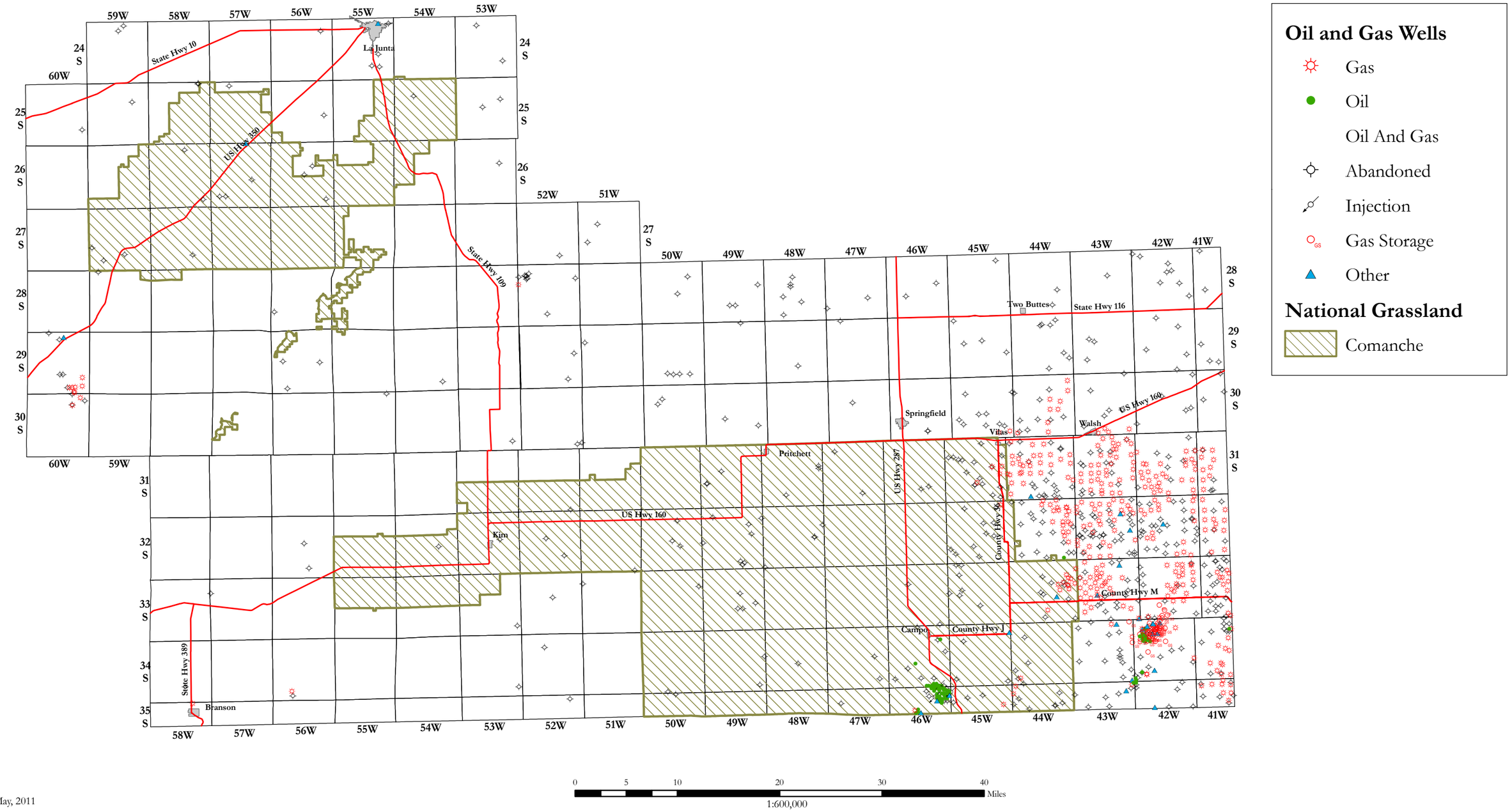
1:600,000

N

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 2a.

Location and initial status of all oil and gas wells drilled within the Comanche National Grassland Study Area. Data from IHS Energy Group (2011) and Colorado Oil and Gas Conservation Commission (2011).

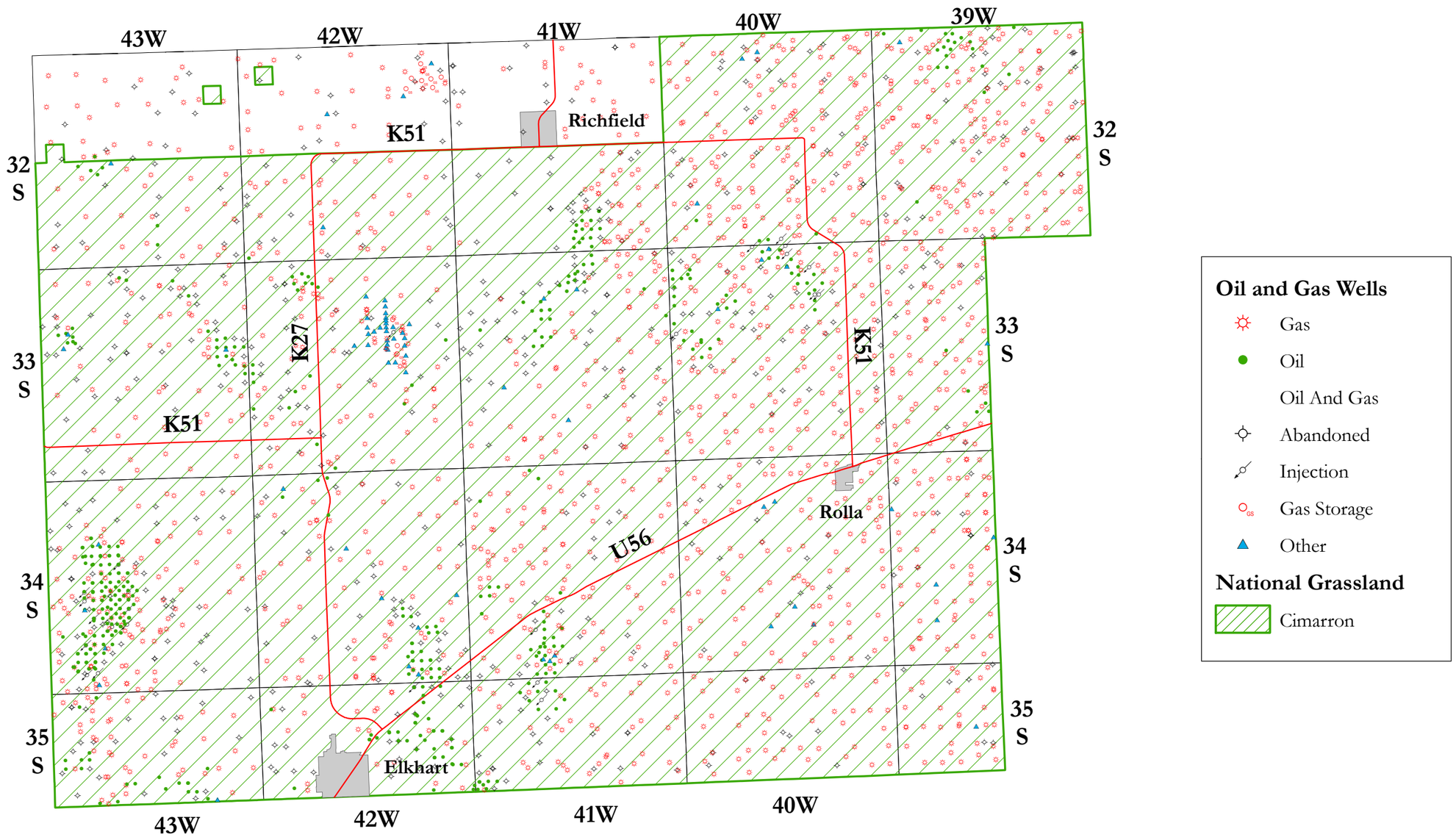


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 2b.
Location and initial status of all oil and gas wells drilled within the Cimarron National Grassland Study Area. Data from IHS Energy Group (2011) and Kansas Geological Survey (2011).



May, 2011

Dean P. Stilwell, Geologist
Al Elser, Geologist
Amber Robbins, Geologist

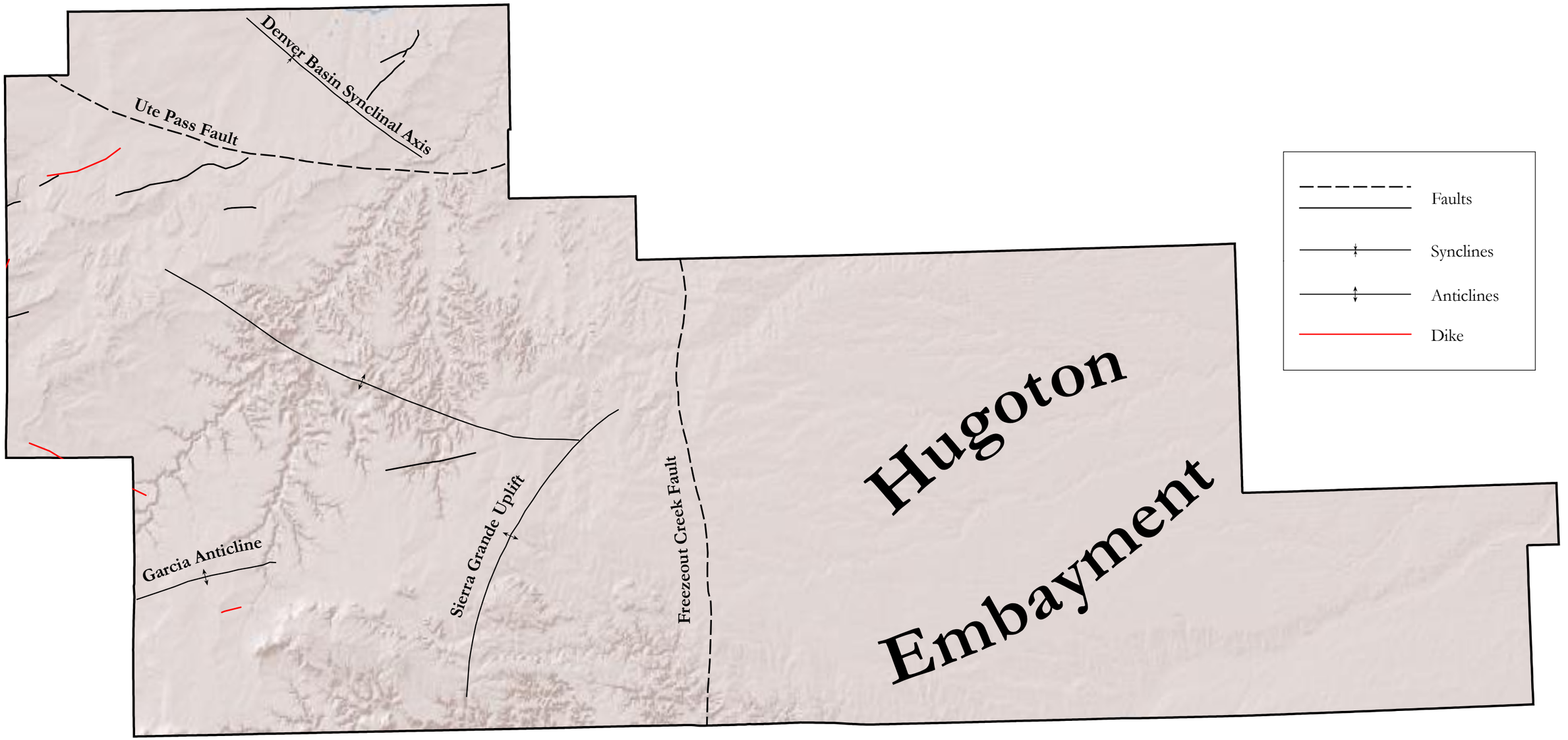
0 1.5 3 6 9 12 Miles

1:200,000

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 3.
Shaded relief map with major structural elements and selected geologic units of the Cimarron and Comanche National Grasslands Study Area. After Tweto (1979) and Anderman (1961).



0 5 10 20 30 40 Miles
1:600,000

May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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

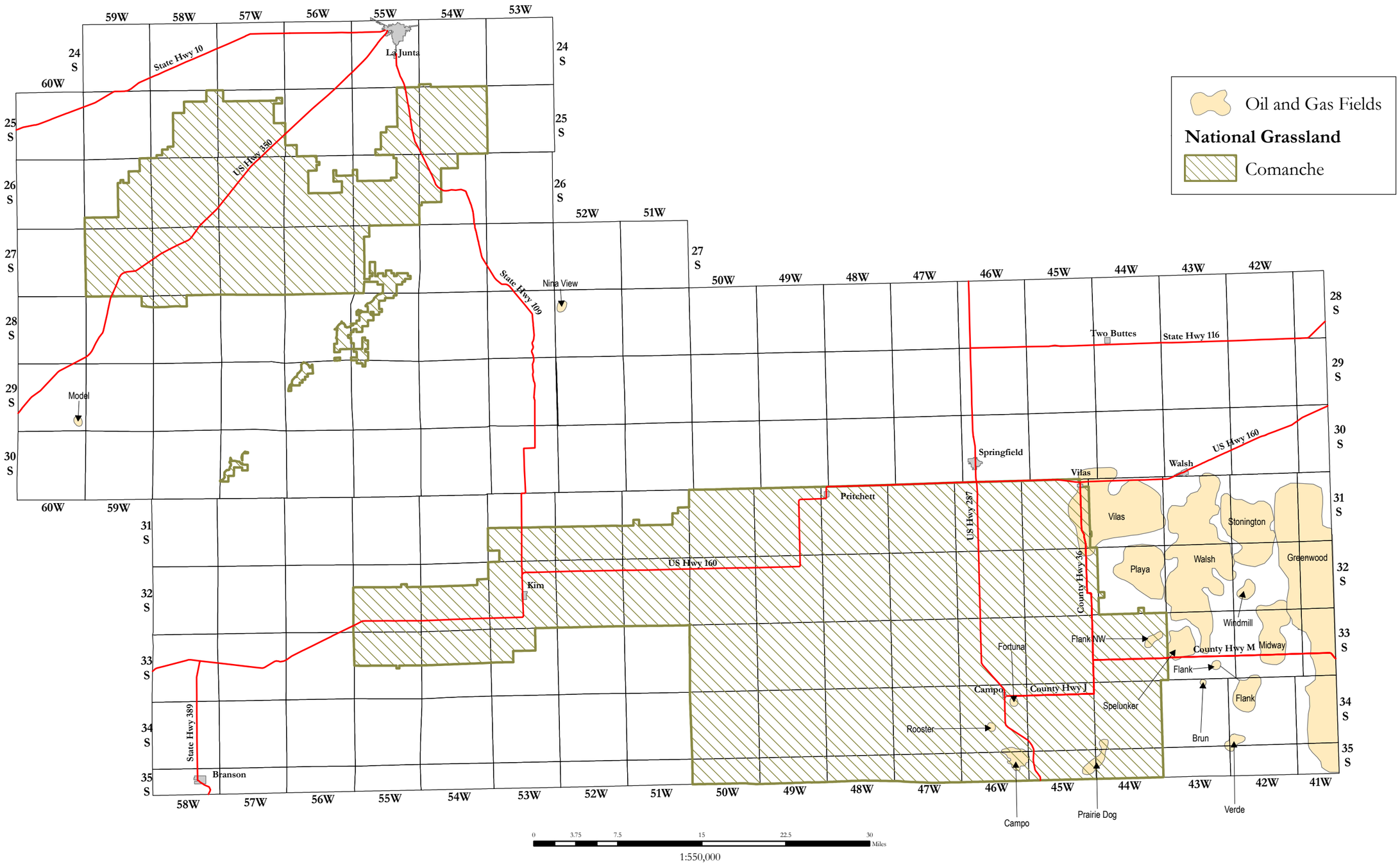
Figure 4. Stratigraphic chart of the Hugoton Embayment and Las Animas Arch within the Cimarron and Comanche National Grasslands Study Area (after Henry and Hester, 1995; and Keighin, 1995).

Era	Period	Epoch	***Hugoton Embayment***		***Las Animas Arch***
			Rock Unit		
Cenozoic	Quaternary	Pleistocene	Ogallala Formation		
		Pliocene			
	Neogene	Miocene			
	Paleogene	Oligocene	*hiatus*		
		Eocene			
		Paleocene			
Mesozoic	Cretaceous	Upper			
		Lower	Dakota Sandstone		
	Jurassic	Upper	*hiatus*		
		Lower	*Jurassic siltstones and sandstones*		*hiatus*
	Triassic	Upper	*hiatus*		
		Lower			
Paleozoic	Permian	Upper			Taloga Formation
		Middle	Big Basin Formation		
			Dog Creek Dolomite		Day Creek Dolomite
			Whitehorse Formation		
			Nippewalla Group		
		Lower	Sumner Group	Stone Corral Formation	Sumner Group
				Ninnescah Fm. (inc. Red Cave/Runnymede s.s.)	
				Wellington Formation	
			Chase Group		
			Council Grove Group (including Neva Formation)		
	Pennsylvanian	Upper	Admire Group		
			Wabaunsee Group		
			Shawnee Group (including Topeka, Lecompton and Oread limestones)		
			Douglas Group		
			Lansing Group		
			Kansas City Group		
			Pleasanton Group		Marmaton Group
		Middle	Marmaton Group		
			Cherokee Group		
		Lower	Atoka Group		Morrow Group
			Morrow Group	Kearny Formation	
				Keyes Sand	
	Mississippian	Upper	Ste. Genevieve Formation		
			St. Louis Formation		
			Salem Formation		
			Warsaw Formation		
			Osage Chert (informal)		Harrison Shale and St. Joseph Formation
		Lower	Gilmore City Limestone		Gilmore City Limestone and Misener sand
			Hannibal Shale		*hiatus*
	Devonian		Chattanooga Shale		
	Silurian		Hunton Group	Chimneyhill Dolomite	
	Ordovician		Maquoketa Shale		
			Viola Formation		
			Simpson Group		
	Cambrian		Arbuckle Group		
			Reagan Sandstone		

Figure 5. Stratigraphic chart of the Raton Basin within the Cimarron and Comanche National Grasslands Study Area (after Highley, 2007)

Era	Period	Epoch	Rock Unit	
Cenozoic	Quaternary	Pleistocene	Ogallala Formation	
		Pliocene		
	Neogene	Miocene	Devil's Hole Formation	
	Paleogene	Oligocene	Farasita Formation	
		Eocene	Huerfano Formation	
			Cuchara Formation	
		Paleocene	Poison Canyon Formation	
			Raton Formation	
Mesozoic	Cretaceous	Upper	Vermejo Formation	
			Trinidad Sandstone	
			Pierre Shale	
			Niobrara Formation	Smoky Hill Marl
				Fort Hays Limestone
			Benton Shale	Codell Sandstone
				Carlile Shale
				Greenhorn Limestone
				Graneros Shale
		Lower	Dakota Sandstone	
	Jurassic	Upper	*hiatus*	
			Morrison Formation	
			Entrada Sandstone	
	Triassic	Upper	Dockum Group	
		Lower	*hiatus*	
Paleozoic	Permian	Upper		
		Middle	Bernal Formation	
			San Andres Limestone	
		Lower	Glorieta Sandstone	
			Yeso Formation	
			Sangre de Cristo Formation	
	Pennsylvanian	Upper		
		Middle	Magdalena Group	
		Lower	*hiatus*	
	Mississippian	Upper	Tererro Formation	
		Lower	*hiatus*	
	Devonian		Espirtu Santo Formation	

Figure 6a.
Oil and gas fields within the Comanche National Grassland portion of the Study Area (Colorado Geological Survey, 2011).

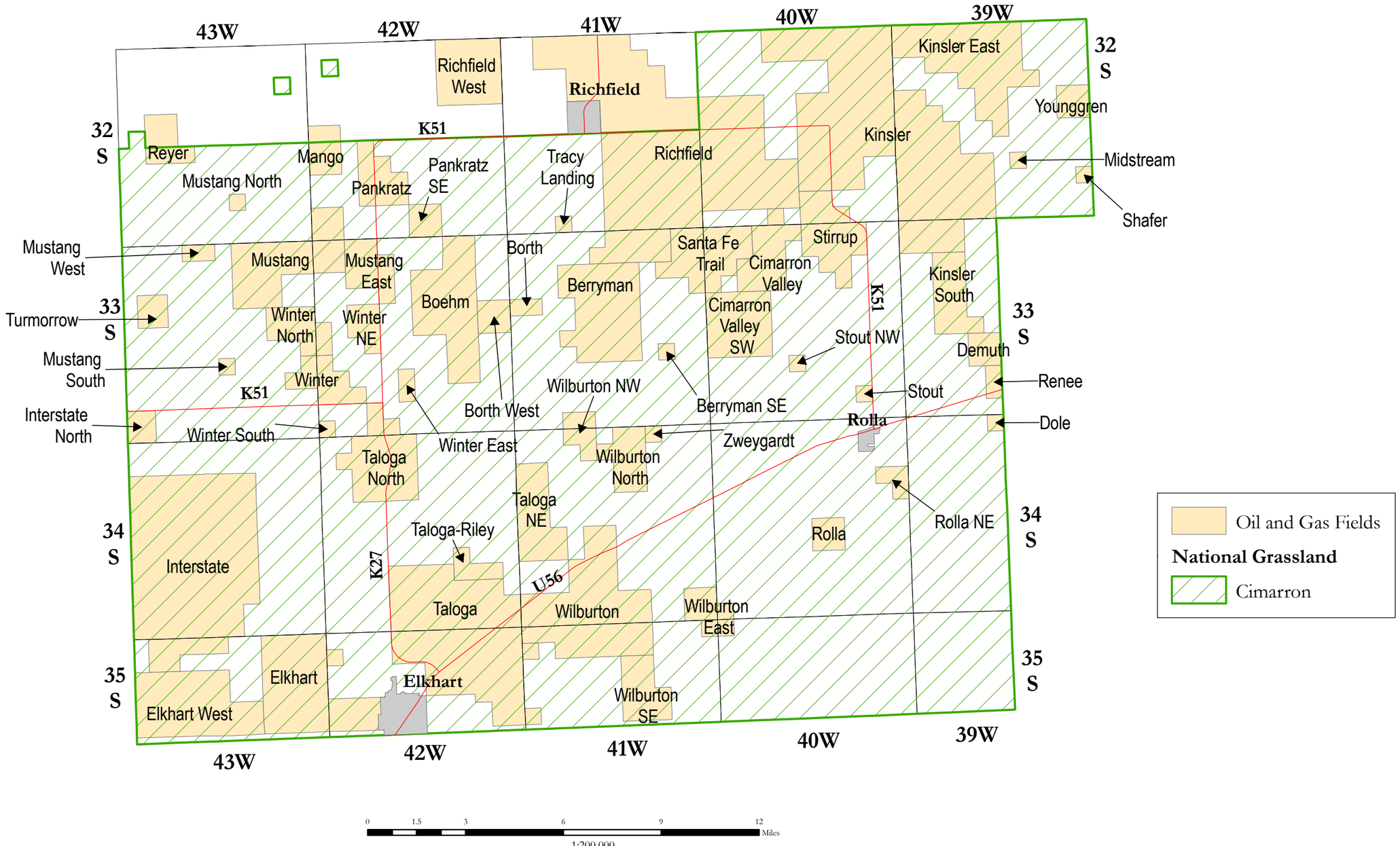


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 6b.
Oil and gas fields within the Cimarron National Grassland portion of the Study Area (Kansas Geological Survey, 2011).

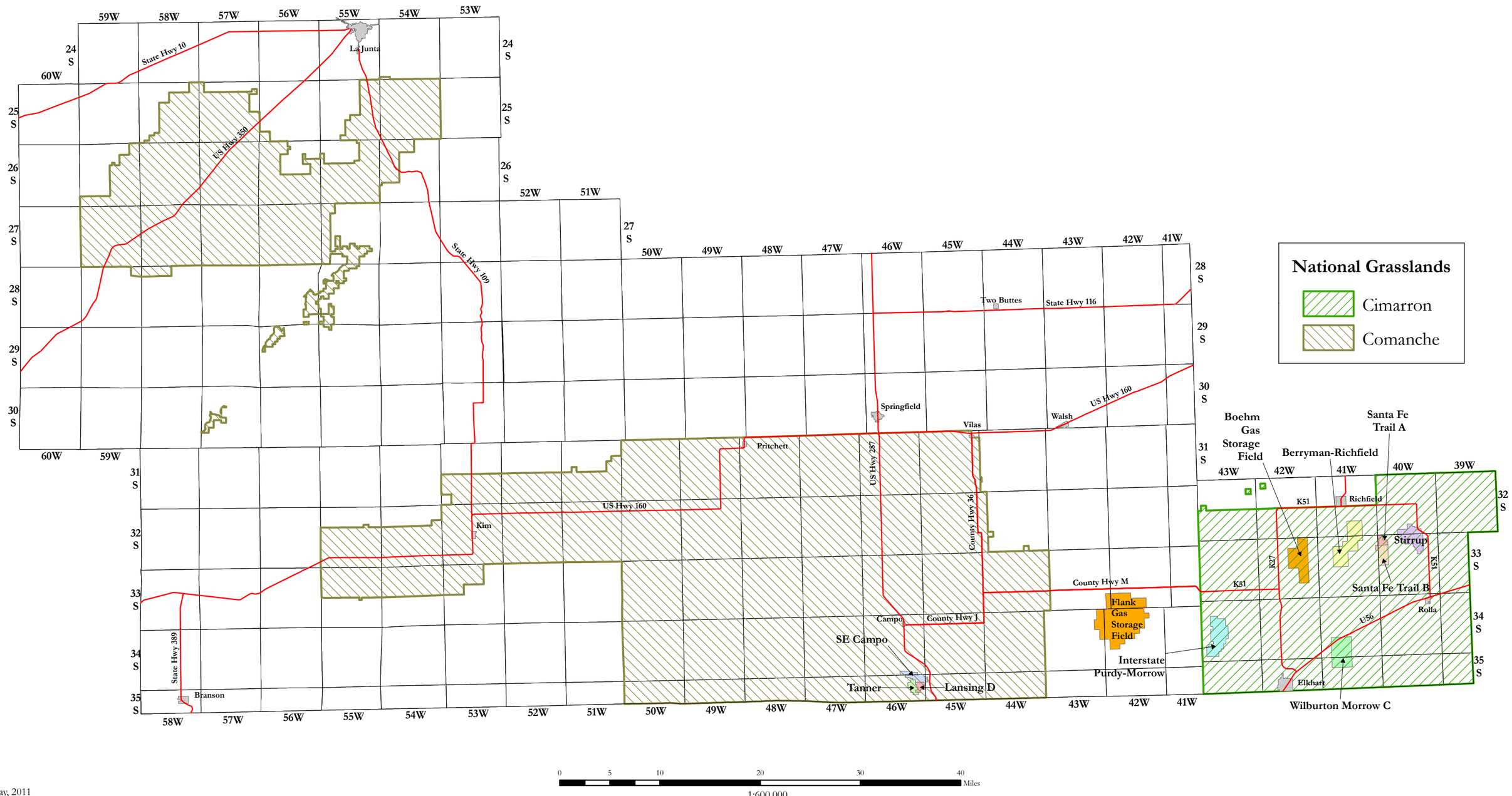


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 7.
Location of Federal oil and gas unit agreements and gas storage fields within the Cimarron and Comanche National Grasslands Study Area. Data from Bureau of Land Management files and Premier Data Services.

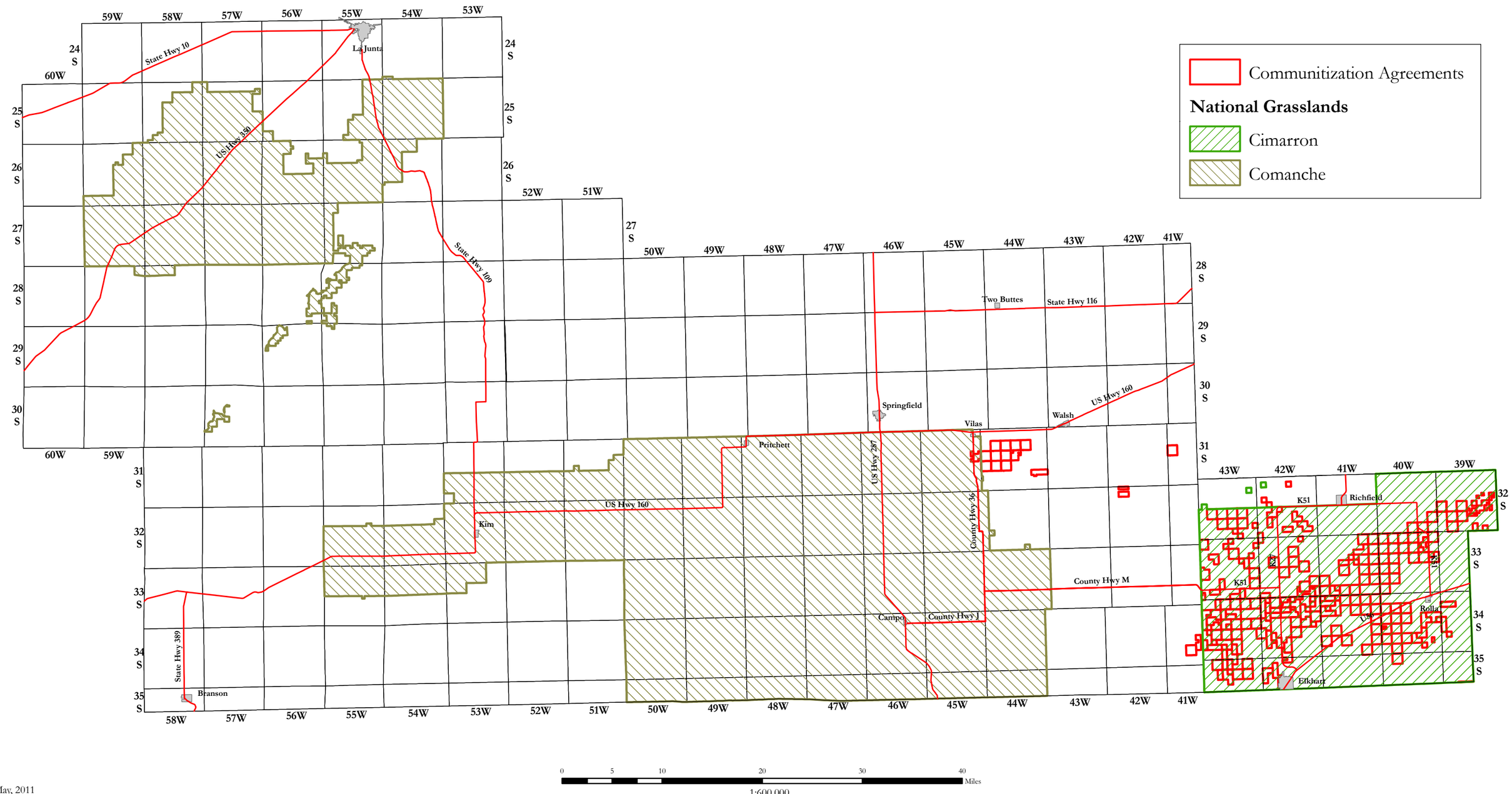


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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. This map is produced in cooperation with Premier Data Services, Arvada Colorado.

Figure 8.
Location of Federal communitization agreements within the Cimarron and Comanche National Grasslands Study Area. Data from Bureau of Land Management files and Premier Data Services.



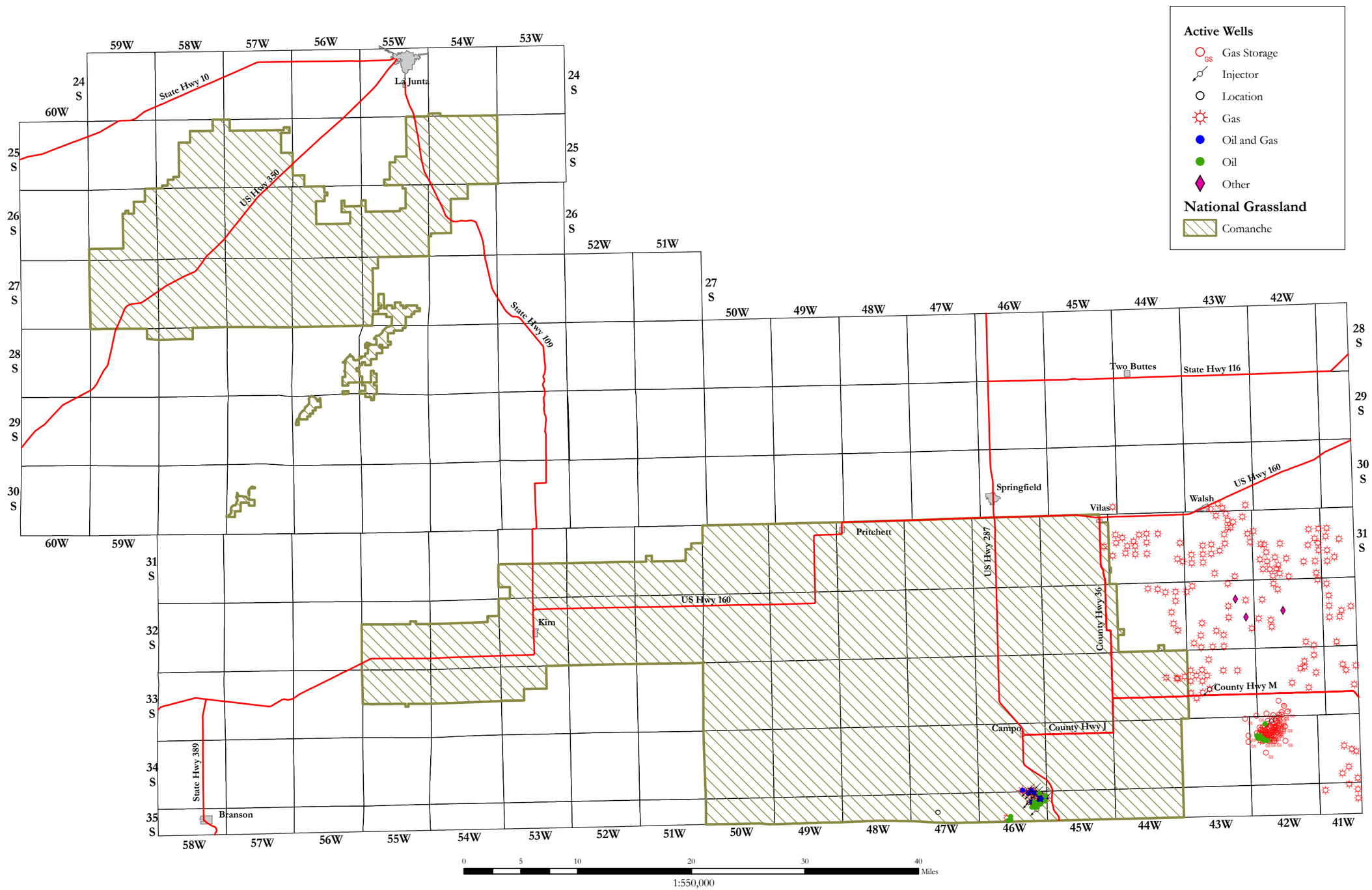
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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. This map is produced in cooperation with Premier Data Services, Arvada Colorado.

Figure 9a.

Comanche National Grassland Study Area locations of all oil and gas wells still in an active status. Data from IHS Energy Group (2011) and Colorado Oil and Gas Conservation Commission (2011).



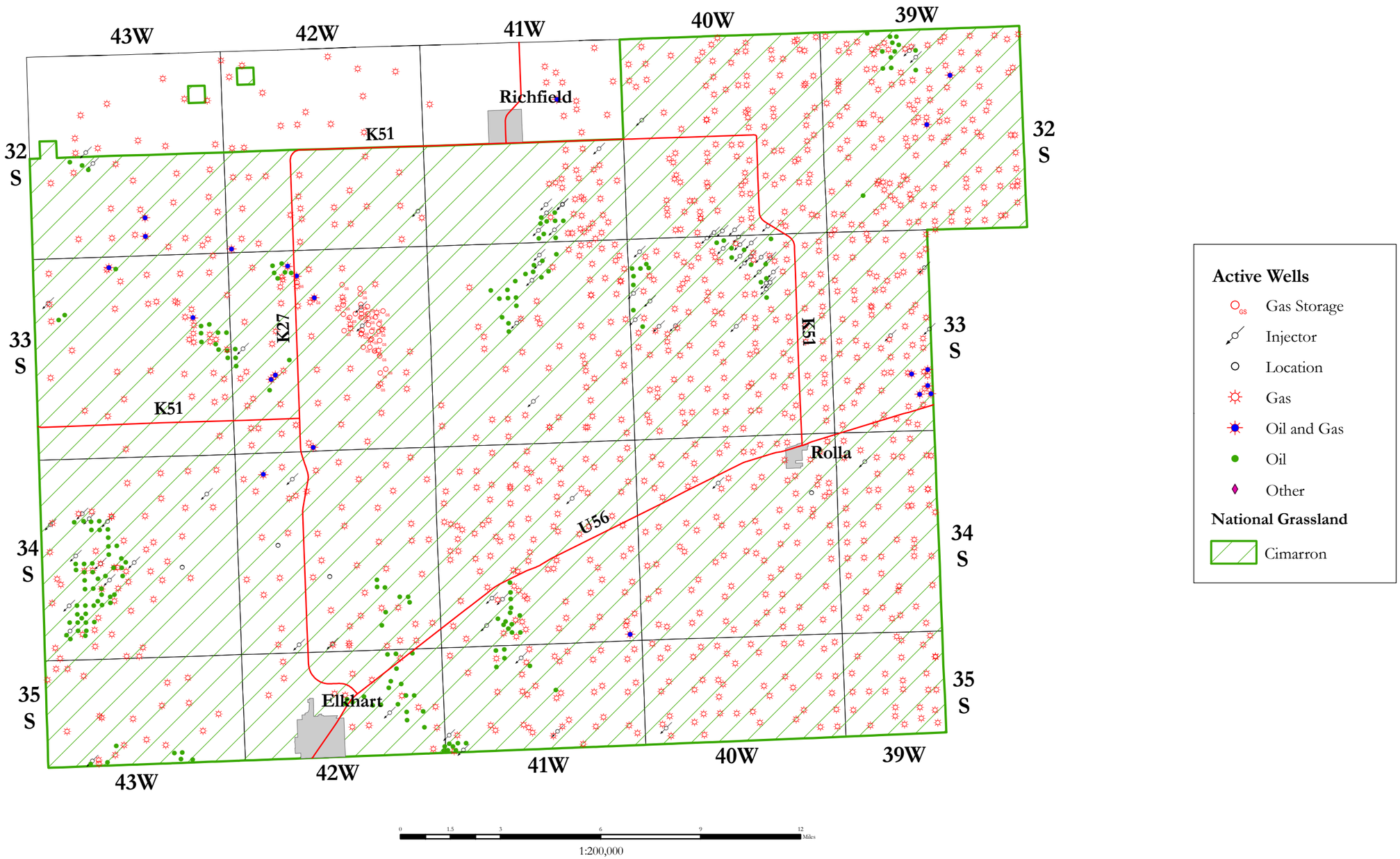
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 9b.

Cimarron National Grassland Study Area locations of all oil and gas wells still in an active status and well locations with an active application to drill. Data from IHS Energy Group (2011) and Kansas Geological Survey (2011).



May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 10. Wells spudded in the Colorado part of the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).

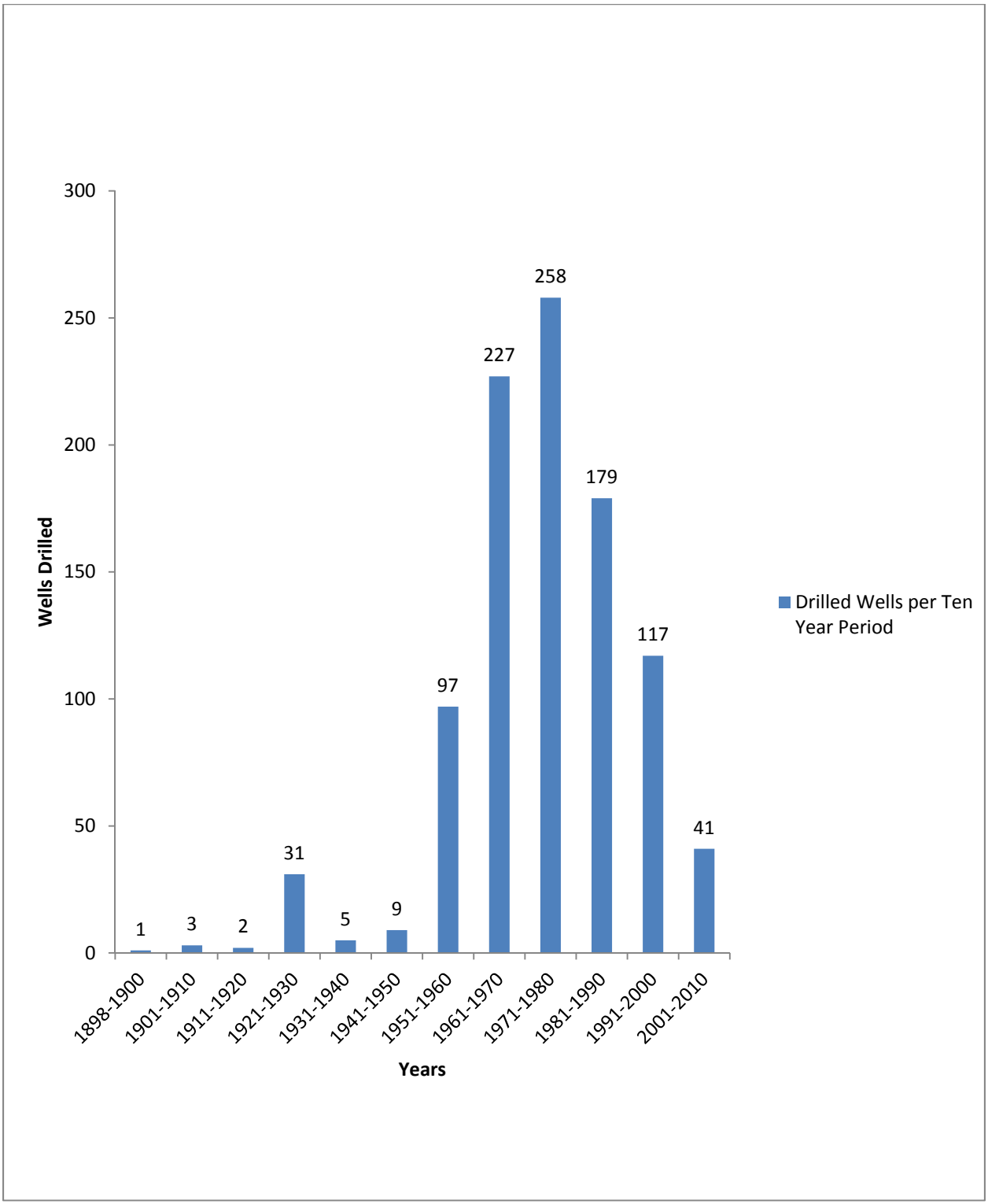


Figure 11. Wells spudded in the Kansas part of the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).

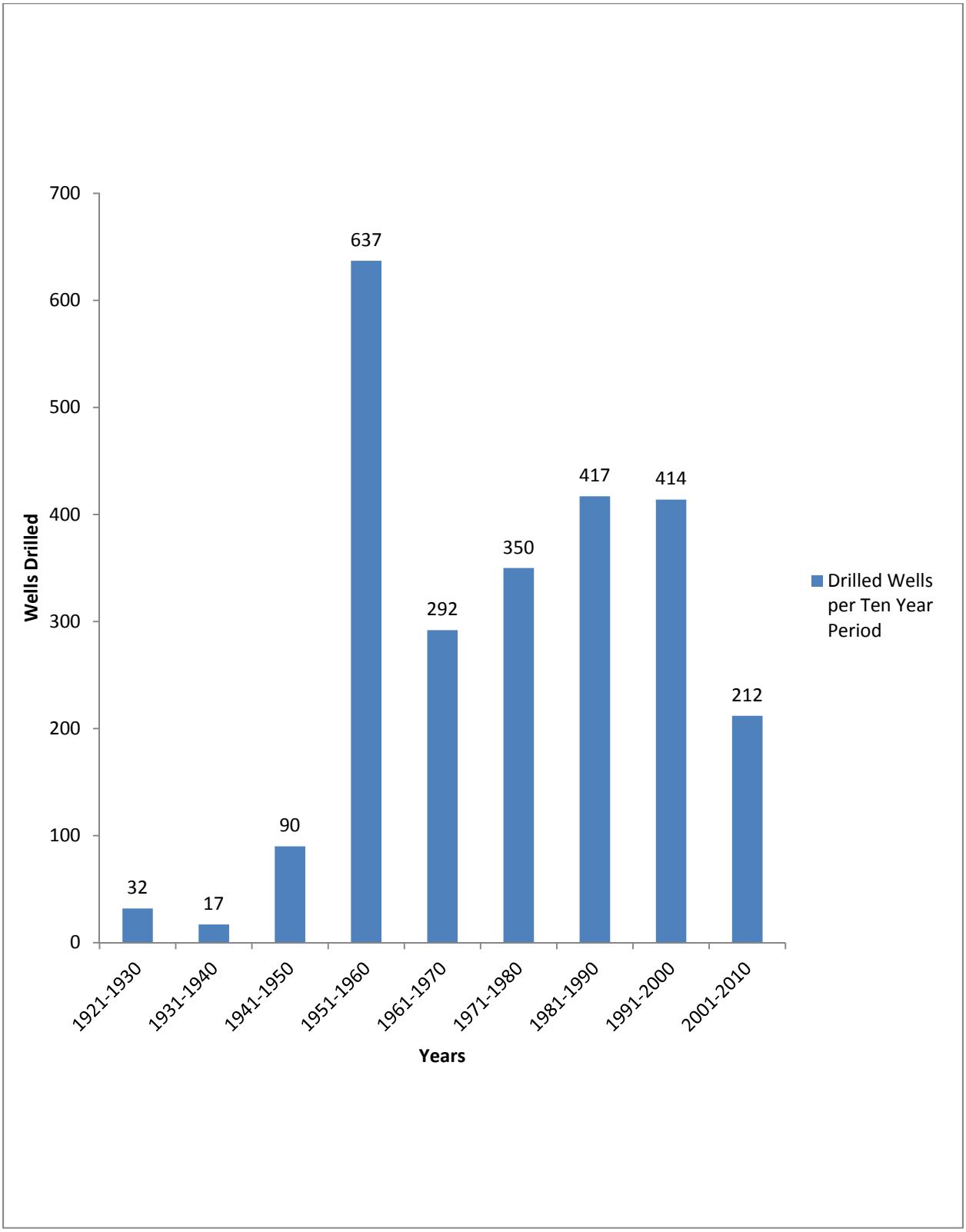


Figure 12. All wells spudded in the Cimarron and Comanche National Grasslands Study Area by 10 year period (IHS Energy Group, 2011).

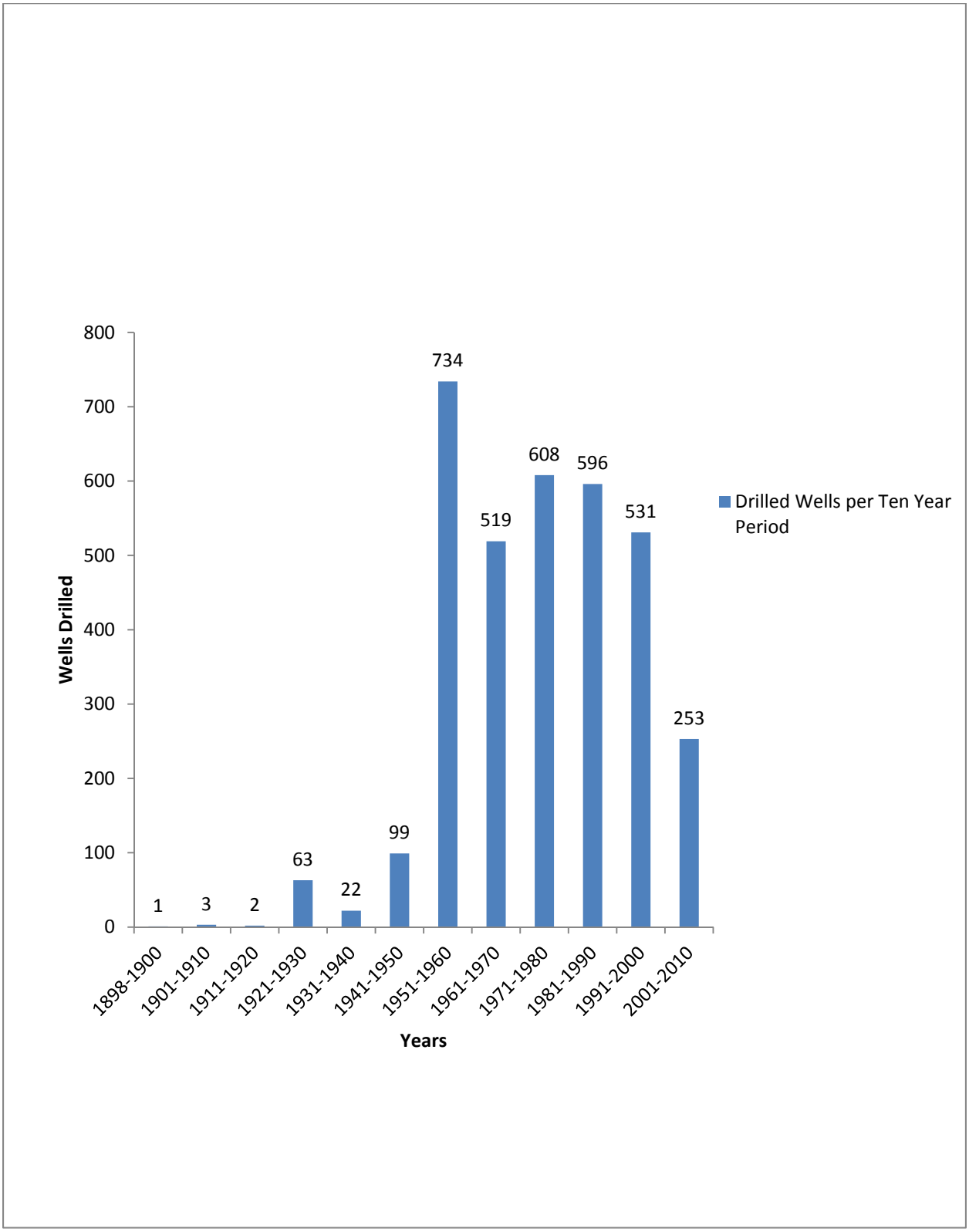
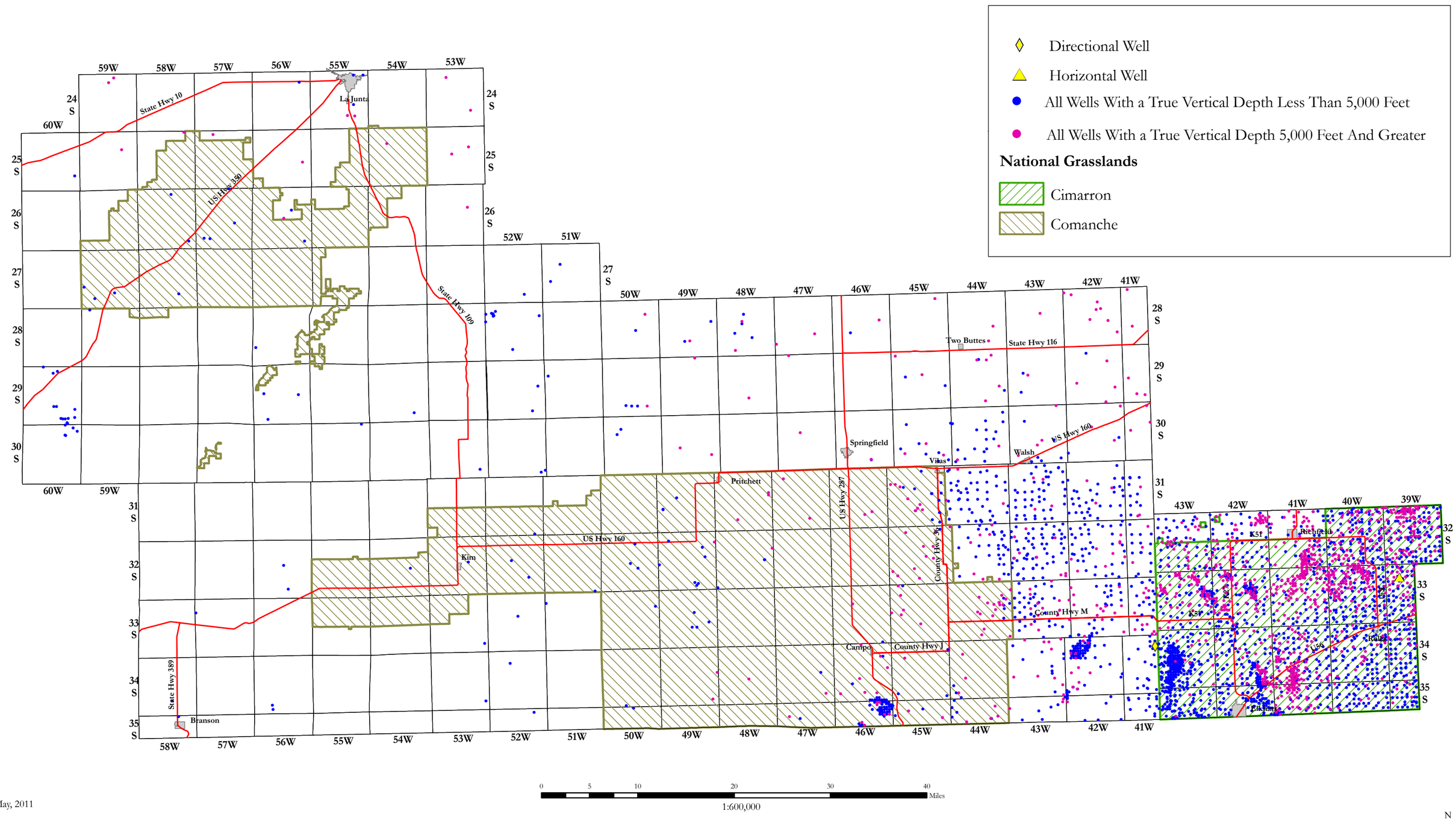


Figure 13.

True vertical depths of vertical, directional and horizontal wells within the Cimarron and Comanche National Grasslands Study Area. Data from IHS Energy Group (2011), Colorado Oil and Gas Conservation Commission (2011) and Kansas Geological Survey (2011).



May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 14. Annual and cumulative oil production from wells in the Cimarron and Comanche National Grasslands Study Area. Data from IHS Energy Group (2011).

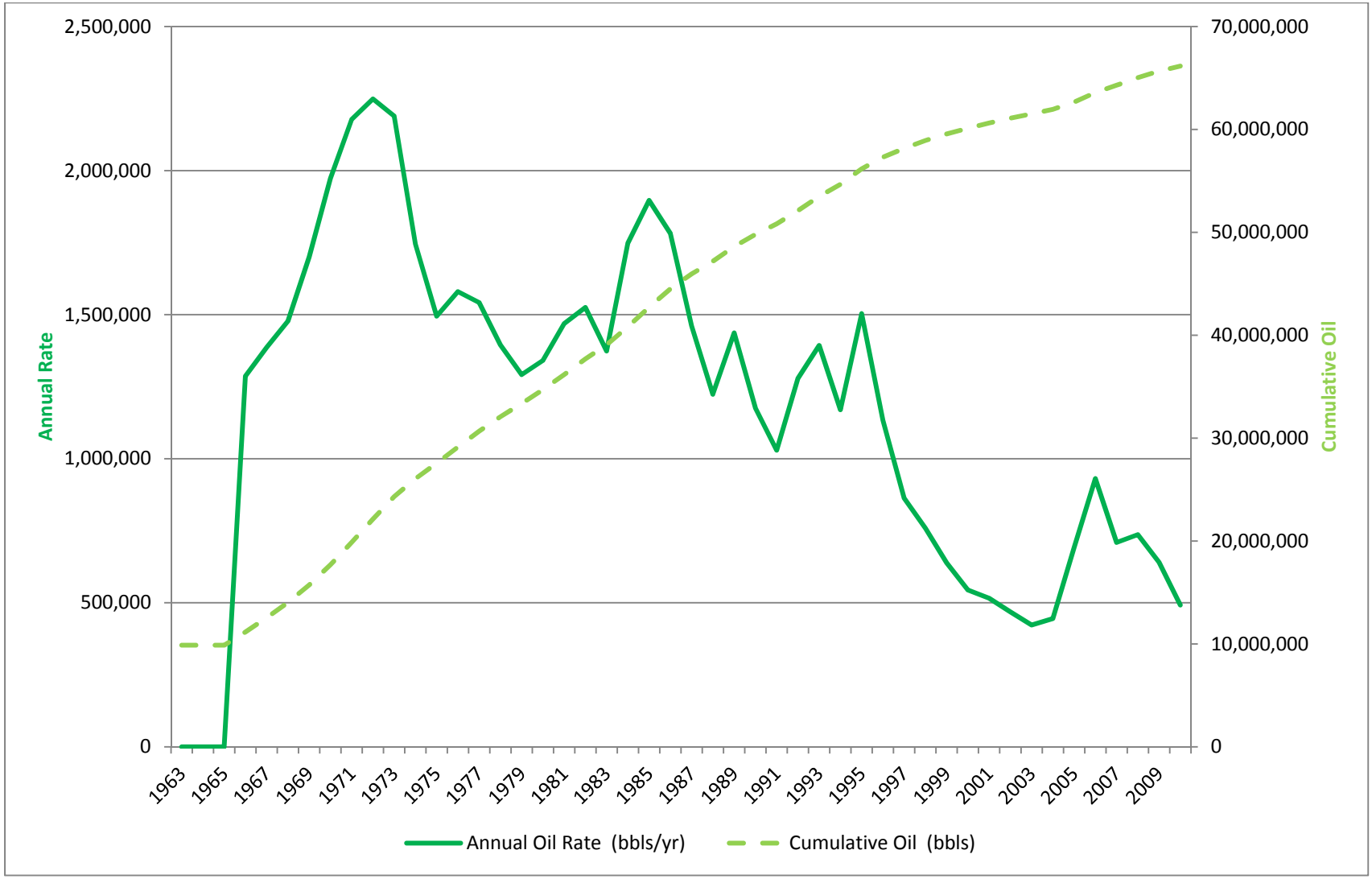


Figure 15. Annual and cumulative gas production from wells in the Cimarron and Comanche National Grasslands Study Area. Data from IHS Energy Group (2011).

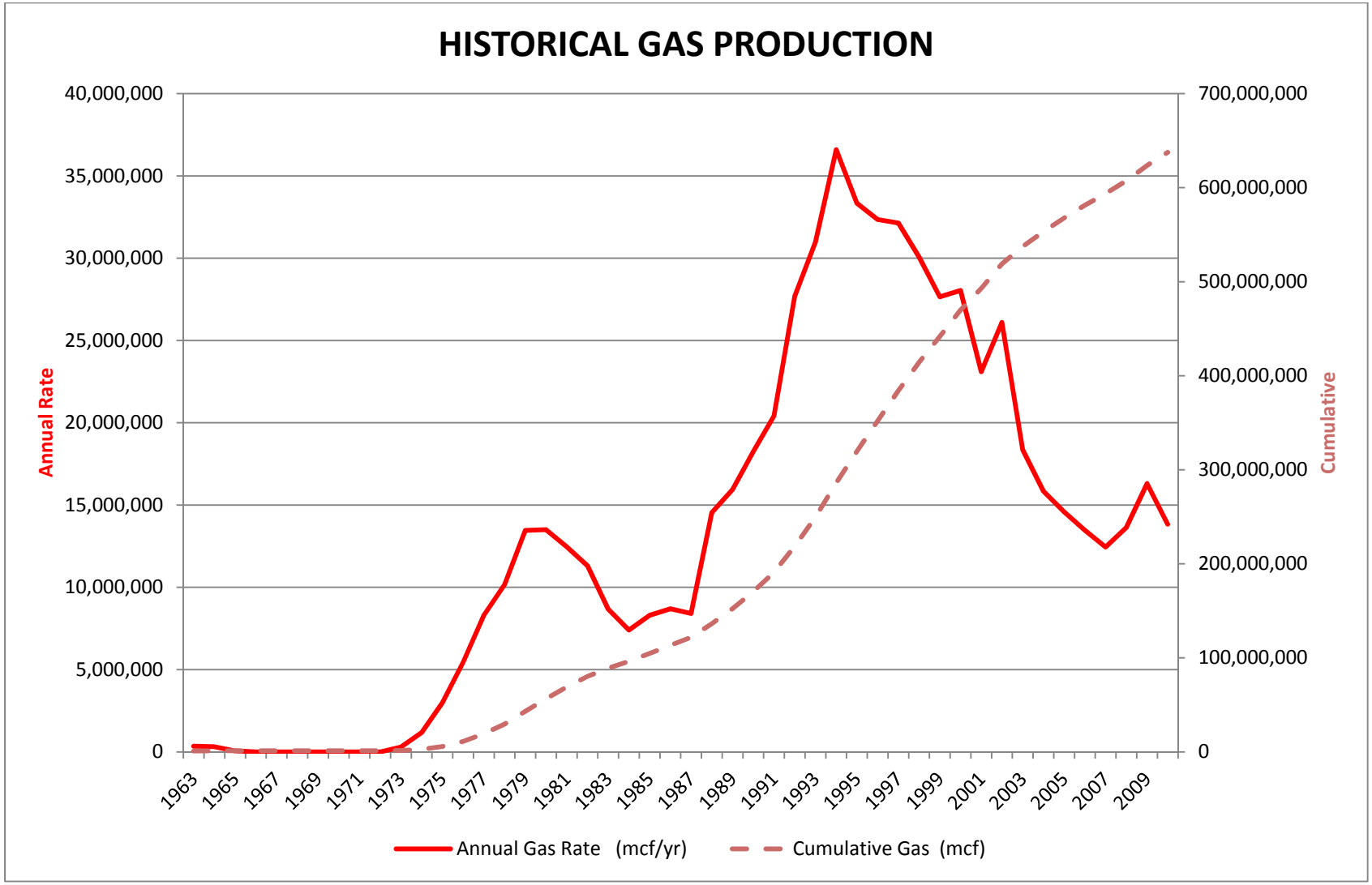


Figure 16. Annual and cumulative water production from wells in the Cimarron and Comanche National Grasslands Study Area. Data from IHS Energy Group (2011).

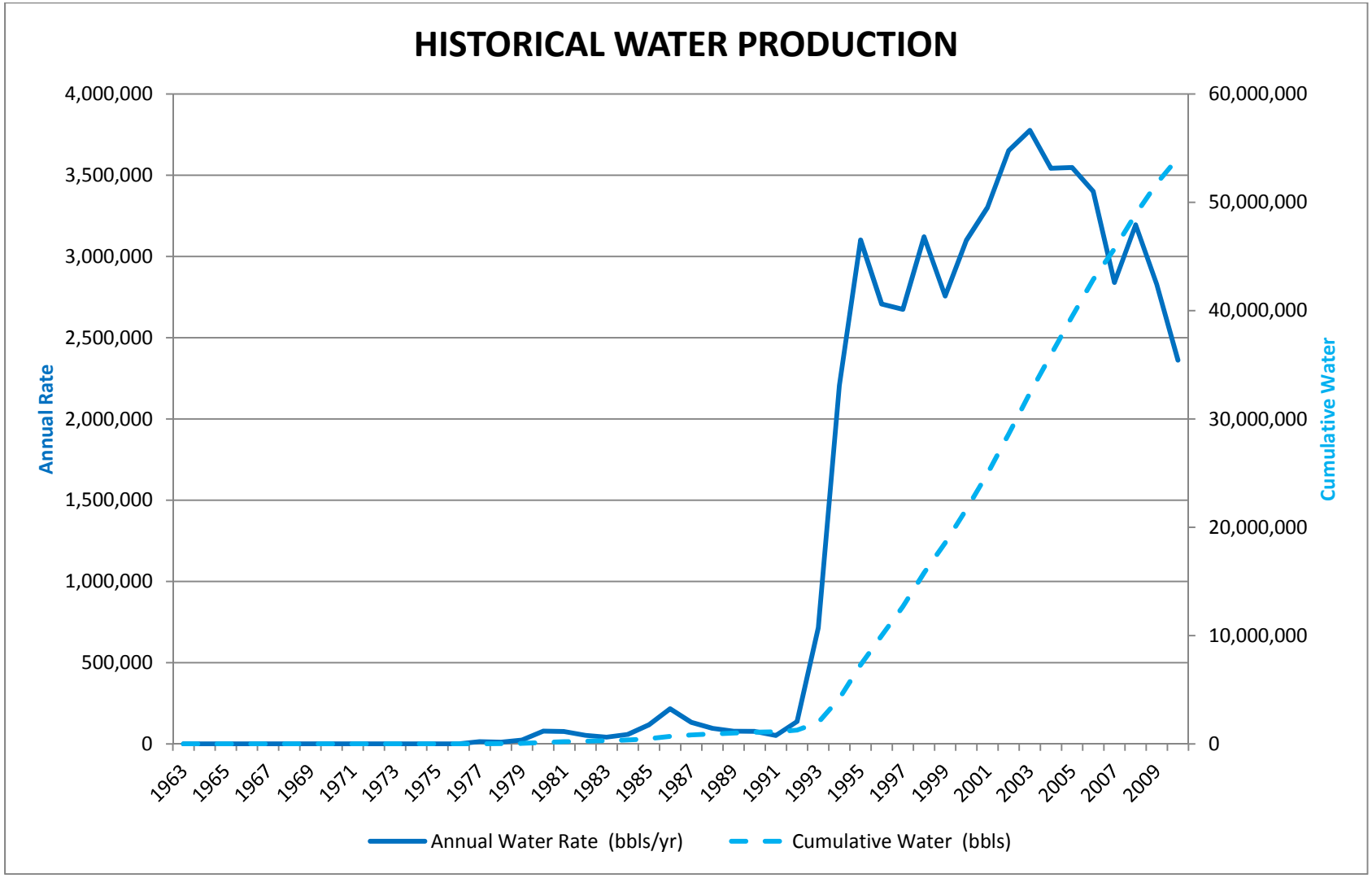
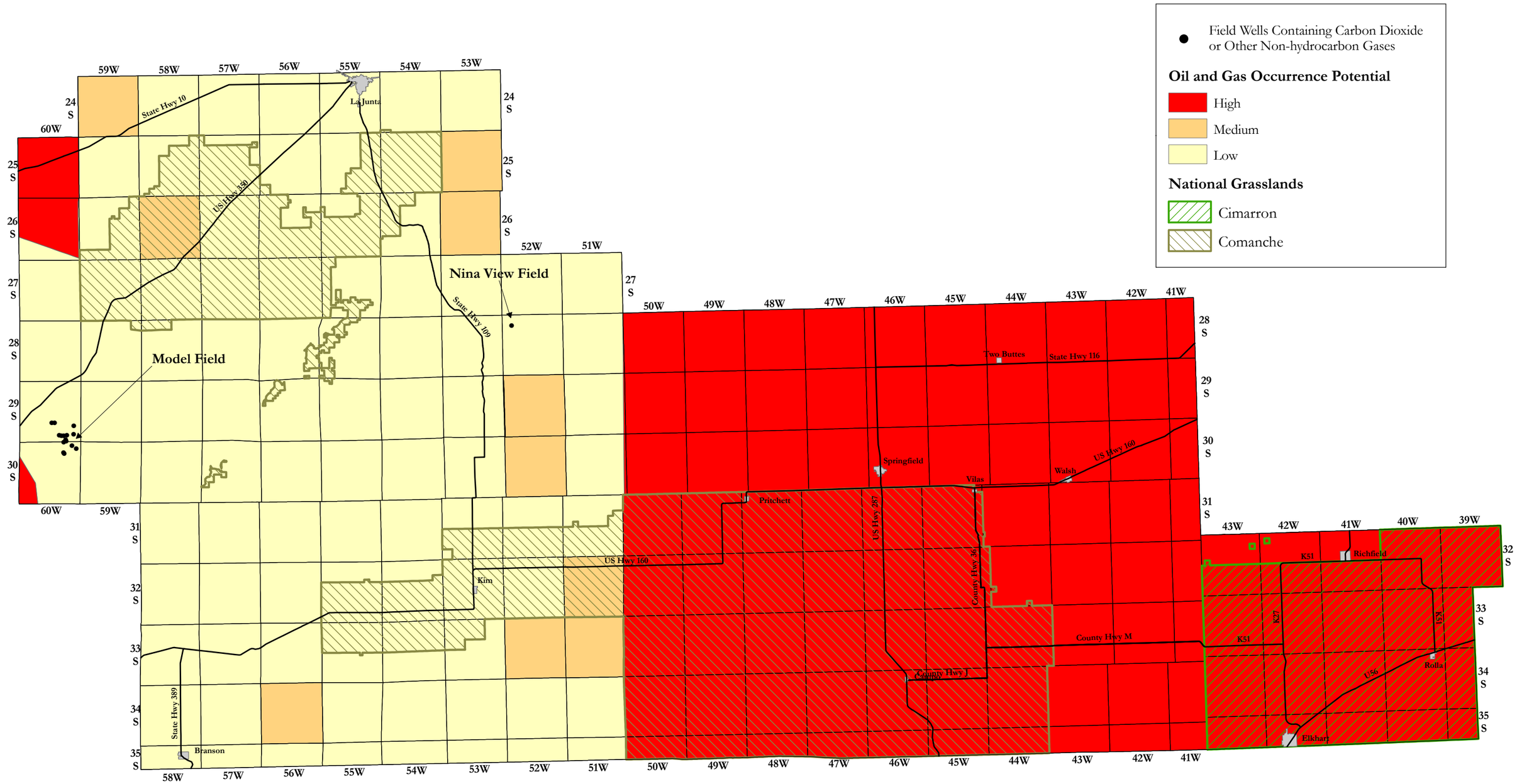


Figure 17.

Potential for occurrence of oil and gas and known carbon dioxide or other non-hydrocarbon gas wells in fields within the Cimarron and Comanche National Grasslands Study Area.



May, 2011

Dean P. Stilwell, Geologist
Al Elser, Geologist
Amber Robbins, Geologist

0 5 10 20 30 40 Miles

1:600,000

N

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 18. Colorado historical natural gas prices with future natural gas price projections (Energy Information Administration, 2011a).

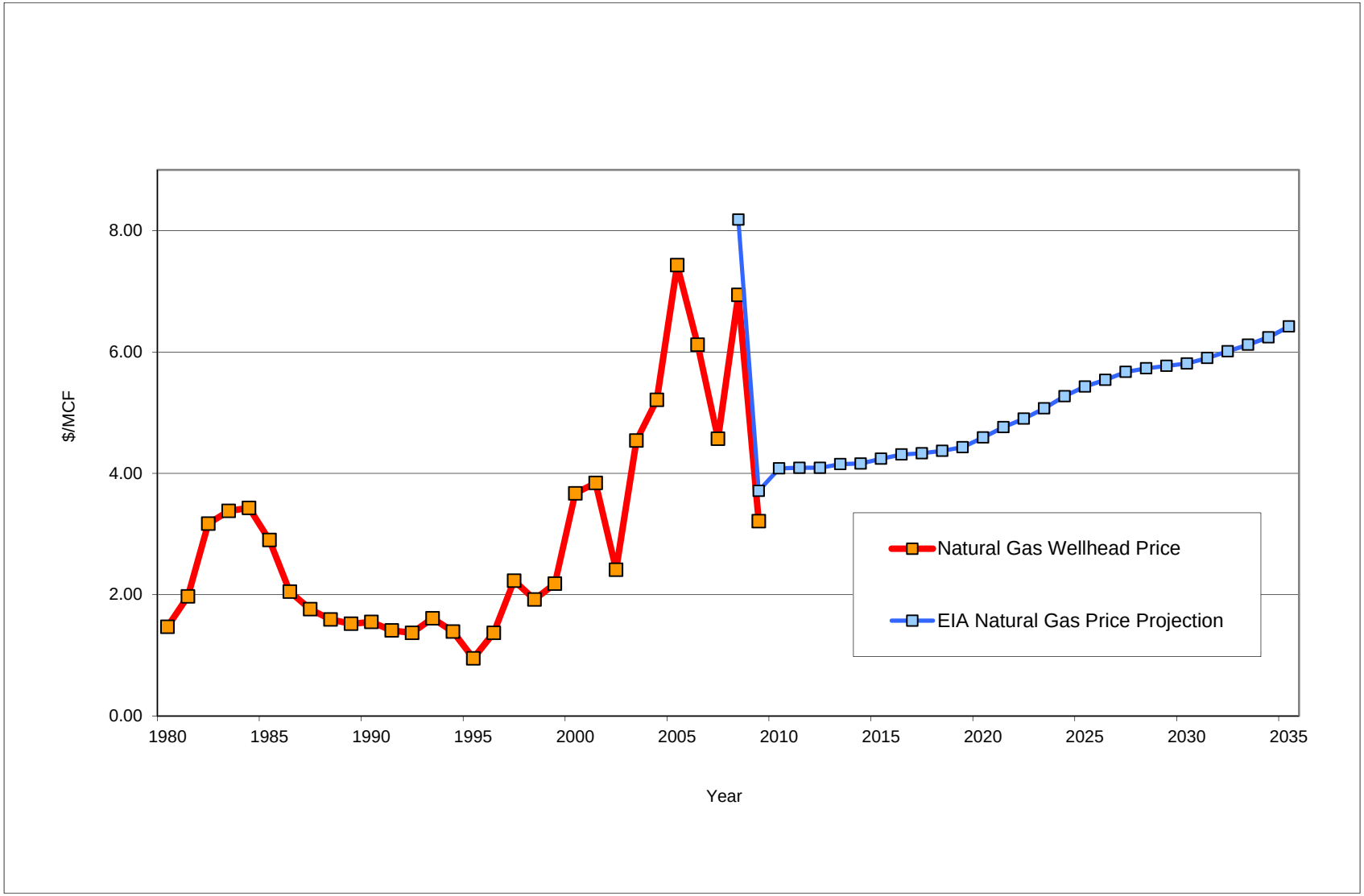


Figure 19. Kansas historical natural gas prices with future natural gas price projections (Energy Information Administration, 2011a).

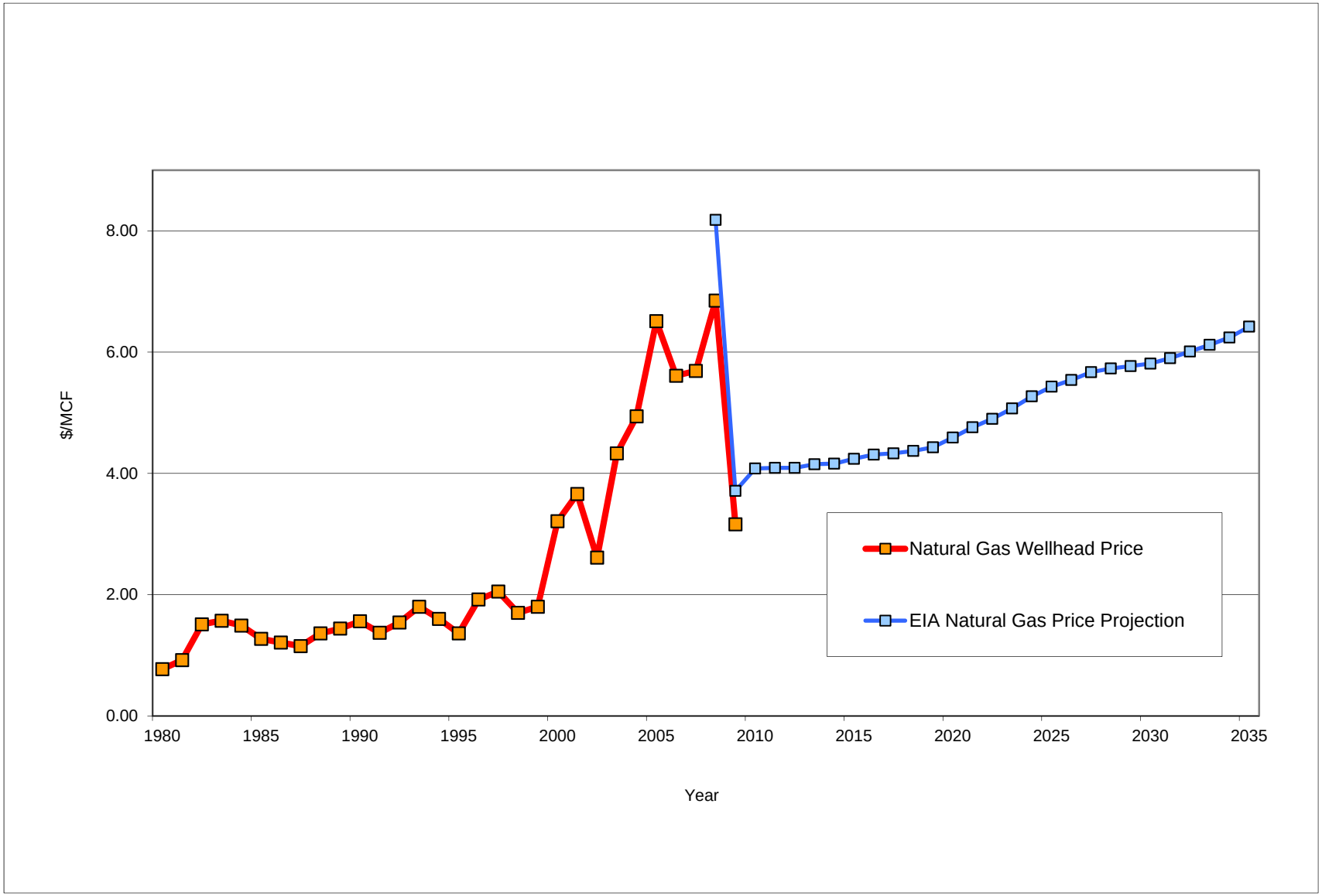


Figure 20. Colorado historical crude oil prices with future oil price projections (Energy Information Administration, 2011a).

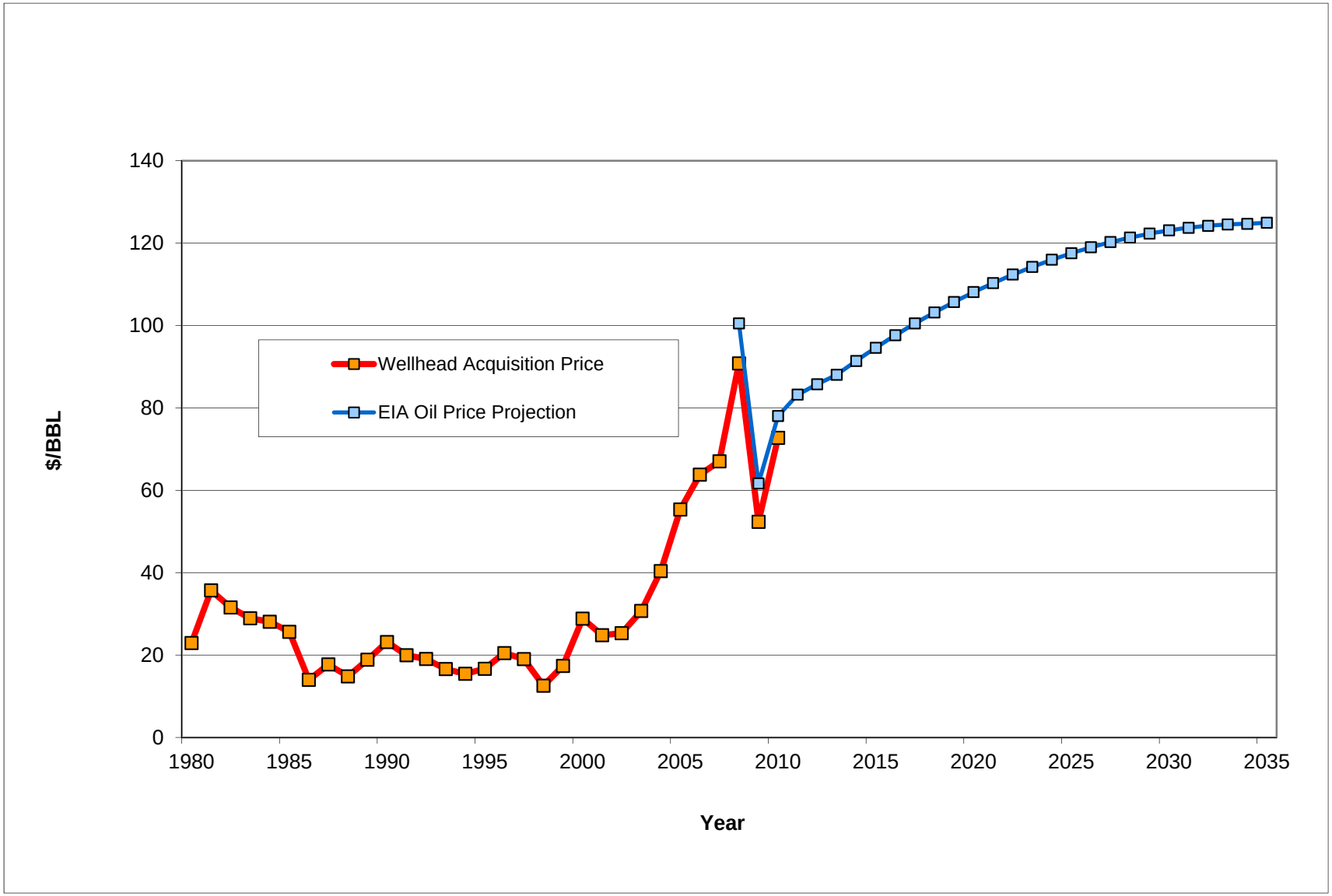


Figure 21. Kansas historical crude oil prices with future oil price projections (Energy Information Administration, 2011a).

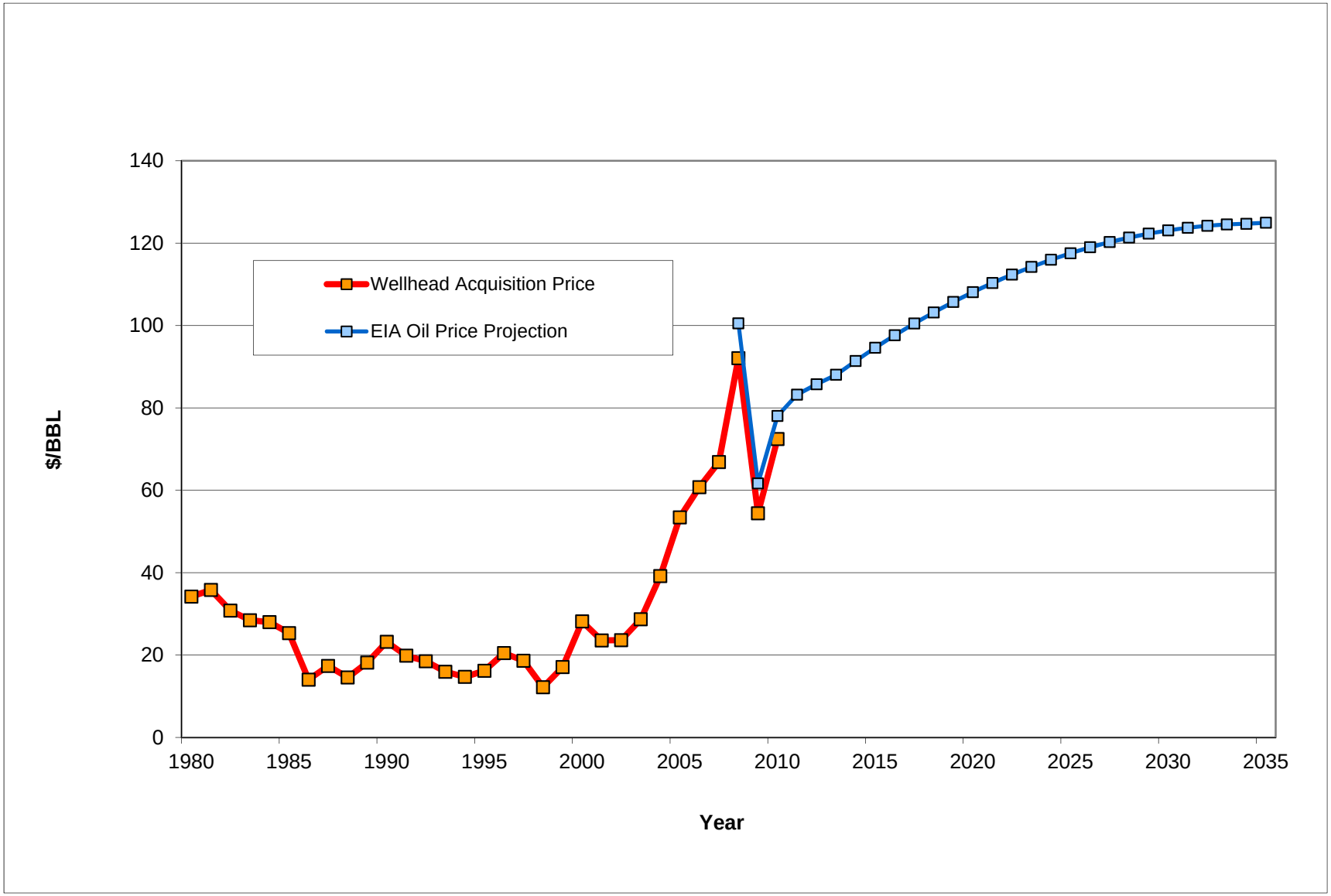
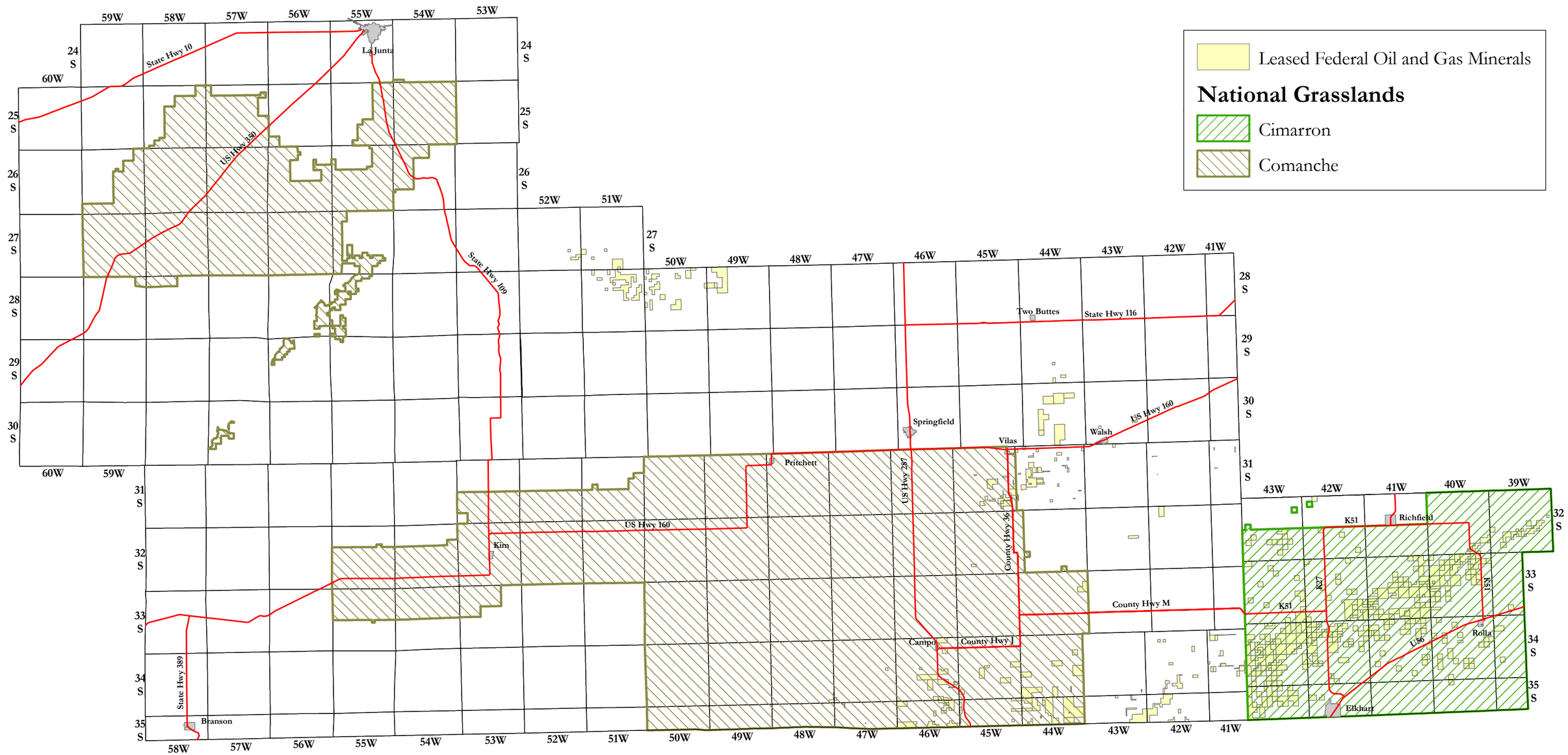


Figure 22.
Leased Federal oil and gas minerals within the Cimarron and Comanche National Grasslands Study Area. Data from Bureau of Land Management files and Premier Data Services.

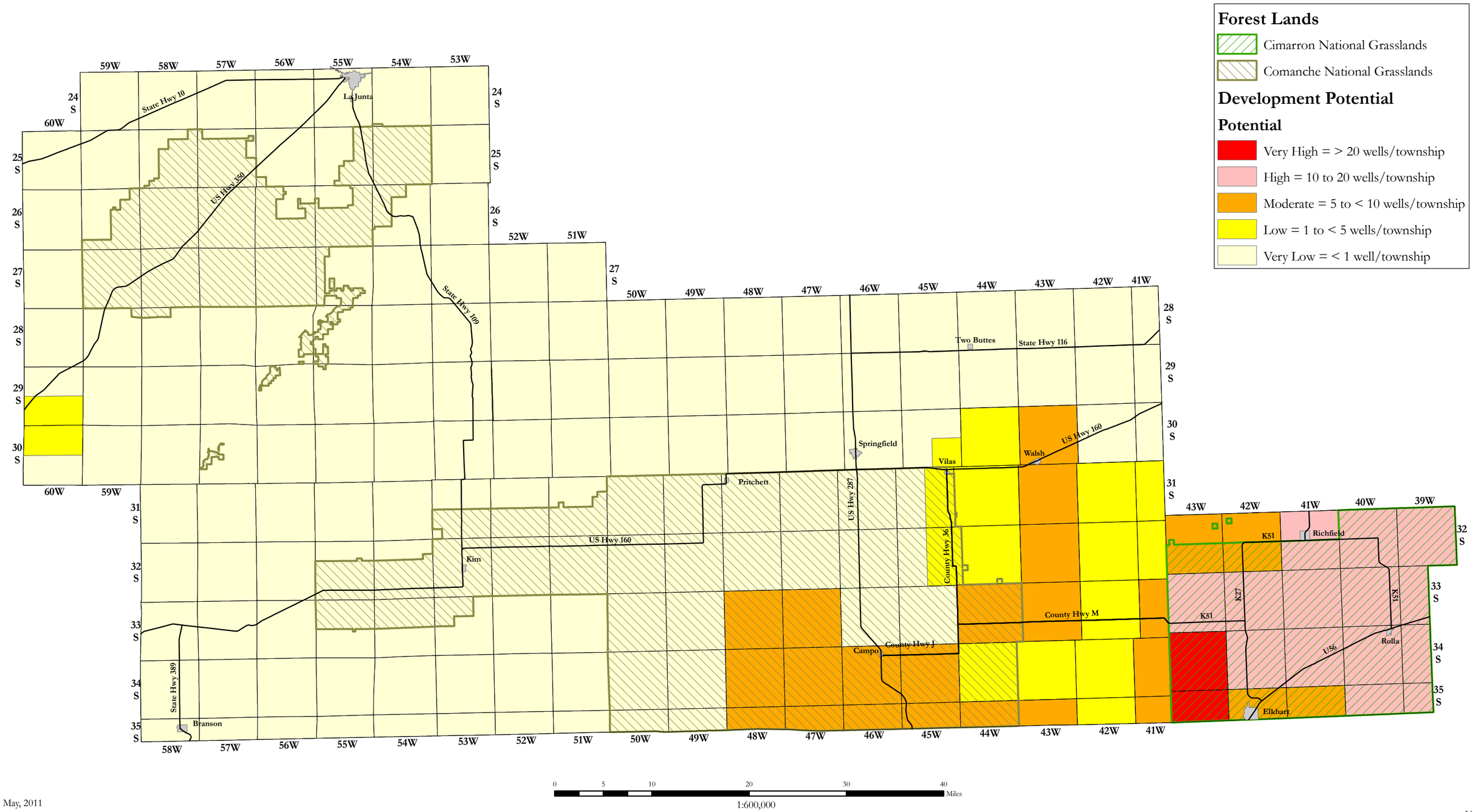


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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.
This map is printed in cooperation with Premier Data Services, Arvada Colorado.

Figure 23.
Oil and gas development potential and projected drilling densities within the Cimarron and Comanche National Grasslands Study Area for 2011 through 2030.



May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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.

Table 1. Federal oil and gas unit agreement data for the Cimarron and Comanche National Grasslands Study Area. Data from Bureau of Land Management files and Premier Data Services.

Unit Name	Grassland	Operator	Unitized Formation	Effective Date	Calculated Unit Acres
Lansing D	Comanche	Oxy USA Inc.	Lansing D	7/1/1997	480
SE Campo	Comanche	Murfin Drilling Co.	Lansing C	8/1/1993	1,341
Tanner	Comanche	Cheyenne Oil Properites Inc.	Lansing C	3/1/1991	760
Berryman-Richfield	Cimarron	Ladd Petroleum Corp.	Morrow	6/1/1975	4,667
Interstate Purdy-Morrow	Cimarron	Chaparral Energy LLC	Purdy Sand (Morrow)	4/1/1965	3,768
Santa Fe Trail A	Cimarron	Anadarko Prod. Corp.	Upper Morrow B	11/1/1984	752
Santa Fe Trail B	Cimarron	Anadarko Prod. Corp.	Upper Morrow B	5/16/1984	1,266
Stirrup	Cimarron	Merit Energy Co.	Upper Morrow	4/1/2003	2,832
Wilburton Morrow C	Cimarron	Oxy USA Inc.	Morrow C	1/29/1987	3,871
					19,737

Table 2.

Estimated oil and gas development potential classification acres, townships, average drilling densities, and percent within the Cimarron and Comanche National Grasslands Study Area.

Development Potential	Cimarron National Grassland Acres	Comanche National Grassland Acres	Non Forest Service Acres	Cimarron National Grassland Townships	Comanche National Grassland Townships	Non Forest Service Townships	Average Wells per Township	% of Study Area
Very High	34,714	0	27	1.51	0.00	0.00	50.0	0.81
High	260,021	0	11,592	11.29	0.00	0.50	15.0	6.33
Moderate	47,538	212,622	157,581	2.06	9.23	6.84	7.0	9.73
Low	0	49,014	251,215	0.00	2.13	10.90	3.0	6.99
Very Low	0	855,220	2,412,661	0.00	37.12	104.72	0.2	76.14
Study Area Totals	**342,273**	**1,116,856**	**2,833,077**	**14.86**	**48.47**	**122.96**		**100**

Table 3. Projected annual and cumulative oil and gas production from new wells projected for the Analysis Period in the Cimarron and Comanche National Grasslands Study Area.

	OIL (barrels)		GAS (thousand cubic feet)	
Year	**Annual**	**Cumulative**	**Annual**	**Cumulative**
2011	59,480	59,480	1,023,688	1,023,688
2012	110,688	170,168	1,971,715	2,995,403
2013	140,505	310,673	2,118,899	5,114,302
2014	173,339	484,013	2,952,827	8,067,129
2015	188,790	672,802	2,803,773	10,870,902
2016	204,134	876,937	3,208,160	14,079,062
2017	218,534	1,095,471	3,472,481	17,551,543
2018	229,133	1,324,604	3,572,907	21,124,450
2019	246,487	1,571,092	4,209,526	25,333,976
2020	245,525	1,816,616	3,505,342	28,839,318
2021	258,609	2,075,226	4,307,166	33,146,484
2022	260,847	2,336,072	4,021,770	37,168,254
2023	254,372	2,590,444	3,390,058	40,558,312
2024	261,986	2,852,429	3,842,815	44,401,126
2025	261,016	3,113,446	3,534,090	47,935,216
2026	261,107	3,374,553	3,561,785	51,497,001
2027	255,624	3,630,177	2,983,553	54,480,554
2028	248,509	3,878,686	2,440,663	56,921,217
2029	254,522	4,133,208	2,885,866	59,807,082
2030	254,941	4,388,149	2,783,860	62,590,942

Table 4.

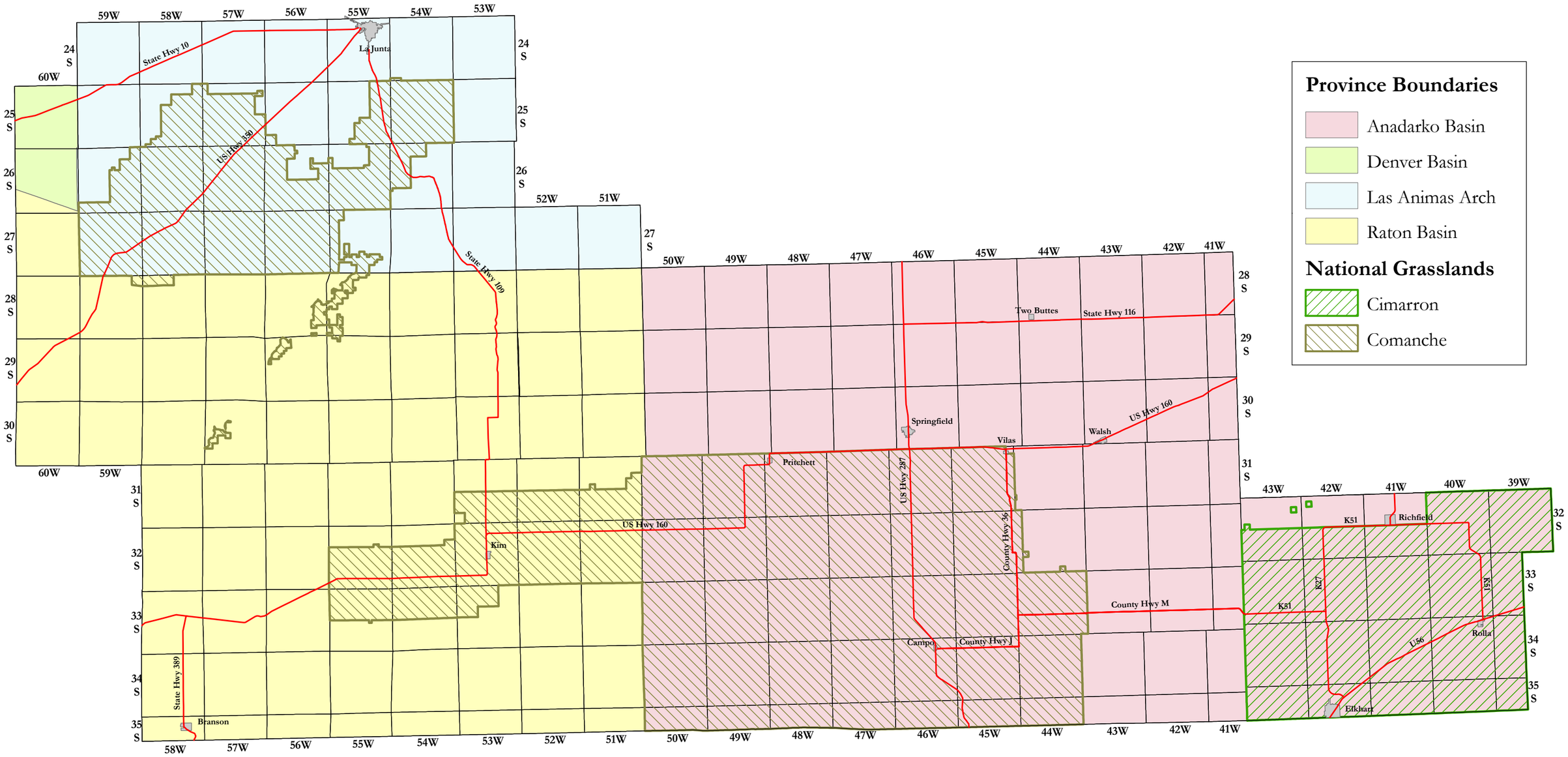
Cimaron and Comanche National Grasslands Study Area disturbance associated with wells projected for the base line development scenario for the 2011-2030 period and for existing active wells.

Disturbance Associated With All New Drilled Wells and Existing Active Wells (Short-Term Disturbance)							
Wells				**Acres of Surface Disturbance**			
Type	**All Lands**	**Cimarron National Grasslands**	**Comanche National Grasslands**	**Well Pads + Access Roads & Pipelines**	**All Lands**	**Cimarron National Grasslands**	**Comanche National Grasslands**
New Oil and Gas Wells	447	259	78	4.57	2,043	1,184	356
Existing Wells	1,765	1,459	40	0.68	1,200	992	27
Total Wells:	***2,212***	***1,718***	***118***	***Total Disturbance:***	***3,243***	***2,176***	***384***

Disturbance Associated With All New Producing Wells and Existing Active Wells Less Abandonments (Long-Term Disturbance)							
Wells				**Acres of Surface Disturbance**			
Type	**All Lands**	**Cimarron National Grasslands**	**Comanche National Grasslands**	**Well Pads + Access Roads & Pipelines**	**All Lands**	**Cimarron National Grasslands**	**Comanche National Grasslands**
New Oil and Gas Wells	313	181	55	4.20	1,314	761	229
Existing Wells	1,438	1,181	32	0.68	978	803	22
Total Wells:	***1,751***	***1,362***	***87***	***Total Disturbance:***	***2,292***	***1,565***	***251***

Figure A1-1.

Location of the Raton Basin 2007, Denver Basin 2007, Anadarko Basin 1995, and Las Animas Arch 1995 province boundaries within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



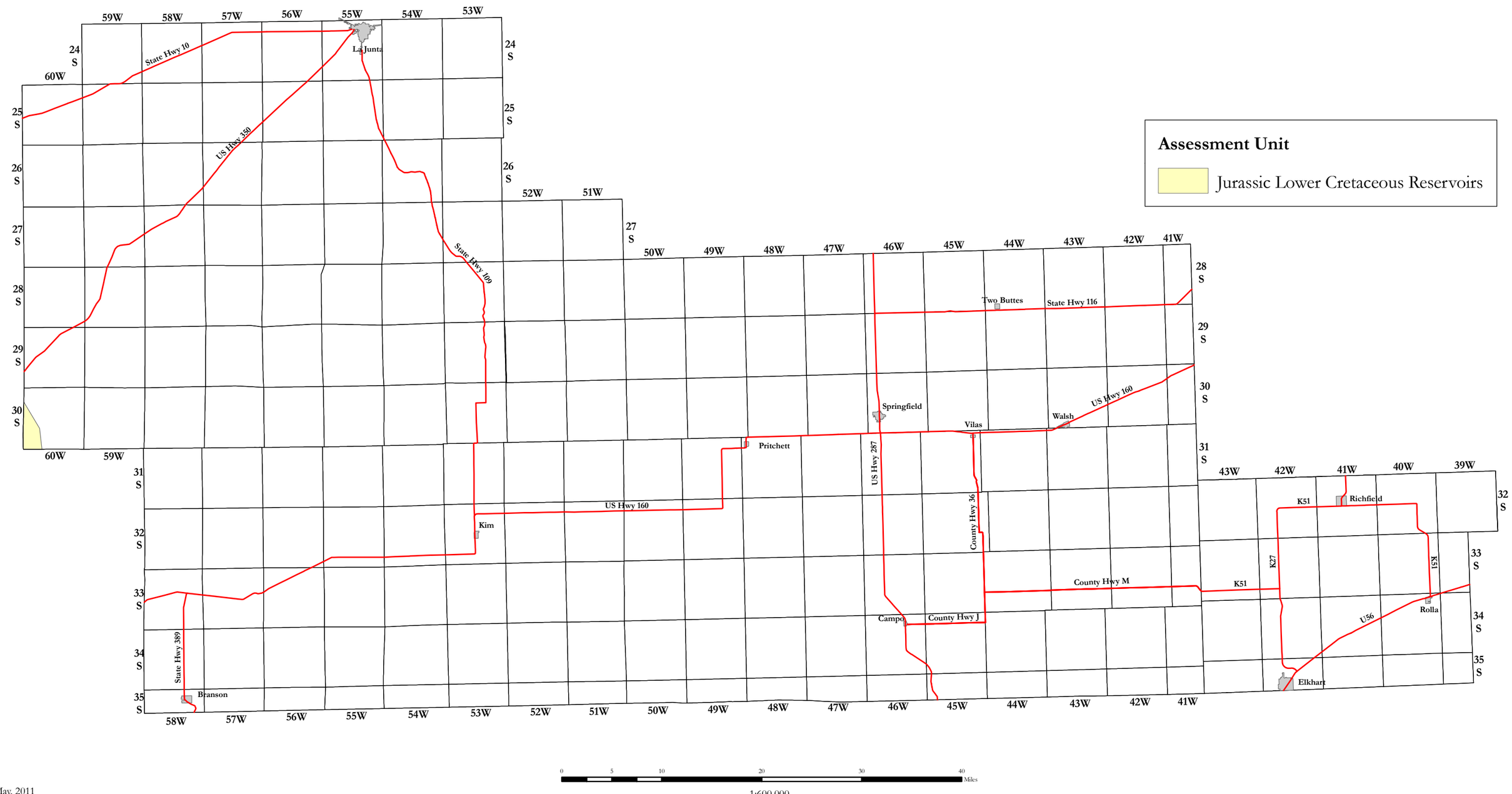
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-2.

Location of the 2007 Raton Basin Province Jurassic-Cretaceous Composite Total Petroleum System, Jurassic Lower Creetaceous Reservoirs within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



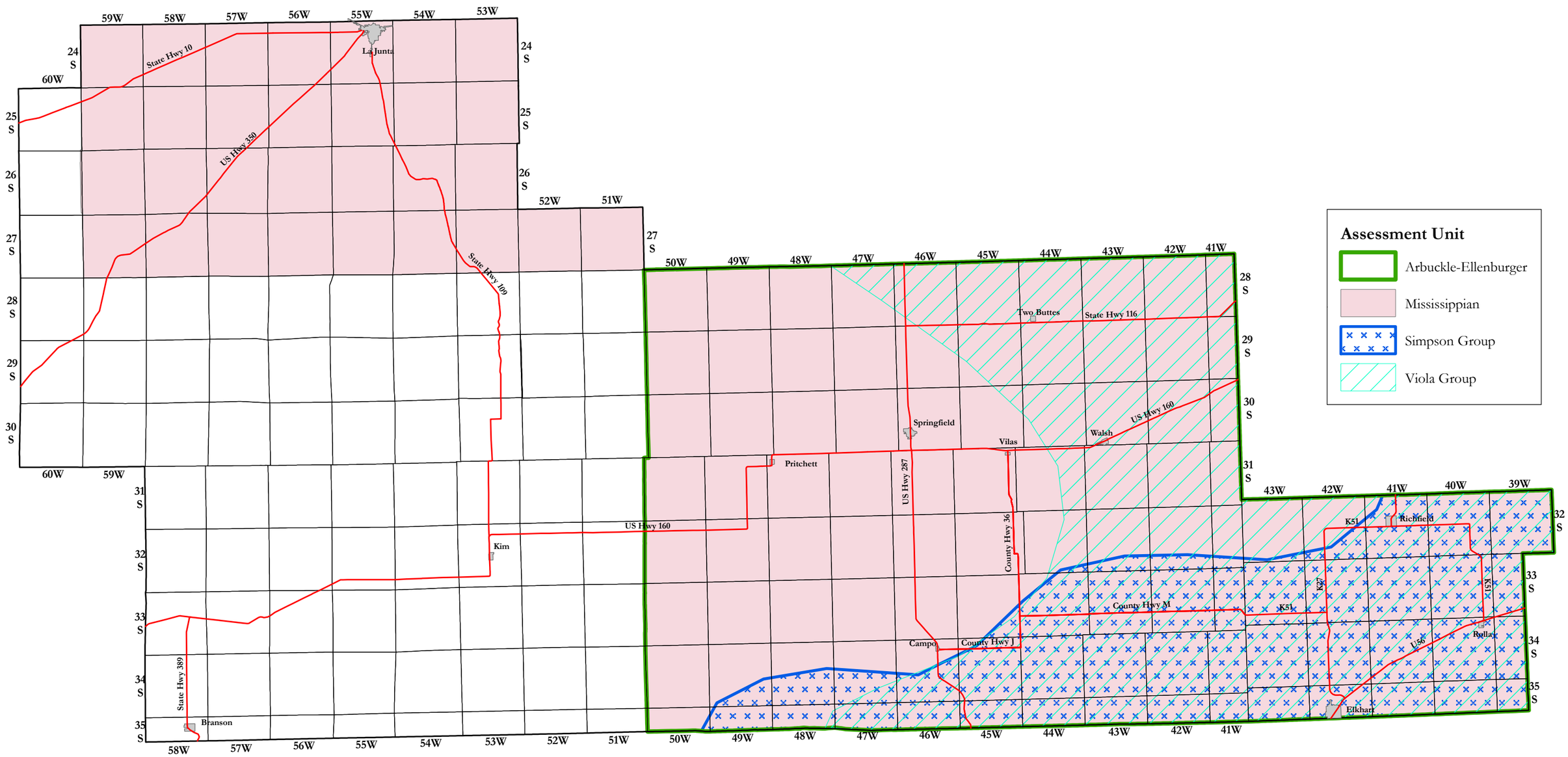
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-3.

Location of the 2011 Anadarko Basin Province Woodford Composite Total Petroleum System assessment units within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



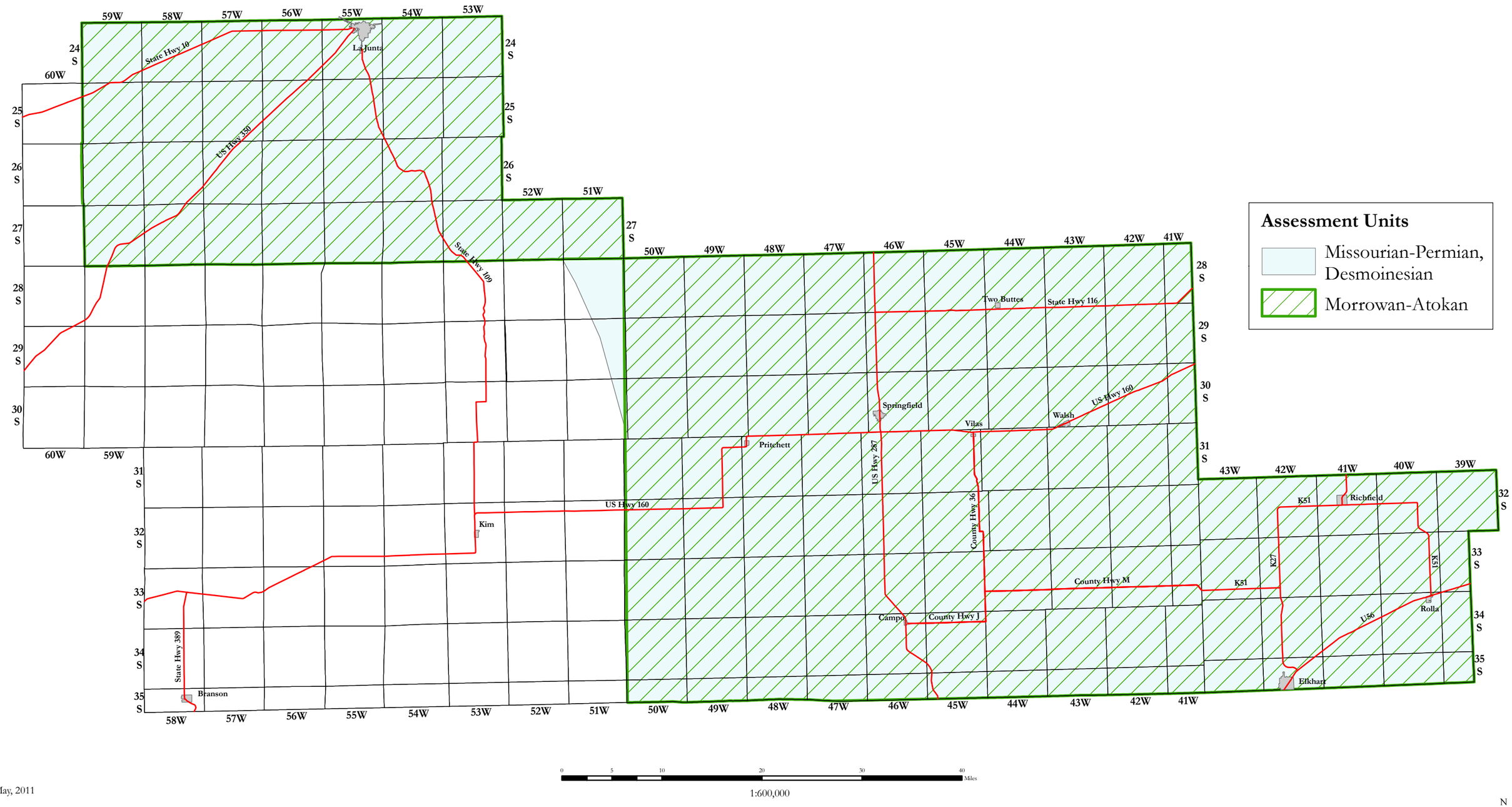
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-4.

Location of the 2011 Anadarko Basin Province Pennsylvanian Composite Total Petroleum System assessment units within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).

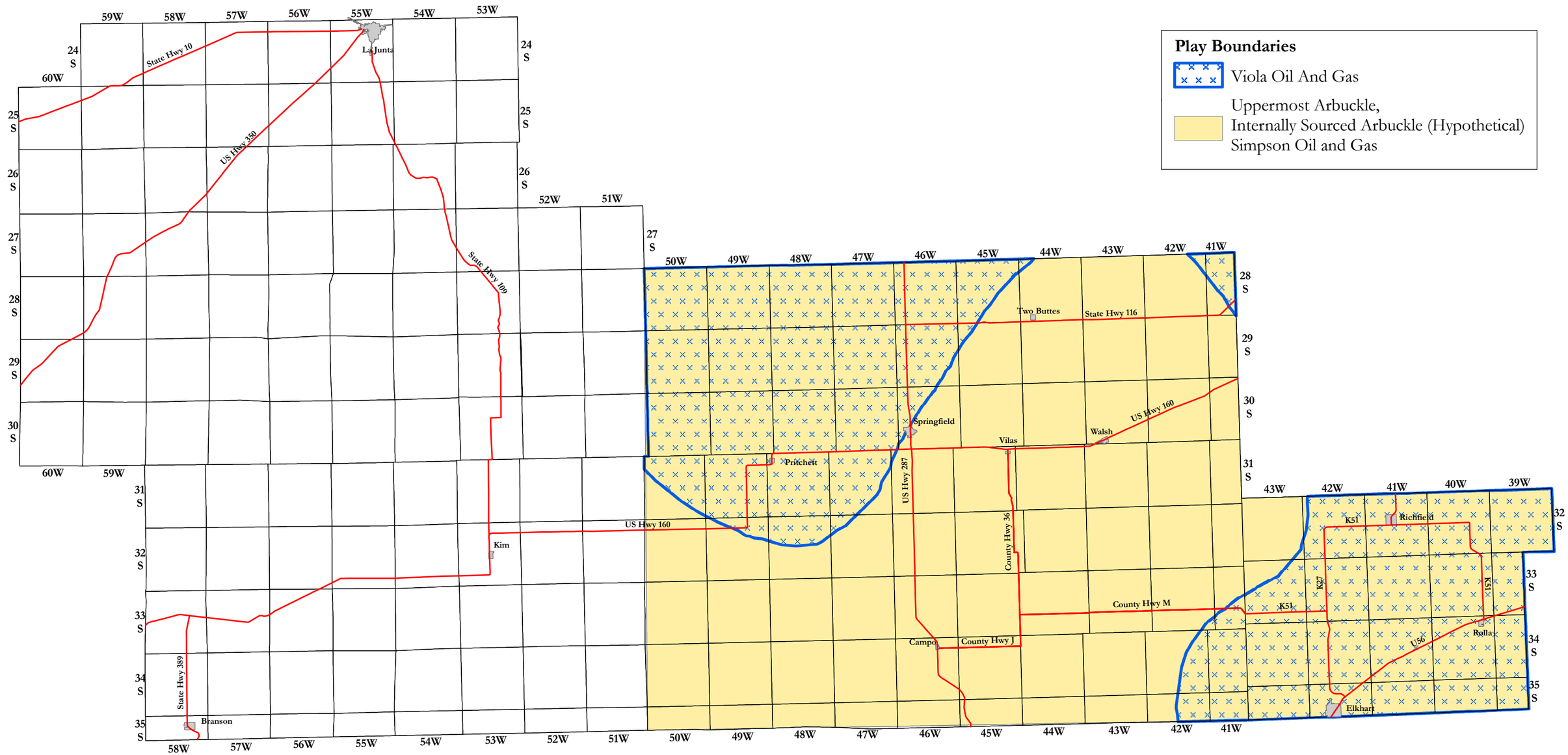


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-5.
Location of the 1995 Anadarko Basin Province Ordivician play boundaries within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).

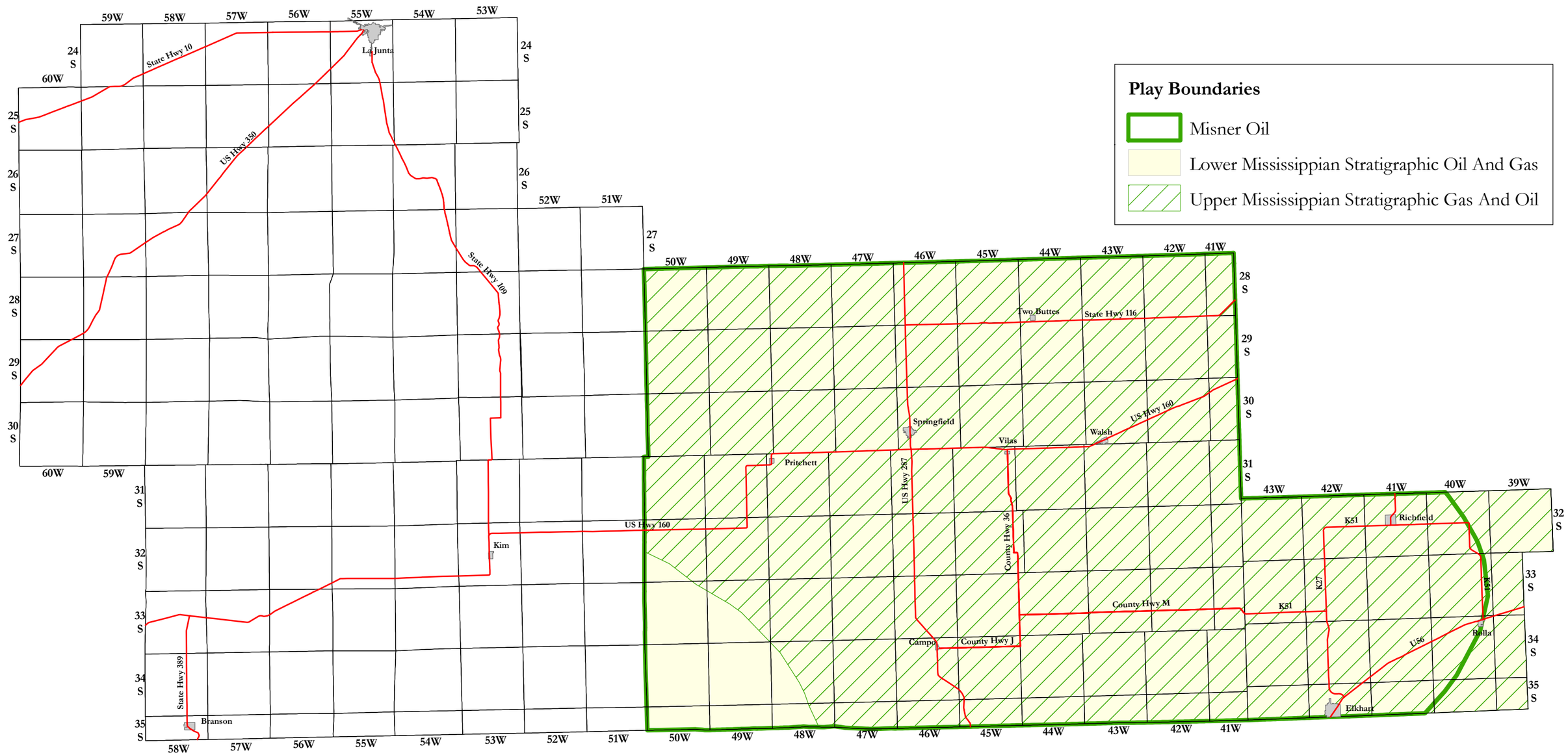


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-6.
Location of the 1995 Anadarko Basin Province Devonian-Mississippian play boundaries within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).

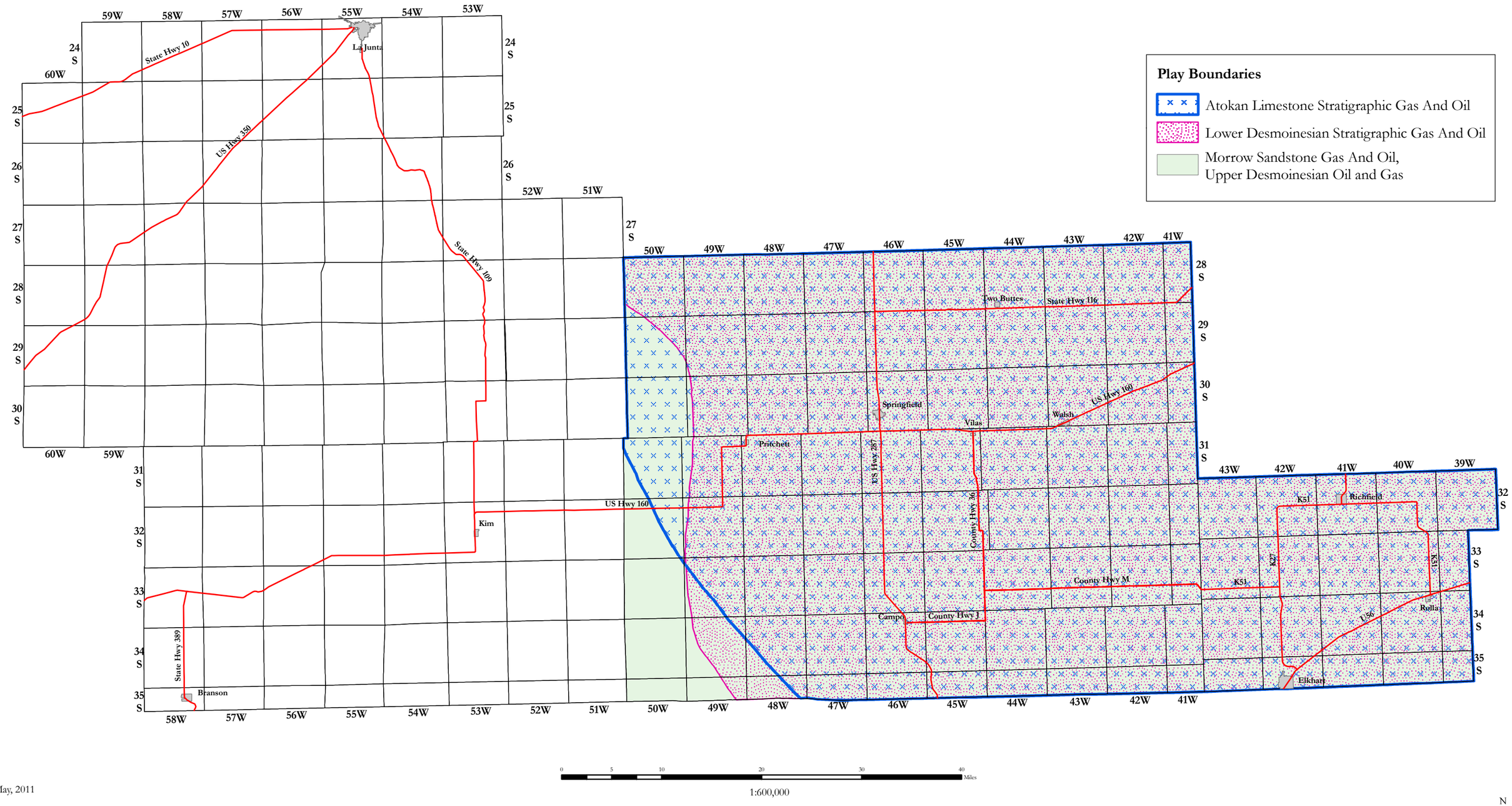


May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-7.
Location of the 1995 Anadarko Basin Province Lower Pennsylvanian play boundaries within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



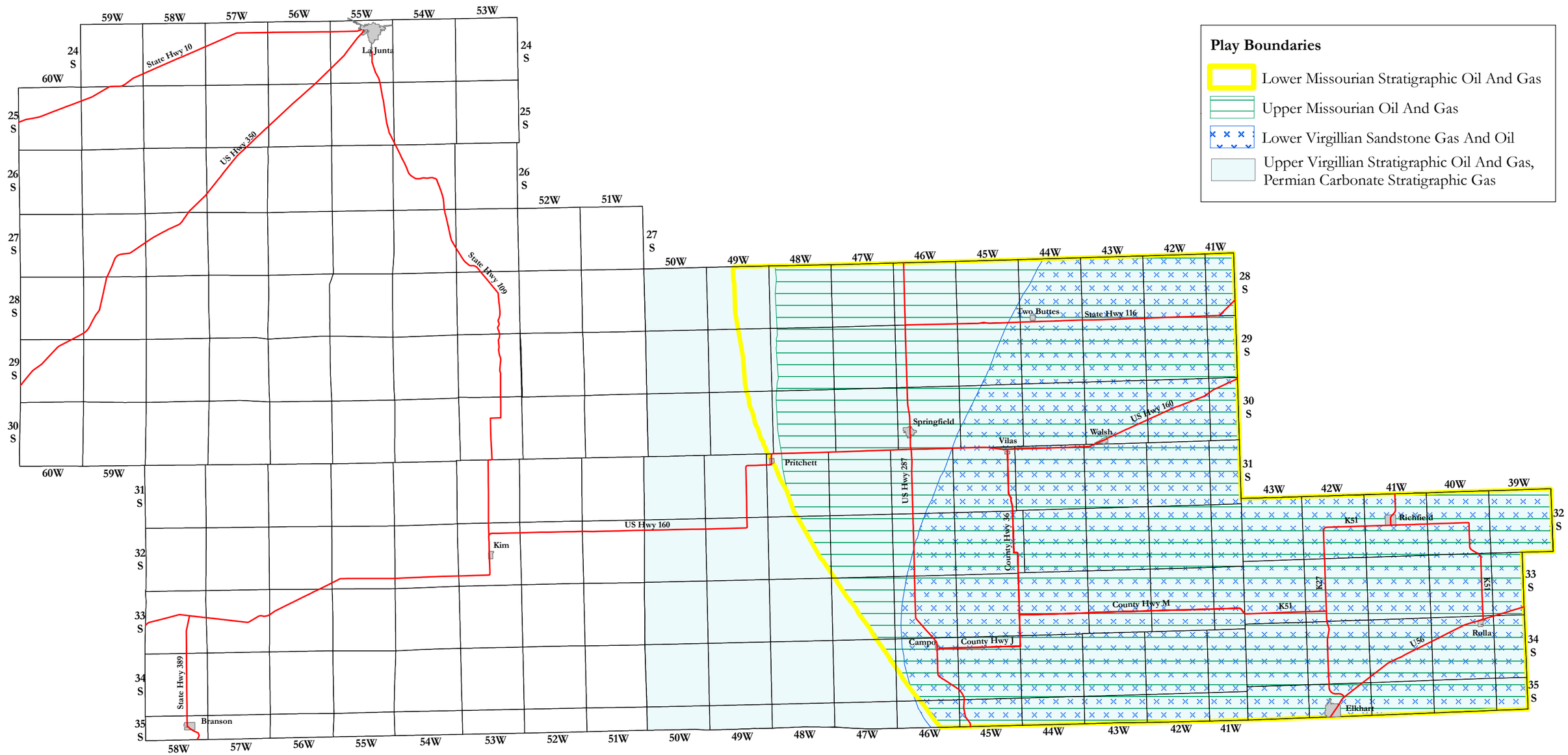
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-8.

Location of the 1995 Anadarko Basin Province Upper Pennsylvanian-Permian play boundaries within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



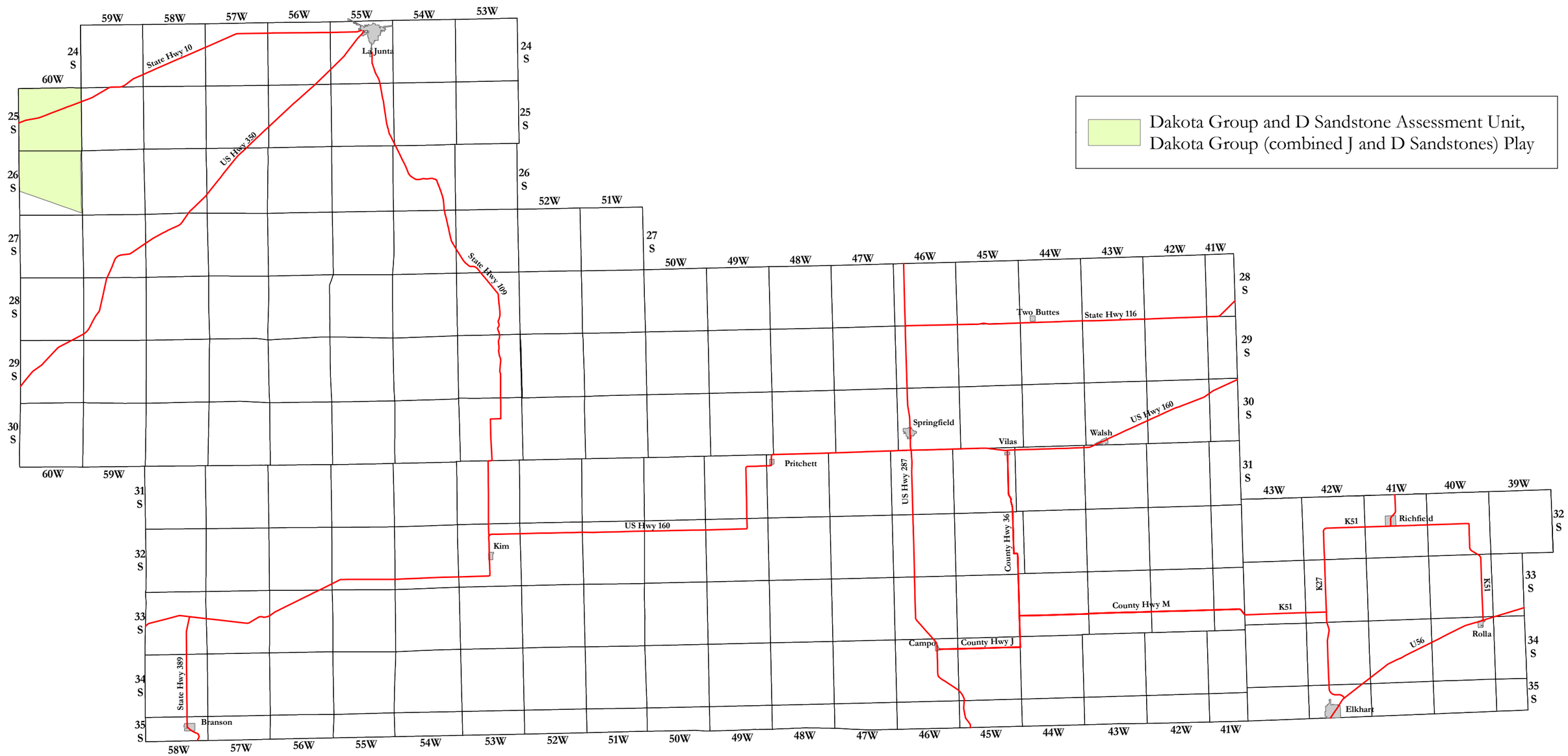
May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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 A1-9.

Location of the 2007 Denver Basin Province Lower Cretaceous Total Petroleum System (assessment unit and play) within the Cimarron and Comanche National Grasslands Study Area. Data from the United States Geological Survey (2011).



May, 2011

Dean P. Stilwell, Geologist
Al Elser, 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.

Table A1-1.

Data for U.S. Geological Survey 2007 assessment of undiscovered conventional accumulation assessment units, Raton Basin Province, Cimarron and Comanche National Grasslands Study Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Assessment Unit Name	**Exploration Status**	**Number Range**	**Mean Size (MMBO)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (feet)**
Jurassic-Lower Cretaceous Reservoirs	Hypothetical	0-0	N/A	N/A	N/A	1-120	6.0	150-3000

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

N/A = Not Applicable

(Higley et al., 2007)

Table A1-2.

U.S. Geological Survey 2007 estimated undiscovered technically recoverable resource quantities, Raton Basin Province, Cimarron and Comanche National Grasslands Study Area.

			Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Raton Basin Province										Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Study Area[1]								
			Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Assessment Unit Name		**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**% of Assessment Unit Lying Within Study Area**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**
Conventional Resources	Jurassic-Lower Cretaceous Reservoirs	Gas	0.00	0.00	0.00	184.48	1,073.12	615.09	0.00	46.45	24.58	0.13	0.00	0.00	0.00	0.24	1.40	0.80	0.00	0.06	0.03
	Total Undiscovered Conventional Resource		**0.00**	**0.00**	**0.00**	**184.48**	**1,073.12**	**615.09**	**0.00**	**46.45**	**24.58**		**0.00**	**0.00**	**0.00**	**0.24**	**1.40**	**0.80**	**0.00**	**0.06**	**0.03**

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 assessment unit.

Modified from Higley et al., 2007 for the Study Area

Table A1-3.

U.S. Geological Survey 2011 estimated undiscovered technically recoverable resources for assessment units, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.

			Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Anadarko Basin Province										Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Study Area[1]								
			Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
	Assessment Unit Name		**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**% of Assessment Unit Lying Within Study Area**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**
Conventional Resources	Arbuckle-Ellenburger	**Oil**	2	12	6	7	61	28	0	2	1	4.98	0.10	0.60	0.30	0.35	3.04	1.39	0.00	0.10	0.05
		Gas				43	371	181	0	2	1		0.00	0.00	0.00	2.14	18.48	9.01	0.00	0.10	0.05
	Simpson Oil and Gas Play	Oil	2	9	5	6	39	19	0	1	1	2.05	0.04	0.18	0.10	0.12	0.80	0.39	0.00	0.02	0.02
		Gas				33	252	125	2	21	10		0.00	0.00	0.00	0.68	5.17	2.56	0.04	0.43	0.21
	Mississippian	Oil	5	31	17	15	99	50	0	4	2	5.41	0.27	1.68	0.92	0.81	5.36	2.71	0.00	0.22	0.11
		Gas				125	663	367	3	17	9		0.00	0.00	0.00	6.76	35.87	19.85	0.16	0.92	0.49
	Morrowan-Atokan	Oil	6	29	15	21	121	61	1	5	2	7.47	0.45	2.17	1.12	1.57	9.04	4.56	0.07	0.37	0.15
		Gas				101	469	271	2	10	5		0.00	0.00	0.00	7.54	35.03	20.24	0.15	0.75	0.37
	Desmoinesian	Oil	2	12	6	8	52	26	0	2	1	6.33	0.13	0.76	0.38	0.51	3.29	1.65	0.00	0.13	0.06
		Gas				29	167	92	1	5	3		0.00	0.00	0.00	1.84	10.57	5.82	0.06	0.32	0.19
	Viola Oil and Gas Play	Oil	2	10	5	3	20	10	0	2	1	2.99	0.06	0.30	0.15	0.09	0.60	0.30	0.00	0.06	0.03
		Gas				10	58	30	0	0	0		0.00	0.00	0.00	0.30	1.73	0.90	0.00	0.00	0.00
	Missourian-Permian	Oil	10	38	23	49	223	122	2	8	4	6.33	0.63	2.41	1.46	3.10	14.12	7.72	0.13	0.51	0.25
		Gas				61	231	136	2	7	4		0.00	0.00	0.00	3.86	14.62	8.61	0.13	0.44	0.25
	Total Undiscovered Conventional Resource		**29.00**	**141.00**	**77.00**	**511.00**	**2,826.00**	**1,518.00**	**13.00**	**86.00**	**44.00**		**1.68**	**8.09**	**4.43**	**29.67**	**157.71**	**85.72**	**0.74**	**4.36**	**2.23**

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

NGL = Natural Gas Liquids

MMBNGL = Million Barrels of Natural Gas Liquids

N/A = Not Applicable

[1] Potential resource is assumed to be evenly distributed across each play area or assessment unit.

Modified from Higley, 2011 for the Study Area

Wyoming State Office
Reservoir Management Group

Table A1-4.

Data for U.S. Geological Survey 1995 assessment of undiscovered conventional accumulation plays, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Play Name	**Exploration Status**	**Number Range**	**Mean Size (MMBOE)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (feet)**
Atokan Limestone Stratigraphic Gas and Oil Play	Confirmed	1-6	2.8	44	4,500-13,000	1-5	8.1	4,500-13,000
Internally Sourced Arbuckle Play (Hypothetical)	Confirmed	1-60	4		2,000-13,000	1-60	24.0	2,000-13,000
Lower Desmoinesian Stratigraphic Gas and Oil Play	Confirmed	1-8	2.8	48	4,000-13,000	10-50	98.8	4,000-13,000
Lower Mississippian Stratigraphic Oil and Gas Play	Confirmed	5-20	2.8	38	4,000-13,000	3-10	40.4	4,000-13,000
Lower Missourian Stratigraphic Oil and Gas Play	Confirmed	2-20	3.1	47	4,000-12,000	2-15	27.4	4,000-12,000
Lower Virgilian Sandstone Gas and Oil Play	Confirmed	1-5	2.8	48	3,000-11,500	4-20	25.0	3,000-11,500
Misener Oil Play	Confirmed	2-10	4.1		5,000-13,000	0		
Morrow Sandstone Gas and Oil Stratigraphic Play	Confirmed	5-25	5	47	4,200-13,000	12-65	35.0	4,200-13,000
Permian Carbonate Stratigraphic Gas Play	Confirmed	0		46.7		1-4	11.3	700-4,900
Simpson Oil and Gas Play	Confirmed	1-5	2.4	46	4,000-13,000	1-5	8.9	4,000-13,000
Upper Desmoinesian Oil and Gas Play	Confirmed	2-10	3.1	40	4,000-13,000	1-6	18.0	4,000-13,000
Upper Mississippian Stratigraphic Gas and Oil Play	Confirmed	4-15	4.5	44	4,000-13,000	5-20	19.7	4,000-13,000
Upper Missourian Oil and Gas Play	Confirmed	1-5	2.5	41	4,000-12,000	1-3	12.1	4,000-12,000
Upper Virgilian Stratigraphic Oil and Gas Play	Confirmed	1-3	2.5	40	2,300-9,000	1-6	24.7	2,300-9,000
Uppermost Arbuckle Play	Confirmed	1-10	1.9	40	4,000-13,000	1-10	13.1	4,000-13,000
Viola Oil and Gas Play	Confirmed	1-3	2.8		4,000-13,000	1-3	10.2	4,000-13,000

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

N/A = Not Applicable or Not Available

(Modified from Henry and Hester, 1995)

Table A1-5.

U.S. Geological Survey 1995 estimated undiscovered technically recoverable resource quantities for plays, Anadarko Basin Province, Cimarron and Comanche National Grasslands Study Area.

		Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Raton Basin Province										Estimated Undiscovered Resources for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Study Area[1]								
		Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
Assessment Unit Name		**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**% of Assessment Unit Lying Within Study Area**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**	**95%**	**5%**	**Mean**
Atokan Limestone Stratigraphic Gas and Oil Play	Oil	1.50	19.80	8.90	10.05	132.66	59.60				9.98	0.15	1.98	0.89	1.00	13.24	5.95			
	Gas				6.20	41.30	19.90	0.60	7.06	3.20					0.62	4.12	1.99	0.06	0.70	0.32
Internally Sourced Arbuckle Play (Hypothetical)	Oil	0.00	92.50	11.30	0.00	9.25	1.10				7.23	0.00	6.69	0.82	0.00	0.67	0.08			
	Gas				0.00	563.60	67.50	0.00	4.97	0.60					0.00	40.74	4.88	0.00	0.36	0.04
Lower Desmoinesian Stratigraphic Gas and Oil Play	Oil	1.50	23.90	10.10	10.50	167.30	70.50				5.80	0.09	1.39	0.59	0.61	9.70	4.09			
	Gas				134.10	3813.70	2388.70	2.92	76.68	46.40					7.77	221.05	138.46	0.17	4.44	2.69
Lower Mississippian Stratigraphic Oil and Gas Play	Oil	2.90	43.40	30.50	22.04	329.84	232.00				6.75	0.20	2.93	2.06	1.49	22.27	15.66			
	Gas				18.10	354.90	228.40	1.57	25.72	17.50					1.22	23.96	15.42	0.11	1.74	1.18
Lower Missourian Stratigraphic Oil and Gas Play	Oil	2.00	55.80	23.40	6.00	167.40	70.20				4.78	0.10	2.67	1.12	0.29	8.00	3.36			
	Gas				18.10	375.60	177.20	0.84	19.76	8.80					0.87	17.96	8.47	0.04	0.94	0.42
Lower Virgilian Sandstone Gas and Oil Play	Oil	1.50	18.30	8.30	2.55	31.11	14.10				3.59	0.05	0.66	0.30	0.09	1.12	0.51			
	Gas				14.20	420.80	227.50	0.24	5.69	3.00					0.51	15.12	8.17	0.01	0.20	0.11
Misener Oil Play	Oil	2.10	37.80	19.70	2.73	49.14	25.60				63.03	1.32	23.82	12.42	1.72	30.97	16.14			
	Gas							0.14	2.46	1.30								0.09	1.55	0.82
Morrow Sandstone Gas and Oil Stratigraphic Play	Oil	9.50	103.70	75.00	64.60	705.16	510.20				8.87	0.84	9.20	6.66	5.73	62.58	45.28			
	Gas				112.40	1720.50	1173.70	2.83	36.86	25.80					9.98	152.69	104.17	0.25	3.27	2.29
Permian Carbonate Stratigraphic Gas Play	Oil										5.24									
	Gas				0.00	44.40	12.60	0.00	1.95	0.60					0.00	2.32	0.66	0.00	0.10	0.03
Simpson Oil and Gas Play	Oil	1.30	13.30	6.00	0.65	6.65	3.00				7.03	0.09	0.94	0.42	0.05	0.47	0.21			
	Gas				6.60	45.00	21.70	0.05	0.47	0.20					0.46	3.17	1.53	0.00	0.03	0.01
Upper Desmoinesian Oil and Gas Play	Oil	2.00	32.50	16.90	5.00	81.25	42.20				5.86	0.12	1.90	0.99	0.29	4.76	2.47			
	Gas				8.50	112.90	48.00	0.34	5.17	2.60					0.50	6.61	2.81	0.02	0.30	0.15
Upper Mississippian Stratigraphic Gas and Oil Play	Oil	2.10	55.40	33.90	11.76	310.24	189.70				6.22	0.13	3.45	2.11	0.73	19.31	11.80			
	Gas				21.30	308.90	218.00	0.82	18.60	11.70					1.33	19.22	13.57	0.05	1.16	0.73
Upper Missourian Oil and Gas Play	Oil	1.30	14.40	6.20	1.17	12.96	5.60				4.52	0.06	0.65	0.28	0.05	0.59	0.25			
	Gas				7.20	48.80	24.20	0.12	1.09	0.50					0.33	2.21	1.09	0.01	0.05	0.02
Upper Virgilian Stratigraphic Oil and Gas Play	Oil	1.30	10.70	5.10	2.08	17.12	8.10				7.23	0.09	0.77	0.37	0.15	1.24	0.59			
	Gas				9.80	158.60	65.70	0.18	1.76	0.80					0.71	11.46	4.75	0.01	0.13	0.06
Uppermost Arbuckle Play	Oil	1.10	17.70	6.60	0.11	1.77	0.70				5.91	0.06	1.05	0.39	0.01	0.10	0.04			
	Gas				7.00	124.10	45.80	0.06	1.08	0.40					0.41	7.33	2.70	0.00	0.06	0.02
Viola Oil and Gas Play	Oil	1.20	13.20	5.50	0.60	6.60	2.80				3.05	0.04	0.40	0.17	0.02	0.20	0.09			
	Gas				6.50	43.90	20.40	0.05	0.49	0.20					0.20	1.34	0.62	0.00	0.01	0.01
Total Undiscovered Conventional Resource		**31.30**	**552.40**	**267.40**	**509.84**	**10,205.45**	**5,974.70**	**10.76**	**209.81**	**123.60**		**3.34**	**58.49**	**29.57**	**37.13**	**704.52**	**415.80**	**0.82**	**15.07**	**8.91**

MMBO = Million Barrels of Oil
BCFG = Billion Cubic Feet of Gas

NGL = Natural Gas Liquids
MMBNGL = Million Barrels of Natural Gas Liquids
= Not Applicable

Wyoming State Office
Reservoir Mangement Group

[1] Potential resource is assumed to be evenly distributed across each play area or assessment unit.

Modified from Henry and Hester, 1995 for the Study Area

Table A1-6.

Data for U.S. Geological Survey 2002 assessment of undiscovered conventional assessment units in the Denver Basin Province, Cimarron and Comanche National Grasslands Study Area.

		Undiscovered Oil Accumulations				Undiscovered Gas Accumulations		
Assessment Unit Name	**Exploration Status**	**Number Range**	**Mean Size (MMBO)**	**Mean API Gravity (Degrees)**	**Drilling Depth Range (feet)**	**Number Range**	**Mean Size (BCFG)**	**Drilling Depth Range (feet)**
Dakota Group and D Sandstone	Established	5-60	0.9	35	1000-3000	1-10	6.0	1000-3000

MMBO= Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

(Higley et al., 2002)

Table A1-7.

U.S. Geological Survey 2002 estimated undiscovered technically recoverable resources for assessment units, Denver Basin Province, Cimarron and Comanche National Grasslands Study Area.

			Estimated Undiscovered Resource Quantities for 95 Percent, 5 Percent, and the Mean Case Probablilities of Occurrence for the Denver Basin Province										Estimated Undiscovered Resource Quantities for 95 Percent, 5 Percent, and the Mean Case Probabilities of Occurrence for the Study Area[1]								
			Oil (MMBO)			Gas (BCFG)			NGL (MMBNGL)				Oil (MMBO)			GAS (BCFG)			NGL (MMBNGL)		
Conventional Resource	Assessment Unit Name		95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	% of Assessment Unit Lying Within Study Area	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
	Dakota Group and D Sandstone	Oil	12.37	68.79	36.27	4.52	29.16	14.48	0.33	2.46	14.48	0.12	0.01	0.08	0.04	0.01	0.03	0.02	0.00	0.00	0.02
		Gas				9.66	61.64	30.95	0.58	4.29	2.04		0.00	0.00	0.00	0.01	0.07	0.04	0.00	0.01	0.00
	Total Undiscovered Conventional Resource		**12.37**	**68.79**	**36.27**	**14.18**	**90.80**	**45.43**	**0.91**	**6.75**	**16.52**		**0.01**	**0.08**	**0.04**	**0.02**	**0.11**	**0.05**	**0.00**	**0.01**	**0.02**

MMBO = Million Barrels of Oil

BCFG = Billion Cubic Feet of Gas

= Not Applicable or Not assessed

NGL = Natural Gas Liquids

MMBNGL = Million Barrels of Natural Gas Liquids

[1] Potential resource is assumed to be evenly distributed across each play area or assessment unit.

(Modified from Higley et al., 2002)