2.0 Proposed Action and Alternatives

This chapter defines the GNBPA boundaries, describes the existing and approved oil and gas facilities present within the GNBPA (Section 2.2), discusses standard development and production activities (Section 2.5), and describes the alternatives analyzed in this document. In developing the alternatives, the BLM followed guidance set forth in the BLM Instruction Memorandum ***(IM)*** No. 2005-247, Attachment 1, which provides recommendations on developing a range of reasonable alternatives for oil, gas, and geothermal development activities. Based on this guidance, the BLM developed the following alternatives for analysis in this EIS.

- **No Action Alternative:** This alternative assumes that approval of KMG's proposed project is denied and no new drilling would occur on Federal mineral estate except that currently permitted and approved under previous NEPA documents (Section 2.4).
- **Proposed Action Alternative:** This alternative consists of KMG's proposal to develop an additional 3,675 wells drilled from a maximum of 3,041 new well pads placed at up to 20-acre surface spacing within the GNBPA (Section 2.6).
- **Resource Protection Alternative:** This alternative consists of the same number of subsurface wells as the Proposed Action Alternative drilled from a reduced number of well pads (approximately 1,484) at 40-acre surface spacing to reduce the surface disturbance of the project (Section 2.7). Directional drilling would need to be used under this alternative to achieve the same number of subsurface wells (3,675) as the Proposed Action Alternative from a reduced number of surface well pads. The Resource Protection Alternative is the BLM preferred alternative.
- **Optimal Recovery Alternative:** This alternative maximizes the recovery of natural gas resources by increasing well surface spacing to 10 acres for an estimated 13,446 wells within the GNBPA (Section 2.8).

The No Action Alternative and each of the various action alternatives are discussed in terms of alternative-specific activities and schedule, alternative-specific design features, and surface disturbance summaries. Alternatives considered but eliminated from detailed analysis are discussed in Section 2.9. The analysis of each alternative in Chapter 4.0 focuses on the new disturbance that would occur under each alternative ***and would be in addition to existing and permitted disturbance***.

2.1 Greater Natural Buttes Project Area

KMG and other operators active in the GNBPA continue to implement approved oil and gas development including drilling new wells and constructing new infrastructure. Additionally, KMG proposes to drill new wells as infill to all productive formations, including but not limited to, the Green River Formation, Wasatch Formation, Mesaverde Group (including the Blackhawk Formation), Mancos Shale, and Dakota Sandstone. Target depths for the wells throughout this area would range from approximately 2,000 to 16,000 feet, with the primary focus on 2 formations: the Wasatch Formation where the wells would range from 2,400 to 6,500 feet deep and the Mesaverde Group where they would range from 3,900 to 11,000 feet deep. The total number of wells drilled and yearly drilling activity would depend largely on factors outside of KMG's control such as production success, engineering technology, reservoir characteristics, economic factors, commodity prices, rig availability, and lease stipulations.

The GNBPA consists of approximately 162,911 acres in an existing gas producing area located in T8S, R20-23E; T9S, R20-24E; T10S, R20-23E; and T11S, R21-22E in Uintah County, Utah. The lands included in the GNBPA are located in all or a portion of the townships illustrated in **Figure 1.1-2**.

The number of wellbores on any particular surface location or pad would vary according to KMG's success in deepening existing wellbores to the Mesaverde Formation as well as the ability to drill viable directional wellbores in environmentally constrained areas.

The project wells and facilities would be constructed and operated within the GNBPA on lands owned by the federal government, the State of Utah, private landowners, and lands held in trust for the benefit of the Ute Tribe. Tribal allottees are individual Native Americans who received land and sometimes mineral interests directly from the federal government. Lands with separate surface and mineral ownership, so called "split estate lands," comprise approximately 18 percent of land within the GNBPA. Surface ownership and ownership of oil and gas mineral rights are summarized in **Table 2.1-1**.

Table 2.1-1 Surface and Oil and Gas Minerals Ownership within the GNBPA

Surface Owner	Surface Acres	Percentage	Minerals Acres[1]	Percentage
BLM	88,565	54.4	117,116	71.9
Ute Indian Tribe	39,399	24.2	10,855	6.7
State of Utah	32,755	20.1	32,685	20.1
Private[2]	2,192	1.3	2,255	1.4
Totals	162,911	100	162,911	100

[1] Mineral ownerships reflect relative accuracy only.
[2] Includes allottees.

2.2 Existing Oil and Gas Infrastructure in the GNBPA

Based on UDOGM information (October 2007) for existing oil and gas infrastructure in the GNBPA, 1,562 vertical productive wells have been drilled on single well pads and are in operation. **Table 2.2-1** identifies those existing or approved oil and gas facilities that are present within the GNBPA.

Table 2.2-1 Existing Facilities

Facility	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Estimated Existing Surface Disturbance (acres)
Roads			
Access Roads[1]	391 mile	45 feet	2,130
Well Pads			
Single Existing Well Pads	1,562 each	2.5 acre	3,905
Construction/Production Facilities			
Mancamps	2 each	5 acre	10
Compressor Stations	23 each	16 acre	368
Chapita Process/Compression Plant	1 each	70 acre	70
Evaporation/Recycle Facilities	3 each	20 acre	60
Water Injection Facilities	5 each	3 acre	15
Facilities Subtotal			***523***

Table 2.2-1 Existing Facilities

Facility	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Estimated Existing Surface Disturbance (acres)
Linear Facilities			
Gas Gathering Pipelines (cross-country)	20 mile	20 feet	47
Gas Transport Pipelines (buried)	65 mile	75 feet	591
Water Pipelines (buried)	20 mile	75 feet	182
Electric Power Lines	32 mile	100 feet	388
Linear Facilities Subtotal			***1,208***
Total Existing Disturbance			***7,766***
Total Existing Disturbance as Percent of GNBPA			***4.8%***
Existing Surface Disturbance Interim Reclamation Estimates[2]			
Reclaimable Existing Surface Disturbance (acre)			3,267
Reclaimable Percent of Existing Surface Disturbance			42%
Reclaimable Existing Surface Disturbance as % of GNBPA			2.0%

[1] Assume access road length of 0.25 mile/well pad for existing wells.
[2] Interim reclamation estimates are based on the potential to reclaim (i.e., "reclaimable") 0.5 acre per existing well pad, 27 feet ROW for roads, and all Linear Facilities summarized in the table above.

2.3 Management Common to All Alternatives

Key documents and associated procedures that control oil and gas development and production on public, Tribal, state, and private lands are presented in **Table 2.3-1**. Following the completion of the NEPA compliance process, but prior to activities occurring on public or Tribal Lands, approvals for wells and ancillary facilities must be granted by the BLM and BIA as part of the requirements set forth by the Onshore Oil and Gas Order No. 1, “Approval of Operations on Onshore Federal and Indian Oil and Gas Leases,” issued under 43 CFR 3160. This process includes two procedural options for obtaining approval to drill a well. When operators decide to drill a well on BLM-administered lands, either a Notice of Staking (NOS) or an APD must be submitted to the BLM. A separate APD is submitted to UDOGM. No surface activity can be initiated on BLM-administered land until the well drilling application is approved by the BLM. Roads, pipelines, and other surface facilities constructed on BLM-administered lands, but outside of the lease or unit would require grant of a federal ROW from the BLM. Well facilities would require a federal bond. Tribal surface and mineral estate is administered in trust by the BIA. While the BLM would approve drilling permits on Tribal Lands, surface disturbance and ROWs would be approved by the BIA. All lands belonging to the State of Utah within the GNBPA are administered by the USITLA. Approval of APDs on state and privately owned lands would be subject to requirements of the UDOGM.

Table 2.3-1 Key Oil and Gas Development and Production Guidelines Applicable to all Alternatives

Activity	Governed by	Guidance Documents	Requirements
Approvals for Well Drilling, Completion, and Production	Federal	BLM Onshore Order #1 (43 CFR 3164.1; 48 ***FR*** 48916 and 48 ***FR*** 56226); 43 CFR 3162.5-1 Environmental Obligations. ***BLM IM UT 2010-55: Protection of Groundwater Associated with Oil and Gas Leasing, Exploration, and Development.*** BIA Approval of Operations (25 CFR 225.32).	• Preparation of an APD, including a surface use plan of operations and a drilling and completion plan. • Inspections prior to construction and drilling approval.

Table 2.3-1 Key Oil and Gas Development and Production Guidelines Applicable to all Alternatives

Activity	Governed by	Guidance Documents	Requirements
	State	UDOGM: Rule R649-3-4. Permitting of Wells to be Drilled, Deepened, or Plugged-Back; R649-3-18. On-site Predrill Evaluation.	
Access Road, Well Pad, and Utility Design and Construction	Federal State County	BLM "Surface Operating Standards for Oil and Gas Exploration and Development" (USDOI and U.S. Department of Agriculture [USDA] 2007); ROW acquisition (43 CFR 2800 *et al.)*. USEPA CAA Fugitive Dust Emission Standards (40 CFR 50), CWA Storm Water Discharges (40 CFR 122.26). USACE CWA Permitting of Dredge and Fill Operations (33 CFR 323). UDEQ Rule 307-205-7: Mining Activities Fugitive Dust Emissions Standards. UDOT Rule R933-3: Relocation or Modification of Existing Authorized Access Openings or Granting New Access Openings on Limited Access Highways. Uintah County General Plan, Chapter 7e: Roads and Transportation Planning (Uintah County 2005).	• Minimum standards for roads, well pads, and utilities. • Surface management BMPs. • Storm water discharge. • Dredge and fill operations. • Acquisition of federal ROWs. • Fugitive dust control requirements. • Requirements for encroachment onto State and County ROWs.
Drilling Operations	Federal State	BLM Onshore Order #2 (43 CFR 3164.1; 53 ***FR*** 46790) UDOGM: Rules R649-3-6 (Drilling Operations); R649-3-7 Well Control; R649-3-8 Casing Program; R649-3-9 Protection of Upper Productive Strata; R649-3-15 Pollution and Surface Damage Control; R649-3-14 Fire Hazards on the Surface; R614-2-4 Drilling Industry – Fuel Protection and Prevention; R68-9 Utah Noxious Weed Act.	• Well control methods. • Drilling reporting. • Well casing. • Groundwater protection methods. • Pollution control methods. • Fire prevention. • Noxious weed control.
Site Security	Federal	BLM Onshore Order #3 (54 ***FR*** 8056).	• Facility security requirements.
Measurement of Oil	Federal	BLM Onshore Order #4 (54 ***FR*** 8086).	• Measurement methods for produced oil.
Measurement of Gas	Federal	BLM Onshore Order #5 (54 ***FR*** 8100).	• Measurement methods for produced gas.
Disposal of Produced Water	Federal State	BLM Onshore Order #7 (58 ***FR*** 47354). UDOGM Rule R649-9 Waste Management and Disposal; UDOGM Rule R649-8 Reporting and Report Forms	• Criteria for the management and disposal of produced water. • Reporting and recordkeeping requirements.
Installation of Compression Facilities	Federal State	USEPA CAA (40 CFR 50 through 97) UDEQ Rule R210-1: Stationary Sources, R214-2: National Emissions Standards for Hazardous Air Pollutants, R401-4: Permitting New or Modified Stationary Sources.	• Minimum standards for air emissions. • Permit requirements and public notices.
UIC (Disposal of produced water)	Federal State	USEPA UIC (40 CFR 146.21 through 146.24). UDOGM Rule R649-5 UIC of Recovery Operations and Class II Injection Wells (R649-5-1 through R649-5-7, R693-2).	• Permit information requirements and public notices. • Well construction methods. • Testing and monitoring procedures. • Operational monitoring and reporting.
Well Abandonment and Reclamation	Federal State	BLM 43 CFR 3162.3-4 Well Abandonment. UDOGM Rule R649-3-24; and R6493-34 Well Site Restoration.	• Well plugging and abandonment. • Wellsite restoration process.

The objective of the on-site inspection is to review the proposed locations for wells and well pads, access roads, and ancillary facilities for consideration of the following: site-specific topography; topsoil/subsoil stockpiles; natural drainage and erosion control; vegetation and wildlife resources; historical and cultural resources; paleontological resources; and any other surface issues that may become apparent during inspection or are addressed in the lease stipulations.

The drilling application process also requires that an operator design individual well completions to protect fresh water aquifers. A BLM geologist and/or hydrologist performs an independent review of each APD utilizing Utah Geological Survey (UGS) and U.S. Geological Survey (USGS) geologic and hydrologic data and maps to generate a geologic report. The geologist and/or hydrologist identifies usable ground water and mineral-bearing zones that require protection, including Sole Source Aquifers (SSAs) and Drinking Water Source Protection Zones (DWSPZs). The petroleum engineer reviews the casing and cementing portions of the drilling plan to ensure adequate protection of those zones identified by the geologic report. The BLM further reviews the surface use plan to determine the adequacy of reserve pit design. COAs are attached to the APD as necessary.

Access roads and well pads located on federal public lands are designed and constructed under the guidelines contained in "Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development" (Gold Book) (USDOI and USDA 2007). Where possible, new roads, pipelines, and utility lines are located along existing linear ROWs in order to minimize additional surface disturbance. Construction of access roads, well pads, and other associated utilities is regulated under the CAA by the USEPA and UDEQ for fugitive dust emissions, and under the CWA by USEPA for storm water discharges and by the USACE for dredge and fill operations. UDOT Rule 307-205-7 and the Uintah County General Plan (Uintah County 2005), Chapter 7e requirements control encroachment on state and county ROWs.

Drilling and completion operations, including aquifer protection and pollution control methods, are outlined in the BLM Onshore Order No. 2 and the UDOGM Rules, which also include well spacing requirements. Operators are subject to various federal or state bonding requirements, depending on the SMA. Oil and gas production operations on federal lands are managed under Onshore Order No. 3, while Orders No. 4 and No. 5 address documentation of hydrocarbon production for taxes and royalties. The requirements for disposing of water produced during drilling and operations are addressed in Onshore Order No. 7. KMG has incorporated elements of the Onshore Orders and the BLM standard procedures into its standard operating practices for drilling and surface management.

Emissions standards associated with the installation of compression facilities, including upgrades to existing facilities and construction of new facilities, is regulated under the CAA by the USEPA and permitted through UDEQ on all lands within the GNBPA except on Tribal Lands where permitting is conducted through USEPA Region VIII.

The USEPA has promulgated rules for underground water injection that are applicable for wells located in the GNBPA. These rules address the allowable water pressures in the receiving formations, and the monitoring and reporting of these pressures. Monthly injection volumes and pressures are reported to the State of Utah or the USEPA, depending on jurisdiction. Well injection rates and pressures are measured daily through the use of surface monitoring devices at each injection well. In addition, well casing integrity tests must be completed at intervals as mandated by the State of Utah and the USEPA to ensure isolation of the injection interval.

Proposals for drilling and well testing are contained in a detailed drilling program included as a required portion of federal APD packages. Both the BLM and UDOGM prescribe procedures for well plugging and abandonment at the end of the life of a well, as well as site reclamation requirements and procedures.

2.4 No Action Alternative

Under the No Action Alternative, drilling and completion of development wells and infrastructure would continue as described in approved NEPA decision documents. A summary of surface disturbance associated with implementation of the No Action Alternative is presented in **Table 2.4-1**. This includes facilities disclosed through other NEPA documents or approved by other agencies but not yet constructed as of October 2007. This date was selected as a fixed point in time to represent information that is continuously changing. While the BLM recognizes there is a gap between this point in time and the publication date of this document, the information provides a consistent basis for evaluation of the project and alternatives.

The BLM recognizes that reclamation is difficult and is likely to require a long time to achieve in the Uinta Basin. Therefore, for purposes of analysis in this EIS, the total surface disturbance for the proposed project and alternatives without consideration of reclamation was used. The surface disturbance that would be reclaimed (i.e., reclaimable disturbance) is disclosed in the surface disturbance summary tables in recognition of the fact that the BLM would require the project proponents to reclaim unused disturbance during project operation. The disturbances listed in **Table 2.4-1** are ***in addition*** to the existing disturbance ***summarized in Table 2.2-1***.

Table 2.4-1 No Action Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Surface Disturbance (acres)
Roads			
Access Roads[1]	276 miles	45 feet	1,503
Well Pads			
New Single Well Pads	1,102 each	2.5 acres	2,755
Twinned Well Pads (Additional Disturbance)	0 each	0.2 acres	0
Multi-well Pads (Additional Disturbance)	0 each	0.2 acres	0
Well Pad Subtotal	***1,102 each***		***2,755***
Construction/Production Facilities			
Mancamps	0 each	5 acres	0
Compressor Stations	6 each	20 acres	120
Water Tank Batteries	8 each	3 acres	24
Water Injection Facilities (Additional Disturbance)	0 each	0.2 acre	0
Facilities Subtotal			***144***
Linear Facilities			
Gas Gathering Pipelines – Common ROW	262 miles	0 feet	0
Gas Gathering Pipelines – Cross-country	14 miles	20 feet	33
Gas Transport Pipelines (Buried)	0 mile	75 feet	0
Water Gathering Pipelines – Common ROW (Surface)	0 mile	0 feet	0
Water Connecting Pipelines (Buried)	26 miles	75 feet	236
Electric Power Lines	2.5 miles	100 feet	30
Linear Facilities Subtotal			***300***
No Action Alternative New Disturbance (acre)			***4,702***
GNBPA New Disturbance (%)			***2.9%***
Existing Surface Disturbance[2] (acre)			***7,766***
Total Surface Disturbance (acre)			***12,468***
Total GNBPA Disturbed (%)			***7.7%***

Table 2.4-1 No Action Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Surface Disturbance (acres)
Surface Disturbance Interim Reclamation Estimates[3]			
Reclaimable No Action New Surface Dist (acre)			1,753
Reclaimable Existing Surface Disturbance (acre)			3,267
Total Est. Reclaimable Surface Disturbance (acre)			5,020
Reclaimable Surface Disturbance (%)			40%
Reclaimable Surface Disturbance as % of GNBPA			3.1%

[1] Assume access road length of 0.25 mile/well pad.

[2] ***Existing disturbance is presented in Table 2.2-1.***

[3] Interim reclamation estimates are based on the potential to reclaim 0.5 acre per new well pad, 27 feet ROW for new access roads, and all new Linear Facilities summarized in the table above.

2.4.1 Field Development Plan and Schedule

Planned natural gas development in the GNBPA includes those facilities described in the NEPA documents for the following previously approved development projects:

- Bonanza EA;
- Love Unit EA;
- North Chapita EA;
- Rock House EA;
- West Bonanza EA;
- Chapita Wells-Stagecoach EIS; and
- Greater Deadman Bench EIS.

Based on the foregoing documents and a review of information from UDOGM, the BLM has estimated 1,102 wells remain to be drilled in addition to the 1,562 existing wells producing or shut in awaiting pipeline connection in the GNBPA (as of October 2007). **Figure 2.4-1** illustrates the distribution of the existing wells and conceptual locations of analyzed yet undrilled wells within the GNBPA as of October 2007. In addition to the 1,102 wells, supporting infrastructure also would be installed as disclosed in the above NEPA documents.

2.4.2 Alternative-specific Activities

Details regarding development activities specific to the No Action Alternative are described in the following subsections.

2.4.2.1 Access Roads

Access to 1,102 wellsites would require approximately 276 miles of access road. Based upon analysis of the existing road network in the area as of June 2006 (**Figure 2.4-2**), an average new access road length of 0.25 mile per well pad has been estimated.

2.4.2.2 Drilling and Completion of Vertical Wells

Implementation of the No Action Alternative would result in the drilling, completion, and construction of associated production facilities for an estimated 1,102 wells analyzed under previous NEPA actions. All of

the wells are assumed to be vertical wells drilled on individual well pads. At an estimated drilling rate of approximately 192 wells per year (current KMG rate), drilling activity in the GNBPA would continue for 5 to 6 years.

Approximately 2,270 acre-feet of water would be required to drill and complete the approved wells at an estimated 2.06 acre-feet per well, based on current water usage in the GNBPA.

2.4.2.3 Gas Production and Distribution

Approximately 276 miles of gas gathering pipeline would be installed on the surface to transport natural gas from wells to larger buried pipelines that connect to processing facilities. Approximately 262 miles (95 percent) of the natural gas gathering pipeline system would be placed in available access road ROWs. Any activity within or adjacent to a county road ROW would be done with the permission of and in coordination with the county. An additional 14 miles (5 percent) of the natural gas gathering system is expected to require cross-country routing outside of access road ROWs; cross-country routing would require a 20-foot ROW for construction.

Six compression and natural gas processing facilities would be constructed for a total additional 96,600 horsepower (hp) of compression. Approximately half of this additional compression would be gas fired and half would be electrically driven. Each site would require approximately 20 acres for the life of the facility.

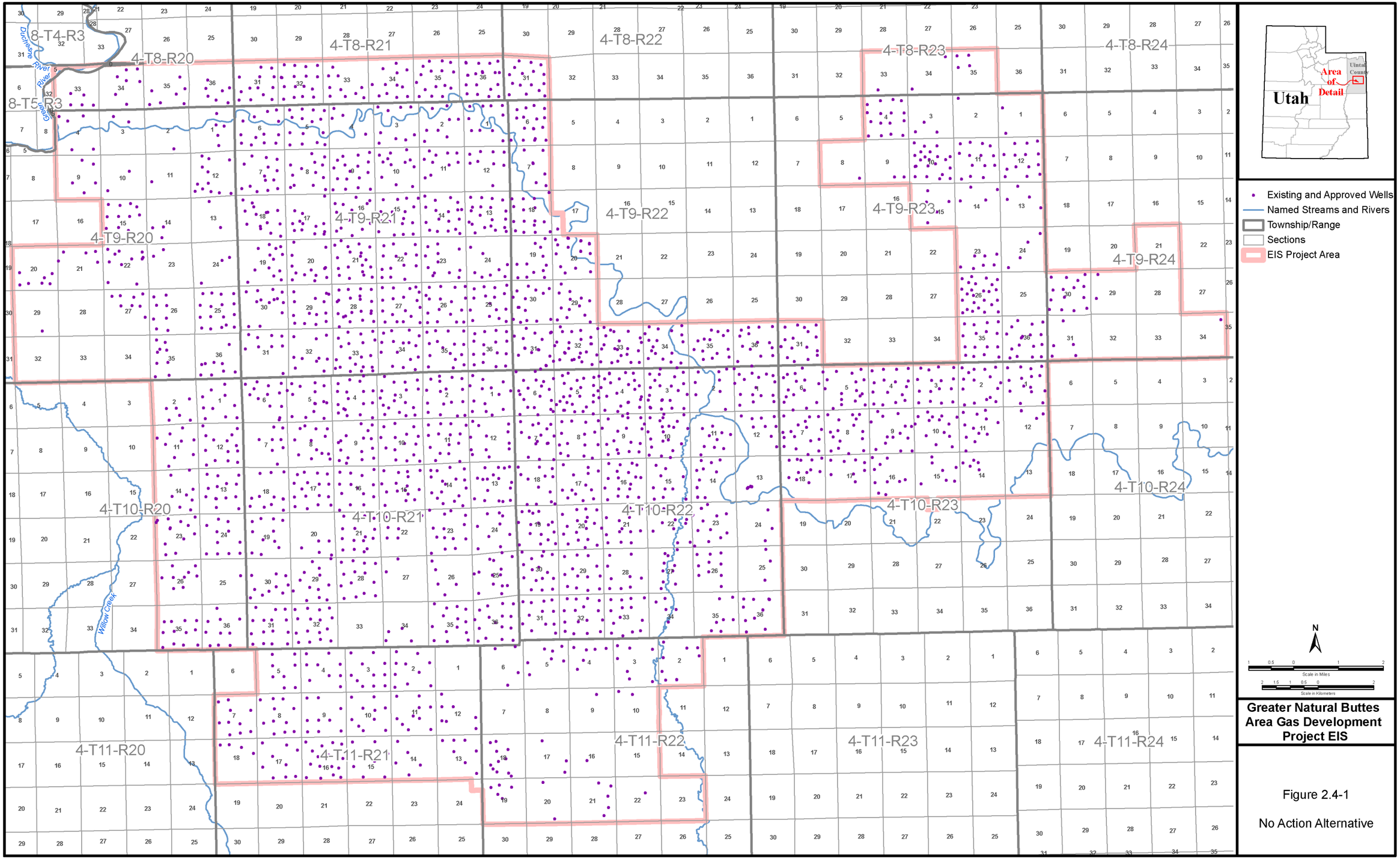
The No Action Alternative would include the installation of an additional 2.5 miles of overhead electric power lines to provide power to compression facilities and pumps at water disposal facilities. The power lines would be 35-kilovolt (kV) distribution lines originating from an existing 32-mile power grid. The power lines would be installed within a 100-foot-wide ROW.

2.4.2.4 Water Requirements

Under the No Action Alternative, fresh water used for well drilling and completion purposes would continue to be obtained from existing commercial water supply sources in or near the GNBPA. Withdrawals would be made from suppliers that hold existing groundwater or surface water rights permits through the Utah Division of Water Rights. Assuming that water recycling satisfies ***only*** half the demand, approximately 225 acre-feet per year ***of fresh water withdrawal*** would be needed ***for well drilling and completion***. ***Current plans are that this*** primarily would be withdrawn from ***shallow alluvial*** groundwater sources involving four ***commercial*** suppliers: Target Trucking (permit 43 -10***9***88), RN Industries (permits 49-164***5***, 49-2166, and 49-2231), Buggsey's Water Service (permit 49-2281), and Dalbo Water Services (probably involving permits 49-2235, 49-2229, and/or 49-1399) (Utah Division of Water Rights 2009). Source water for Buggsey's Water Service includes both a groundwater point of diversion and a surface point of diversion on the Green River near Ouray, Utah (Utah Division of Water Rights 2009). Any remaining fresh water demands***, such as those for dust suppression or domestic uses,*** would be met by Green River withdrawals near Jensen, Utah, under an existing permit (49-225) held by the Deseret Generation and Transmission Cooperative. ***These are estimated to be approximately 85 acre-feet per year.*** Any river withdrawals made through the cooperative likely would be small in total volume, and would be limited by the permitted maximum withdrawal rate of 15 cubic feet per second.

2.4.2.5 Produced Water Disposal

Eight water tank batteries at 3 acres each would be constructed for temporary storage of produced water. Approximately 26 miles of 4- to 12-inch, buried polypropylene pipe water flowlines would be installed within a 75-foot-wide ROW to transport produced water from new and existing storage facilities (tank batteries and existing evaporation ponds) to existing injection wells.

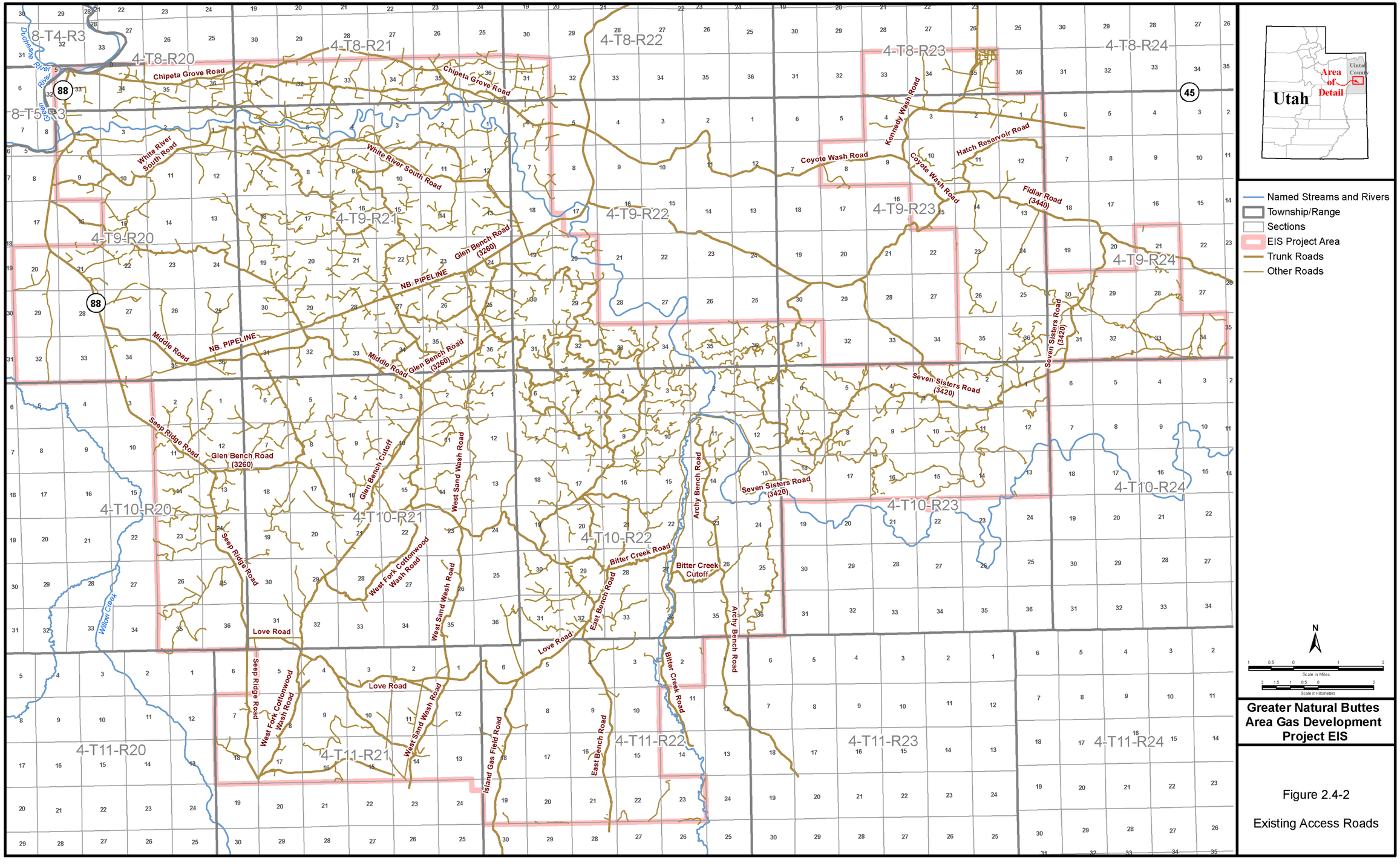


Greater Natural Buttes Area Gas Development Project EIS

Figure 2.4-1

No Action Alternative

Wednesday, March 12, 2008 9:48:14 AM
X:\0Projects\12100_013_Kerr_McGee_Greater_Natural_Buttes\APDEIS_Figures\Fig2_4-1_NoActionAlternative.mxd



Greater Natural Buttes Area Gas Development Project EIS

Figure 2.4-2

Existing Access Roads

Wednesday, March 12, 2008 9:48:50 AM
X:\0Projects\12100_013_Kerr_McGee_Greater_Natural_Buttes\APDEIS_Figures\Fig2_4-2_ExistingAccessRoads.mxd

Existing evaporation/recycle facilities would be used to allow produced water to evaporate or to be re-used in completion and drilling operations. Re-use of produced water during operations reduces the amount of water that would be obtained from other sources such as the White River or water wells. Re-use of produced water also would reduce the amount of residual waste water that would require re-injection or evaporation for disposal. Some of the produced water recycled from the ponds potentially would be used for hydraulic fracturing during completion operations, reducing the amount of water that would be injected or evaporated. Use of the existing evaporation ponds would reduce water trucking requirements within the GNBPA.

Transport of produced water to disposal facilities would require approximately 32,218 truck trips annually over an estimated average round trip transport distance of approximately 10 miles. This estimate assumes an average 100-barrel (bbl) capacity water truck and estimated annual produced water from the No Action Alternative wells of ***415*** acre-feet ***per year (8,820*** bbl of water per day [BWPD]). Existing disposal capacity includes ***approximately 353 acre-feet per year (***7,500 BWPD***)*** in evaporation ponds and ***approximately 856 acre-feet per year (***18,200 BWPD***)*** in active disposal wells, for a total capacity of ***approximately 1,209 acre-feet per year (***25,700 BWPD***)***. ***If total evaporative pond capacity is used, then approximately 353 acre-feet per year would be disposed in ponds and 62 acre-feet per year would be disposed by underground injection.***

2.5 Field Development Activities Common to All Action Alternatives

Project development within the GNBPA would result in the construction of new roads and use of existing roads. Equipment required by most wells would include a gas gathering pipeline, a separator, gas meter, produced water tanks, and liquid hydrocarbon storage tanks. Gas would be transported via pipeline to centralized compression and treatment facilities. Produced water would be transported by truck and/or pipeline to KMG-operated produced water disposal wells or to existing KMG or commercially owned evaporation ponds or disposal wells. To minimize new disturbance, KMG would utilize the existing ancillary facility infrastructure within the GNBPA, where possible, including gas compression facilities, power lines, water disposal and treatment facilities, and gas gathering pipelines.

The following sections summarize general pre-construction, construction, drilling and completion operations, production and maintenance operations, and abandonment and reclamation procedures common to all action alternatives. KMG has committed to AECPMs that would apply to project development unless the measures are superseded or modified by site-specific COAs. In general, KMG would:

- Comply with all applicable federal, state, county, and BLM regulations (including any applicable interagency memorandums of understanding ***[MOUs]***) for all operations associated with the project;
- Adhere to all lease stipulations and COAs; and
- Conduct its operations in accordance with the standards contained in its Surface Use Plan of Operations.

Key ACEPMs are provided in **Appendix A**. Detailed numbers and summaries of anticipated surface disturbance associated with each action alternative are presented within each action alternative section.

2.5.1 Pre-construction Activities

2.5.1.1 Surveying and Notice of Staking or Application for Permit to Drill

Prior to the start of construction activities on BLM-managed lands, KMG would:

- Submit site-specific applications (NOS/APD/Sundry Notice/ROW application);
- Survey and stake the location;

- Participate in an on-site inspection;
- Submit detailed construction plans, as needed; and
- Perform cultural resource, paleontological, biological (including threatened and endangered plant and animal species), and/or other surveys, as necessary.

For wells on BLM-managed land, KMG must obtain a permit from the BLM before surface disturbing activities can take place. To initiate the permitting process, KMG would file either a NOS or an APD with the BLM Vernal Field Office, which would process the application to ensure that it meets applicable requirements. For wells on split estate lands, KMG would follow the requirements of Section VI, Onshore Oil and Gas Order No. 1, for notifying and obtaining an access agreement with the surface owner.

A complete APD normally consists of a Surface Use Plan, Drilling Plan, evidence of bond coverage, and other information that may be required by the BLM in compliance with Onshore Oil and Gas Order No. 1. A Surface Use Plan contains information describing construction operations, access, water supply, well site layout, production facilities, waste disposal, and restoration/revegetation or reclamation associated with the site-specific well development proposal. The Drilling Plan typically includes information describing the technical drilling aspects of the specific proposal, safety specifications, and subsurface resource protection. Determination of the suitability of KMG's design, construction techniques, and procedures would be made by the SMA during the permitting process.

2.5.1.2 Pre-construction Activities and Construction Initiation

Prior to construction and APD approval, the SMA would conduct on-site inspections to assess potential impacts and recommend additional methods to mitigate impacts, if warranted and viable. The SMA may impose the mitigation measures as COAs to the APD. These additional environmental protection measures could address all aspects of oil and gas development, including construction, drilling, production, reclamation, and abandonment. The SMA would notify KMG of a date, time, and place to meet to perform an on-site inspection. Survey stakes would be used to indicate the orientation of the well pad and flagging would be used to indicate the routing of access roads, pipelines, or other linear features.

Changes or modifications would be made during the inspection if needed to avoid or mitigate impacts to natural and cultural resources. Cut and fill and construction issues also would be addressed, as necessary. For wells on BLM-managed land, provisions of 43 CFR 3101.1-2 and the BLM standard lease (Form 3100-11) allow for the relocation of the proposed well up to 200 meters and a delay in operations of up to 60 days. Requirements for local notices to leasees may include other protective measures.

2.5.2 Access Roads

Primary access to the GNBPA would be via Glen Bench Road, State Highway 45, and State Highway 88. Access within the GNBPA would be via the existing road network, which consists of arterial roads and individual well access roads. County roads within the GNBPA include Class 1-B gravel roads (Seven Sisters Road, Fidlar Road, Bitter Creek Road, and Seep Ridge Road) and a Class 1-B paved and graveled road (Glen Bench Road) (**Figure 2.4-2**).

New roads would be constructed where needed for vehicle access. Road design and construction specifications on BLM-managed lands would conform to Gold Book standards. Site-specific requirements would be incorporated on a case-by-case basis through COAs attached to the APD or ROW grant.

KMG has developed a conceptual Transportation Plan to support oil and gas development to be implemented by the Proposed Action (**Appendix C**). The exact location of well access roads would be determined at the time of the on-site inspection with the appropriate SMA. New roads would cross federal,

state, Tribal, and private surfaces. The plan includes measures to minimize resource conflicts and development costs. The plan objectives would:

- Maximize use of the existing road system;
- Facilitate identification of roads not needed for operations;
- Identify main arteries and if they are designed to a standard that would accommodate all weather and the volume of traffic anticipated;
- Minimize the number of loop roads;
- Minimize the crossing of side slopes greater than 40 percent;
- Minimize profile grades;
- Minimize drainage crossings, with emphasis placed on drainages with potentially large runoff flows and floodplains; and
- Design all roads to an appropriate level, no higher than necessary.

New roads would be built and maintained to provide year-round access, as necessary. Bulldozers, graders, and other types of heavy equipment would be used to construct and maintain the road system.

Existing roads that require upgrading would meet standards appropriate to the anticipated traffic flow and all weather road requirements. Upgrading may include ditching, drainage, graveling, crowning, and capping the roadbed as necessary to provide a well constructed, safe roadway. Construction or upgrading would not occur during muddy conditions. Where operations would involve the use of county roads or where a project road would connect to a county road, KMG would coordinate activities with the county road department.

Running surfaces of new roads are typically 18 feet wide. Access road disturbance has been calculated using a maximum disturbed width of 45 feet, which corresponds to a typical road ROW. The amount of surface disturbance resulting from road construction would depend upon the number of new well pads.

2.5.3 Drilling and Completion of Vertical Wells

2.5.3.1 Well Pad Construction

Well pads would be constructed to create a level surface for drilling equipment utilizing the native materials present at the site. Mineral materials from outside the GNBPA would not be required. Locations would be leveled by balancing cut and fill areas. Construction practices may include excavation or blasting to achieve a level pad. Blasting is normally required when bedrock is near the surface. Prior to blasting, the appropriate agency would be notified, and operations would be conducted according to applicable safety standards. Topsoil and native vegetation would be removed and separately stockpiled for use in the reclamation process.

The initial average well pad size for a single well would be approximately 2.5 acres, based on average dimensions of 310 by 350 feet. If productive, the reserve pit and all portions of the well pad not needed for routine operations would be reclaimed to reduce surface disturbance to an average of 2 acres for the life of a well. KMG would attempt interim reclamation of linear features, well pads, etc., but, due to the difficulty in achieving timely successful interim reclamation, this EIS assumes initial disturbance would be long-term disturbance. Locations for twin wells (i.e., a second vertical well drilled from the same pad to a deeper horizon) would increase disturbance by 0.5 acre for the additional well on a single pad. If the well were not productive, surface reclamation would commence upon notice of intent to abandon the last well on the pad.

2.5.3.2 Well Drilling

Drilling operations would be conducted in compliance with all applicable local rules and regulations including Federal Oil and Gas Onshore Orders and UDOGM rules and regulations. KMG anticipates that multiple drilling rigs would be operating in the GNBPA to achieve its production objectives. Each rig is expected to be able to drill an average of approximately 24 wells each year.

Following construction of the access road and well pad, a drilling rig would be transported to the wellsite and erected on the well pad. Wells would be drilled utilizing a conventional mobile drilling rig. The rig would be erected at the drill site after the conductor pipe has been set. Drilling operations typically would consist of drilling surface hole, "running" (inserting into the hole) and cementing in place the surface casing below all usable aquifers in the area, drilling a deeper and smaller diameter production hole, and running and cementing production casing. Intermediate casing, which would be used after setting surface casing and prior to drilling the production hole, also would be run when necessary. The rig would then be dismantled and demobilized from the location.

The quantity and composition of drilling fluids would be determined on a well-by-well basis. Drilling fluids typically consist of water or fresh water-based mud. Wells would utilize an open-loop circulation system with a reserve pit. Drilling fluids and cuttings would be contained entirely within the reserve pit. No hazardous substances would be placed in the reserve pit. Reserve pits would be constructed in accordance with applicable regulations and Gold Book specifications. The reserve pit would be constructed on the location and would not be located within natural drainages, where a flood hazard exists, or where surface runoff would destroy or damage the pit walls. If hydrocarbons enter a reserve pit, they would be removed as soon as possible in accordance with 43 CFR 3162.7-1. After drilling and completion operations are finished, the liquid contents of a reserve pit would be recycled for use in completing a subsequent well or removed and disposed of at an approved waste facility. Drill cuttings would be buried in the reserve pit. The reserve pit would be fenced on three sides during drilling operations and on the fourth side when the rig moves off the location. Fences would be constructed according to SMA requirements or as described in the Gold Book.

During drilling operations, a blow out preventer would be installed on the surface casing to provide protection against uncontrolled entry of reservoir fluids into the wellbore should reservoir pressures exceed the hydrostatic pressure of the wellbore fluid. In addition, a flow control manifold consisting of manual and hydraulically operated valves would be installed at ground level. All pressure control devices would comply with the provisions of Onshore Order No. 2.

Prior to setting casing, open hole well logs may be run to evaluate a well's production potential. If the evaluation concludes that sufficient oil and/or gas is present and recoverable, then steel production casing would be run and cemented in place in accordance with the well design, as specified in the approved APD and COAs. The casing and cementing program would be designed to isolate and protect shallower formations encountered in the wellbore and to prohibit pressure communication or fluid migration between zones. The cement would protect the well by preventing formation pressure from damaging the casing and retarding corrosion by minimizing contact between the casing and formation fluids. Certain cased-hole evaluation logs also may be run subsequent to setting and cementing production casing.

2.5.3.3 Well Completion

After a well is drilled and production casing is set, a completion unit would move on location to perforate and stimulate the reservoir. The casing would be perforated across the productive zones, followed by a stimulation treatment of the formation to enhance its transmissibility of oil and gas.

Hydraulic fracturing is a process intended to enhance the productivity of oil and gas wells. The method involves pumping fluids under high pressure into a target formation in order to create fractures. Once fractures are created, sand or artificial ceramic materials (proppant) are injected into the fractures to keep them open. The fracturing fluids are withdrawn and the proppant remains in

the fractures. The fracturing process essentially increases the size of the surface area to which hydrocarbons can flow, thereby increasing the productivity of the well.

The fracturing fluids can consist of complex mixtures of materials combined for the specific conditions encountered in a specific oil or gas field. Specific conditions may include, but are not limited to: the characteristics of the reservoir rocks, the depth (and therefore pressure and temperature), the nature of the formation fluids, the ease of mixing the fluids at the well site, and the stability and consistency throughout the treatment process (Miskimins 2010). While specific fracturing ingredients may vary, they generally consist of water, proppant, and lesser amounts of other materials that are used to accomplish certain objectives and to provide for successful well stimulation or recovery of fracturing fluids.

The mixtures may vary within a given production field depending on fracturing job designs of individual operators and the service companies engaged to conduct the work. Nelson and Hoffman (2009) reviewed the completions for 34 wells in the Uinta Basin and found that well stimulation treatments for the Wasatch Formation consisted of median values of 3,000 gallons of acid, 75,000 gallons of water, and 150,000 pounds of sand. According to the UDOGM database, in a well completed by KMG in January 2010 (the NBU 1021-13H4CS, located in Section 13, T10S, R21E), the fracturing job consisted of 62,400 gallons of water and 59,000 pounds of sand used to treat the Wasatch zone and 259,000 gallons of water and 216,000 pounds of sand used to treat the Mesaverde zone. It would be expected that fracturing treatments at GNBPA would be similar to the examples cited above, but may vary by specific formation, production interval, and well construction conditions.

2.5.3.4 Water Requirements

Water would be used during drilling and completion operations and for dust abatement on access roads, as needed. Produced water, oil, and other byproducts would not be applied to roads or well pads for control of dust or weeds.

An average of approximately 16,000 bbls (2.06 acre-feet) of water would be utilized during drilling and completion operations for each well. KMG has begun to recycle produced water in the field to be used for new well completions. If this operating practice proves successful, the fresh water requirements for well completions would be reduced. ***However, it is not possible to estimate the volumes of recycled fracturing water for the entire GNBPA. Water recycling has been successful in some areas in the field, but the amount of water that can be recycled is highly dependent on site-specific conditions and is more easily accomplished when recycled fracturing flow back fluids can be re-used for multiple wells located on the same pad or can be easily transported to other pads by temporary pipelines.***

Fresh water used for drilling and completion purposes would be obtained from commercial water supply sources. These sources would consist of both groundwater from wells and surface withdrawals from the Green River. Withdrawals would be made ***by*** suppliers that hold existing water rights permits through the Utah Division of Water Rights.

Groundwater ***from shallow alluvial wells*** would be obtained from Target Trucking (permit 43-10***9***88), RN Industries ("RNI Water Plant"; permits 49-1645, 49-2166, and 49-2231), Buggsey's Water Service (permit 49-2281), and Dalbo Water Services (probably permits 49-2235, 49-2229 and/or 49-1399). Source water for Buggsey's Water Service includes both an underground point of diversion (a well) and a surface point of diversion (the Green River near Ouray, Utah) (Utah Division of Water Rights 2009). Based on estimates from KMG and additional estimates of the supply available from Dalbo Water Services wells, approximately 225 acre-feet per year would be obtained from these four sources combined. All of these points of diversion are located in Ouray, Utah, or the general vicinity ***and are supplied from shallow alluvial wells near the Green River or White River***.

Estimates of water supply requirements vary between the action alternatives. As needed, all remaining fresh water would be obtained through the Deseret Generation and Transmission Cooperative. That organization holds rights to surface withdrawals from the Green River approximately 3 miles south of Jensen, Utah (permit 49-225) (Utah Division of Water Rights 2009).

2.5.3.5 Ancillary Facilities

Mancamps to house rig crews near the working rigs likely would be required in addition to those existing in the GNBPA. Each mancamp would accommodate a single rig crew. KMG would locate one mancamp on federal land (Section 3, T10S, R21E) and a second mancamp on state land. Each mancamp would require approximately 5 acres and would be reclaimed when no longer needed.

2.5.3.6 Equipment and Manpower Requirements

Four to six men would comprise the construction crew for each access road and well pad. They would access the location using an average of three light trucks. Two to three pieces of heavy equipment, such as bulldozers and motor graders, would be used to perform the earth-moving operations. Both the access road and well pad typically can be constructed within 7 to 14 days.

An average of 10 persons would be required for drilling and completion operations, although the actual number would range from approximately 5 to 50 people. An average of eight vehicles would be used for access to each location daily.

Duration of drilling operations on a given well can vary depending on depth and conditions encountered while drilling, but duration on location in the GNBPA can range from approximately 8 to 50 days. Completion operations typically require approximately 7 days per formation completed.

2.5.4 Gas Production, Distribution, and Maintenance

2.5.4.1 Wellsite Facilities

Well production facilities would include the well head, valves, piping, and a combination separator/gas meter that would be housed in a small building on each location. Each well pad in the Natural Buttes or Love units within the GNBPA would contain a single 300-bbl combination tank to contain produced water and condensate. Outside of the federal units but within the GNBPA, each location would contain two 300-bbl tanks, one each for produced water and liquid hydrocarbons. In addition, one or more 500-gallon (or smaller) chemical tanks containing scale/corrosion inhibitor, methanol, or soap and a plunger lift would be located on all wellsites.

2.5.4.2 Gas Pipelines

Steel gathering pipelines with a 3, 4, 6, 8, or 10-inch outside diameter would be installed on the ground surface to transport the produced gas from the wells to the larger (more than 10 inches) lateral pipelines. Burying pipelines throughout much of the GNBPA can be challenging due to the presence of shallow bedrock and difficult reclamation conditions related to shallow, saline soils. However, KMG continuously evaluates the practicality of burying natural gas pipelines on a case-by-case basis and has found that it generally is practical to bury lateral lines when collecting gas from four wells or more on a multi-well pad. For purposes of this EIS analysis, it is assumed that KMG would not bury natural gas gathering pipelines that are 10 inches or less in diameter. KMG would utilize existing ROWs and road disturbances as much as possible when burying new pipelines. ***The BLM would decide on a site-specific basis when burial of gas pipelines is not appropriate; for example, the BLM recognizes that in cases where slickrock or other large rock is exposed at the surface or within 3 feet of the surface, burial may not be practical.***

The applicant has committed to burying new pipelines within 100-year floodplains (**Appendix A**). In addition, pipeline crossings of streams would conform to the *Hydraulic Considerations for Pipelines Crossing Stream Channels* as outlined in the BLM Vernal RMP (BLM 2008b). Pipeline segments would be welded or

zaplocked together on disturbed areas in or near the location, whenever possible, and dragged into place. New gathering pipelines would be installed parallel to and within approximately 10 feet of access road running surfaces unless precluded by topography, by county prohibition where installed adjacent to county-maintained roads, or by gathering system constraints. Surface gathering lines would be buried where they intersect with access roads. The exact location of pipelines would be determined at the time of the on-site inspection with the appropriate SMA. Ramps across the surface lines would be used where necessary to allow the periodic crossing of surface gathering lines.

The 27-foot portion of access road ROWs outside the 18-foot road running surface would be used for routing surface natural gas gathering pipelines. The surface area within a road ROW but outside of a road's running surface would be re-vegetated after gathering line construction is complete, although reclamation is recognized to be difficult in the arid environment of the GNBPA. In addition, some cross-country routing of surface gathering pipeline may be required that would result in disturbance to a 20-foot-wide pipeline ROW. All areas within those cross-country ROWs would be re-vegetated after gathering line construction.

Drilling the proposed wells may require the installation of larger buried pipelines to transport natural gas to processing facilities. Construction of larger-diameter (larger than 10 inches) natural gas pipelines would require temporary use of a 75-foot-wide construction corridor. The larger buried pipelines would be located within existing pipeline ROWs or routed adjacent to roads as much as possible. Where practical, the 75-foot width would include the actual road surface. Pipe segments would be welded into longer sections adjacent to a trench and buried. Construction and installation of a buried pipeline would result in additional surface disturbance. After the pipe is buried, the construction corridor and ROW would be reclaimed.

2.5.4.3 Gas Compression and Processing

Natural gas would be transported to existing facilities for compression, treatment, processing, and sales gas compression. New gas-powered compressors would be muffled and housed to decrease the audible noise level. Gas would be transported from the wellhead via gathering pipelines to field compressor stations, where the gas would be compressed, to the Chapita central processing plant in Section 15, T9S, R22E, then further compressed for delivery to interstate pipelines operated by Questar, Northwest Pipeline, Wyoming Interstate Company, Colorado Interstate Gas, or others.

KMG would install only low emission dehydrators at existing and future compressor stations to eliminate hazardous air pollutants (HAPs) that may otherwise result. Additional dehydration is performed at the existing processing facilities, including the Chapita Plant, Bridge Station, Ouray, and Cottonwood. KMG also would install control devices and implement procedures to reduce emission of air pollutants during drilling, completion, production, and transportation activities.

2.5.4.4 Electrical Power Requirements

Additional overhead electric power lines may be installed to serve produced water disposal wells and proposed compression. Either natural gas-driven generators or natural gas engines would be used initially to supply power to the injection pumps at the proposed produced water disposal wells. Overhead electric lines may be subsequently installed where practical to provide power to the pumps, replacing the natural gas powered compressor engines. KMG anticipates an approximately 50/50 split between electric powered and natural gas powered compressor engines.

2.5.4.5 Normal Maintenance

New wells would typically be visited daily for 2 to 3 weeks after completion, depending upon well performance. During this time, the new well would be visited once by a "pumper" (oilfield maintenance worker) and by 3 to 4 water trucks daily. Visits to each well would be reduced to approximately three times a week by one pumper and one water truck daily for the life of a well. After initial completion, wellsite telemetry would be installed to reduce the number of trips to a well by a pumper; however, this reduction was not quantified for the analysis in this EIS. Surface pipelines would be visually inspected on a regular basis.

Maintenance of non-county roads within the GNBPA during drilling and construction would be the responsibility of KMG and other operators, as appropriate, and would be performed consistent with SMA specifications. During the duration of the project, KMG/operators would monitor the project roads and perform appropriate repairs. Repairs may be necessary to correct excessive soil movement, rutting, and/or damage to cattleguards, gates, or fences.

2.5.4.6 Workovers

Periodically, a workover on a well may be required. A workover uses a unit similar to a completion rig to perform a variety of maintenance procedures and keep the well operating as efficiently as possible. Workovers can include repairs to the wellbore equipment (casing, tubing, etc.), the well head, or the producing formation itself. These repairs generally occur during daylight hours and are typically of short duration. The typical workover would require approximately 3 days; however, workover operations can range from 1 to 10 days, with a small number requiring more than 10 days. Workover operations may require 4 to 30 men, with average manpower requirements of 6 persons. The frequency for this type of work cannot be accurately projected since workovers vary well by well and depend on site-specific circumstances. No additional surface disturbance would result from workover operations, and no regulatory approvals ***are required***.

2.5.5 Produced Water Disposal

Produced water may be confined to a lined pit for a period not to exceed 90 days after initial production, weather permitting. After the 90-day period, the produced water would be contained on the well pad in a tank prior to being transported by water hauling trucks or gathering pipelines to disposal facilities. Produced water would be disposed of via subsurface injection, into commercial produced water disposal ponds, into existing KMG-owned evaporation ponds, or would be used in subsequent completion and additional drilling operations. Water not evaporated in a particular pond or used for fracturing would be pumped via pipeline to either a disposal well for injection or to one of the other ponds.

2.5.5.1 Water Disposal Wells and Injection Facilities

Additional produced water disposal wells would likely be drilled in the GNBPA on existing well pads, or existing wellbores would be converted from natural gas production to disposal operations to minimize additional surface disturbance. The number of produced water disposal wells would depend upon the ability to obtain the necessary permits through the appropriate permitting authority and the number of additional wells drilled under a given alternative. Injection into disposal wells is KMG's preferred method of produced water disposal. The Birds Nest aquifer, a unit in the Parachute Creek Member of the Green River Formation, would be the primary subsurface zone for injection of produced water.

Injection disposal of produced water is a highly regulated activity. Underground injection wells used in conjunction with oil and gas production are referred to as Class II wells under the UIC program (**Table 2.3-1**). Class II wells can be used either for pressure maintenance to increase the efficiency of the recovery of oil and gas, or can be used for the disposal of liquid waste generated by oil and gas production operations that meets the definition of exploration and production waste exempt under the Resource Conservation and Recovery Act, Subpart D (mainly produced water).

Permitting of Class II wells is regulated in Utah by the USEPA and the State of Utah. On statutorily defined "Indian Country" lands (18 USC 1151), the USEPA is the authorizing regulatory agency and the UDOGM regulates the UIC program on lands not designated as "Indian Country." In the GNBPA, the USEPA regulates the UIC program. The permit process requires agency review of the application and a 30-day public comment period upon publication of notice of a draft permit. If there are no protests or objections to a pending application, it will be approved administratively.

The Birds Nest aquifer has unusually high porosity and permeability because of the dissolution of nahcolite and other easily soluble minerals. The high porosity and permeability are the attributes

that help make the aquifer a good injection disposal zone, but these attributes can cause a drilling phenomenon called "lost circulation" in which drilling fluids leak from the borehole into the formation. Present practice in the Uinta Basin is to use air rotary drilling rigs to drill the shallower sections of the gas wells through the Birds Nest aquifer and to depths below the high-grade oil shale zones. Air rotary drilling rigs also are used to drill disposal wells to total depth to alleviate the lost circulation problems. For disposal wells in the Birds Nest aquifer, casing is required to be cemented from the bottom of the upper confining zone (above the injection zone) to the surface. This cement must be determined to have adequate bond between the casing, cement, and borehole wall to ensure that fluid does not move out of the zone and endanger USDWs. If a cement bond log indicates there is inadequate bond, then the applicant is required to demonstrate Part II Mechanical Integrity and/or conduct remedial actions. After any remedial actions, the cement must again be tested for adequacy. This type of testing is typically through temperature logging and radioactive test surveys. Once the cement is determined to be adequate, then the hole would be deepened to the top of the lower confining zone and the injection zone would be completed as open-hole (no casing). The USEPA reviews the well construction proposed during the UIC permitting process. The final detailed completion procedures are submitted to USEPA after the well is drilled, cased, cemented, and logged.

Once produced water injection commences, the operator must conduct tests or surveys and provide the agency with the results as required under the UIC program. The tests and data required include a step-rate test, a mechanical integrity test, a radioactive tracer survey, a temperature test on the injection well, and temperature surveys on nearby wells to document that injection wells meet construction requirements, which prevent migration of fluids into underground sources of drinking water ***(USDWs)***. The regulating agency may require additional monitoring if necessary. ***There currently are seven salt water disposal wells condensed into a general location with potential of more in the future. This location is predicted to be in close proximity to where the Birds Nest aquifer becomes a USDW. KMG and USEPA UIC program have collaborated on the design of the Birds Nest Aquifer Monitoring Plan. This Monitoring Plan is in the process of being finalized. The purpose of the Birds Nest Aquifer Monitoring Plan is to horizontally track the produced water and determine when it reaches the monitoring wells. Through water analysis, these monitoring wells are better defining the area where the Birds Nest aquifer is not a USDW. The KMG cluster injection wells are close to what has been coined the "compliance zone" or the area where the Birds Nest aquifer transitions into a USDW. The major points of the plan include the following:***

- ***Five existing production wells have been converted to monitor wells. Three of the wells are up dip (south of the injection wells) and two of the wells are down dip (north of the injection wells).***
- ***Water samples for chemical analysis will be collected during initial monitor well completions and on an annual basis. The sulfate ion concentration in initial and annually sampled water from the monitor wells will be used to differentiate injection water (>800 milligrams per Liter [mg/L]) from the natural Birds Nest aquifer formation water (<50 mg/L) in this area.***
- ***Static fluid levels by tapeline water level meter will be measured initially and quarterly in each monitor well to evaluate potential pressure influences from the injection wells.***
- ***Bottom hole temperature will be measured at the mid-perforation depth initially and annually within each monitor well to help determine when the produced water front reaches the area.***
- ***Water samples will be collected and analyzed initially and annually from each monitor well to document any potential changes in water chemistry caused by the injection wells.***
- ***The compliance boundary will be defined based on stabilized, isolated, and representative Birds Nest aquifer water samples collected during the completion of all disposal wells, the completion of the five monitor wells, and the plugging and abandonment operations of inactive producing wells located in the immediate area.***

- ***The operator (or its successor companies) will be responsible for plugging and abandonment of all monitor wells once they are no longer required.***
- ***The monitor wells will remain bonded as oil and gas wells.***

The monitoring plan will be included in all new Birds Nest UIC permits and appended to existing approved Birds Nest UIC permits in Sections 33, 34, and 35, T9S, R21E, Uintah County, Utah.

2.5.5.2 Water Pipeline System

KMG would install 4- to 12-inch buried pipelines to interconnect all water management facilities including salt water disposal wells, evaporation/recycle ponds, and centralized tank batteries. These water pipelines would be buried to prevent freezing. These pipelines would facilitate water transport among the individual disposal sites during maintenance on either a disposal well or evaporation/recycle pond, providing a countermeasure and response mechanism if problems occur elsewhere in the water management system. The buried water pipelines would be located adjacent to existing roads or within existing buried pipeline corridors, where possible. Construction would require a 75-foot construction ROW, which would be reclaimed as near as practical after pipeline installation as described in Section 2.5.7, Reclamation and Abandonment.

Water gathering pipelines (between wells and disposal systems) would be considered to reduce traffic impacts from water trucking to disposal facilities. Three- to 6-inch steel and/or polypropylene pipeline could be installed in conjunction with (along side) the gas gathering pipelines. Surface installation within the 45-foot construction width of the access road would result in no additional surface disturbance. KMG continuously evaluates the technical and economic viability of water gathering pipelines versus trucking. In general, KMG currently transports produced water by truck from areas that are remote from the centralized water collection system. On a case-by-case basis, KMG evaluates the economic feasibility of connecting remote areas to the centralized water collection system with pipelines and has connected several of these remote areas to the system. However, analysis for the EIS has assumed that all water transport between wells and disposal systems would be by truck.

2.5.6 Hazardous Materials and Solid Waste

A variety of chemicals, including lubricants, paints, and additives are used to drill, complete, and operate a well. Some of these substances may contain constituents that are hazardous. Hazardous materials can include some greases or lubricants, solvents, acids, paint, and herbicides, among others. These materials would not be stored at well locations although they may be kept in limited quantities on drilling sites and at production facilities for short periods of time. Transportation of the materials to the well location is regulated by the USDOT under 49 CFR, Parts 171–180. USDOT regulations pertain to the packing, container handling, labeling, vehicle placarding, and other safety aspects.

None of the chemicals that would be used during drilling, completion, or production operations meet the criteria for being an acutely hazardous material/substance or meet the quantities criteria per the BLM IM No**.** 93-344. ***KMG would comply with the Superfund Amendments and Reauthorization Act (SARA) Title III reporting requirements for materials used in quantities greater than 10,000 pounds during drilling and completion operations. For example, cement used to isolate the steel casing from the surrounding wellbore is a reportable SARA Title III material.*** In addition, extremely hazardous substances, as defined in 40 CFR 355, in threshold planning quantities, would not be used, produced, stored, transported, or disposed of while drilling or completing a well.

Because of increasing concerns about the constituents and chemicals used in hydraulic fracturing, KMG will begin disclosing the contents of hydraulic fracture jobs on a well-by-well basis. This information will be provided in a registry developed jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. The registry will be searchable by the public and will include general well information, water volumes, and chemical information consistent with

material safety data sheets including the ingredient percentage in both the additive and hydraulic fracturing fluid. The registry will be utilized in states such as Utah that do not have well-by-well disclosure regulations. As states continue regulatory development, the registry will be phased out, although historic information will remain accessible. The registry is being developed as a voluntary effort to provide key information to the public in a timely fashion while a more substantial effort is pursued. That longer term endeavor is expected to produce a solution that links into the electronic data management system in each state and allows the public convenient and consistent access to the hydraulic fracturing information as well as drilling and completion information required to be reported by each state.

Most wastes that would be generated at project ***facilities*** are excluded from regulation by the Resource Conservation and Recovery Act under the exploration and production exemption in Subtitle C (40 CFR 261.4[b][5]) and are considered to be solid wastes. These wastes include those generated at the wellhead, through the production stream, and through the gas plant. Exempt wastes include produced water, production fluids such as drilling mud or well stimulation flowback, and contaminated soils.

Any release of oil, gas, salt water, or other such fluids would be immediately cleaned up and removed to an approved disposal site. The spills would be reported to the AO and other appropriate authorities. KMG would develop and maintain site-specific Spill Prevention Control and Countermeasures Plans (SPCC P***lan***s) for each facility in the GNBPA ***subject to USEPA's oil spill prevention program under 40 CFR Part 112 (USEPA 2010a)***. An example site-specific SPCC P***lan*** is provided in **Appendix D**. To satisfy SPCCP requirements, if storage facilities or tanks are constructed, they would be constructed in accordance with applicable regulations.

A facility would be subject to 40 CFR Part 112 if it had an aggregate aboveground oil storage capacity greater than 1,320 U.S. gallons or a completely buried storage capacity greater than 42,000 U.S. gallons, and if there were a reasonable expectation of an oil discharge into or upon navigable waters of the U.S. or adjoining shorelines. Oil of any type and in any form would be covered, including but not limited to petroleum, fuel oil, sludge, oil refuse, and other oils of plant and animal origin.

A facility that meets the criteria would comply with the SPCC rule by preventing oil spills and developing and implementing an SPCC Plan. For spill prevention, actions that a facility owner/operator can take to prevent oil spills include the following:

- ***Using containers suitable for the oil stored.***
- ***Providing overfill prevention for oil storage containers.***
- ***Providing sized secondary containment for bulk storage containers. The containment needs to hold the full capacity of the container plus possible rainfall.***
- ***Providing general secondary containment to catch the most likely oil spill when transferring oil to and from containers and for mobile refuelers and tanker trucks.***
- ***Periodically inspecting and testing pipes and containers. Inspections must be documented.***

The owner or operator of the facility must develop and implement an SPCC Plan that describes oil handling operations; spill prevention practices; discharge or drainage controls; and the personnel, equipment, and resources at the facility that are used to prevent oil spills from reaching navigable waters or adjoining shorelines. Although each SPCC Plan is unique to the facility, there are certain elements that must be described in every plan, including:

- ***Define the operating procedures at the facility to prevent oil spills.***

- ***Identify and describe control measures (such as secondary containment) installed to prevent oil spills from entering navigable waters or adjoining shorelines.***
- ***List countermeasures to contain, cleanup, and mitigate the effects of an oil spill that has impacted navigable waters or adjoining shorelines.***

Trash containers and portable toilets would be located on construction sites. Garbage, trash, and other waste materials would be collected in portable, self-contained, fully enclosed trash cages during construction, drilling, and completion operations and disposed of at an approved landfill. Trash would not be burned on location. Construction locations and wellsites would be cleaned of other debris and waste materials and removed from the location after drilling and completion operations.

2.5.7 Reclamation and Abandonment

Reclamation of surface disturbance associated with the proposed project and alternatives would be implemented in accordance with the ***BLM*** Green River District Reclamation Guidelines (BLM 2009a) ***provided in Appendix E***. The guidelines would apply to reclamation activities in the GNBPA and include measurable standards as well as the monitoring and reporting of compliance with the reclamation standards. KMG's draft Reclamation Plan ***also is provided in*** **Appendix E** ***and*** generally is consistent with the ***BLM*** Green River District Reclamation Guidelines***. KMG's draft Reclamation Plan*** would be revised and finalized to develop a site-specific plan for each component of the project for which an APD and/or ROW application is submitted to the BLM.

Surface disturbance associated with electric power line, surface pipeline, and buried pipeline installation would be reclaimed as soon as ***practicable and weather permitting*** according to the Reclamation Plan (**Appendix E**). Interim reclamation of the well pad would be performed as soon as practicable in accordance with applicable COAs after a well is drilled, completed, and put on production. Before reclamation begins on the reserve pit, it would be allowed to dry. After liquid removal, pits would be closed in accordance with surface management agency guidelines. The liner would be buried to a minimum of 4 feet below the surface. The pit and that portion of the location not needed for production operations would be reclaimed in accordance with applicable state regulations and Gold Book procedures. KMG would reseed the disturbed areas with mixtures specified by the applicable SMA or surface owner. Follow-up survey and treatment of weeds and invasive species would be conducted until reclamation is deemed to be successful and/or complete.

Abandoned wellsites, roads, and other disturbed areas would be restored as near as practical to their original condition and in compliance with applicable federal, state, and Tribal regulations as well as the COAs. At the time of final abandonment, all surface equipment, including surface gathering pipelines, would be removed from the site. Cut and fill materials would be recontoured and topsoil would be replaced on the surface above the former location to blend the site with its natural surroundings. All surface disturbance would then be planted with a seed mixture of grass and plant species as specified by the appropriate SMA. Follow-up survey and treatment of weeds and invasive plant species would be conducted until reclamation is deemed to be successful and/or complete.

At final abandonment of wells on BLM-managed lands, the casing would be cut off at the base of the cellar or 3 feet below the final restored ground level, whichever is deeper. KMG would cap the casing with a metal plate a minimum of 0.25 inch thick. The cap would be welded in place, and the well location and identity would be permanently inscribed on the cap. The cap would be constructed with a weep hole.

2.6 Proposed Action Alternative

A summary of surface disturbance associated with implementation of the Proposed Action Alternative is presented in **Table 2.6-1**. The disturbance indicated in **Table 2.6-1** is new disturbance that would occur in addition to ***existing disturbance (Section 2.2) and new disturbance under*** the No Action Alternative discussed in Section 2.4, No Action Alternative.

Table 2.6-1 Proposed Action Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Surface Disturbance (acres)
Roads			
Access Roads[1]	760 miles	45 feet	4,147
Well Pads			
New Single Well Pads	3,041 each	2.5 acres	7,603
Twinned Well Pads (Additional Disturbance)	634 each	0.2 acre	127
Multi-well Pads (Additional Disturbance)	0 each	0.2 acre	0
Well Pad Subtotal	***3,675 each***		***7,729***
Construction/Production Facilities			
Mancamps	2 each	5 acres	10
Compressor Stations	2 each	20 acres	40
Water Tank Batteries	2 each	3 acres	6
Water Injection Facilities (Additional Disturbance)	15 each	0.2 acre	3
Facilities Subtotal			***59***
Linear Facilities			
Gas Gathering Pipelines - Common ROW	722 miles	0 feet	0
Gas Gathering Pipelines - Cross-country	38 miles	20 feet	92
Gas Transport Pipelines (Buried)	35 miles	75 feet	318
Water Gathering Pipelines – Common ROW (Surface)	587 miles	0 feet	0
Water Connecting Pipelines (Buried)	25 miles	75 feet	227
Electric Power Lines	7 miles	100 feet	85
Linear Facilities Subtotal			***722***
Proposed Action New Disturbance (acre)			***12,658***
GNBPA New Disturbance (%)			***7.8%***
No Action Alternative New Disturbance[2] (acre)			***4,702***
Existing Surface Disturbance[3] (acre)			***7,766***
Total Surface Disturbance (acre)			***25,125***
Total GNBPA Disturbed (%)			***15.4%***
Surface Disturbance Interim Reclamation Estimates[4]			
Reclaimable New Surface Disturbance (acre)			4,731
Reclaimable No Action New Surface Dist (acre)			1,753
Reclaimable Existing Surface Disturbance (acre)			3,267
Total Est. Reclaimable Surface Disturbance (acre)			9,751
Reclaimable Surface Disturbance (%)			39%
Reclaimable Surface Disturbance as % of GNBPA			6.0%

[1] Assume access road length of 0.25 mile/well pad.

[2] ***New disturbance under the No Action Alternative is presented in Table 2.4-1.***

[3] ***Existing disturbance is presented in Table 2.2-1.***

[4] Interim reclamation estimates are based on the potential to reclaim 0.5 acre per new well pad, 27 feet ROW for new access roads, and all new Linear Facilities summarized in the table above.

2.6.1 Field Development Plan and Schedule

KMG and other operators would drill a maximum of 3,675 new wellbores in addition to the existing producing wells and approved/permitted wells yet to be drilled in the GNBPA as discussed in Section 2.4, No Action Alternative. **Figure 2.6-1** illustrates available locations for new wells at a 20-acre spacing. Although actual operations are subject to change as the project proceeds, KMG and other operators would drill additional wells at an average rate of approximately 358 wells per year for over 10 years or until the resource base is fully developed. The total number of wells that would be drilled during the life of the project or during any particular year would depend largely on factors outside of KMG's control such as permit approvals, production success, engineering technology, economic factors, commodity prices, rig availability, and lease stipulations. The productive life of each well is estimated to be approximately 30 to 50 years. KMG estimates that 3 percent of the drilled wellbores might be dry. A dry hole most commonly results from mechanical failure.

2.6.2 Alternative-specific Activities

2.6.2.1 Access Roads

The Proposed Action Alternative would result in the drilling of up to 3,041 wells on new well pads. An additional 634 wells would be deepened recompletions or twins of existing wells from existing well pads. Access to 3,041 new well pads, assuming an average road length of approximately 0.25 mile per well pad, would require construction of 760 miles of new roads.

2.6.2.2 Infill Drilling and Multiple-Well Pads

Infill Drilling

Infill drilling of vertical wells would be performed on 40-acre and 20-acre surface spacing throughout the GNBPA (i.e., with 16 to 32 surface well pads per section). KMG defines a 40-acre well pad as the first well pad located in a governmental 40-acre quarter-quarter section. A 20-acre pad is defined as the second well pad located in a 40-acre quarter-quarter section. Downhole well spacing would be based on KMG's reservoir engineering evaluation on an on-going basis and would be site-dependent, potentially ranging from 16 wells per section (40-acre spacing) to 64 wells per section (10-acre spacing) or more. A maximum of 3,041 new well pads would be constructed to achieve the combined 40-acre and 20-acre surface spacing assuming vertical wells. This EIS assumes 20-acre spacing for all 3,041 new well pads, which represents the maximum surface disturbance.

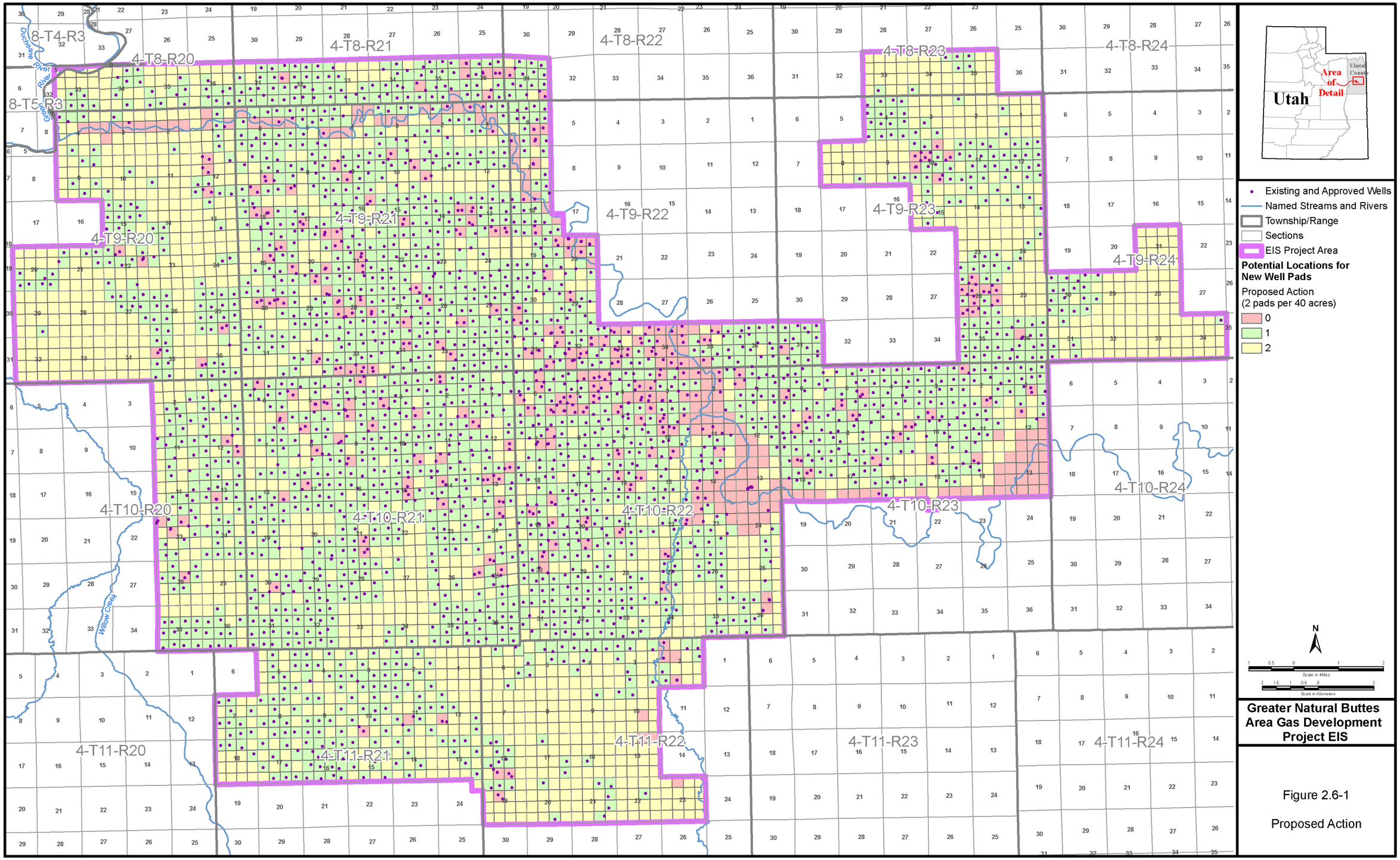
Mesaverde-only Completions

Under the Proposed Action Alternative, KMG would plan to drill 634 completions to the Mesaverde Formation by either deepening an existing Wasatch wellbore or by drilling a twin well on an existing well pad. KMG expects most of the Mesaverde-only completions would be located in T8S-R21E, T9S-R21E, T9S-R22E, T10S-R21E, T10S-R22E, and T10S-R23E.

Directional Drilling

Portions of the GNBPA pose environmental constraints to drilling a vertical well from the surface. KMG has made a preliminary determination of those areas based upon the following constraining factors:

- Topography, including steep slopes that preclude construction of a well pad for a vertically drilled well without major cuts-and-fills;
- The viewshed (line-of-sight from the centerline up to 0.5 mile on either side of the river) of the White River corridor, outside of the Indian Trust Lands; and
- Areas within 600 feet of the White River within the Indian Trust Lands.



Greater Natural Buttes Area Gas Development Project EIS

Figure 2.6-1

Proposed Action

Tuesday, February 10, 2009 7:30:34 AM
X:\0Projects\12100_013_Kerr_McGee_Greater_Natural_Buttes\Figures_Folder\PDEIS\Fig2_6-1_ProposedAction.mxd

In areas where the gas resources in the reservoirs warrant a downhole spacing of less than 20 acres based on reservoir engineering evaluation, or in those areas where environmental constraints preclude vertical wells, KMG would test and attempt to utilize directional drilling technology to drill from nearby 20-acre or 40-acre pads if such is technically and economically viable. It must be stressed that the decision of whether to drill an area to a downhole spacing less than 20 acres with directional wells would depend on KMG's ability to drill and develop the gas resources in an economically and technically viable manner because of the economically marginal nature of wells in the GNBPA. Analysis of the Proposed Action Alternative assumes vertical wells would be drilled at all locations.

KMG currently anticipates that most of the wells with a downhole spacing of 20 acres or less would be located in portions of T9S-R21E, T9S-R22E, T10S-R22E, and T10S-R23E, or in areas of environmental constraints discussed above. However, KMG may drill wells with a downhole spacing of 20 acres or less at any location within the GNBPA, as production success is evaluated during the life of the project. The downhole density of wells within the GNBPA would reflect effective reservoir drainage patterns for the GNBPA. However, the surface density of the KMG well pads would not exceed 32 pads per section.

KMG is currently using directional drilling techniques in development within the Bonanza Unit. Success in the Bonanza area in the east portion of the GNBPA does not necessarily indicate that directional drilling within the GNBPA would be successful.

An average of 15 drilling rigs would be operating in the GNBPA over a 10-year period to drill the 3,675 wells proposed by KMG and other operators. Each rig would average 24 wells per year. These wells would be in addition to 1,102 wells authorized by prior NEPA as described under the No Action Alternative.

Based on the need for 2.06 acre-feet per well, an estimated 7,571 acre-feet of fresh water would be required to drill and complete 3,675 wells or approximately 757 acre-feet each year for the projected 10-year drilling period. ***If half (or more) of this amount came from recycling, then approximately 380 acre-feet per year (or less) would need to be withdrawn for well drilling and completion from commercial sources mentioned in Section 2.5.3.4.***

If a location is shared with more than one well and fluid volumes so warrant, additional tanks may be installed to provide increased storage capacity with no increase in well pad size/disturbance. KMG may install a single larger separator on pads that share more than one well. A berm capable of containing 110 percent of the capacity of the largest tank would surround all tanks. All natural gas would be measured electronically, and KMG plans to install telemetry equipment to remotely operate and monitor wells, minimizing the number of wellsite visits.

Two mancamps of approximately 5 acres each (10 total acres) would be located within the GNBPA.

2.6.2.3 Gas Pipelines

Approximately 760 miles of natural gas gathering pipeline would be installed to transport natural gas from project wells to larger buried pipelines that connect to processing facilities. Approximately 722 miles (95 percent) of the surface natural gas gathering pipeline system would be placed in available access road ROWs. Approximately 38 miles (5 percent) of the natural gas gathering system would require cross-country routing outside of access road ROWs; cross-country routing would require a 20-foot ROW for construction. Approximately 35 miles of larger-diameter, buried transport pipeline would be constructed within a 75-foot-wide construction ROW that would overlap with other ROWs when possible.

2.6.2.4 Gas Compression and Processing

Two compression sites would be constructed to meet project compression needs within the GNBPA; each site would require approximately 20 acres for the life of the facility. These facilities would provide a total additional 79,000 hp of new compression; approximately half gas fired and half electrically driven.

2.6.2.5 Electrical Power Requirements

Under the Proposed Action Alternative, approximately 7.0 miles of overhead electric lines would be installed to provide power to the pumps at water disposal wellsites. The new power lines would be 35 kV distribution lines that would originate from the existing power grid. Pole mount transformers would be installed within 500 feet of each point of use to obtain 480-volt power for the pumps. The power lines would be installed within a 100-foot ROW. Surface disturbance associated with electric power line installation within the ROW would be reclaimed as soon as construction is completed.

2.6.2.6 Water Disposal Facilities

Up to 15 water disposal wells ***may be needed*** in the GNBPA on existing well pads or using existing well borings. Assuming an average disposal capacity of ***188 acre-feet per year (***4,000 BWPD***)*** for each disposal well, 15 disposal wells would have a combined capacity of ***2,817 acre-feet per year (***60,000 BWPD***)***. Although estimated future water production is difficult to predict because of variable water saturation conditions as the gas reservoir is produced and depleted, KMG has estimated that approximately ***1,385 acre-feet per year (***29,500 BWPD***)*** would be produced under the Proposed Action. Therefore, the proposed expansion of water disposal capacity would be more than adequate to accommodate the produced water from the project. ***If total evaporative pond capacity is used, then approximately 353 acre-feet per year (7,500 BWPD) would be disposed in ponds and 1,032 acre-feet per year (21,900 BWPD) would be disposed by underground injection.***

Disposal well locations would be chosen based on suitable subsurface rock formation properties and water quality data. Each new water disposal well would add approximately 0.2 acre of new disturbance to an existing well pad, for a total maximum new surface disturbance of 3.0 acres. Several produced water tanks would be added to the sites of two of the more centrally located disposal wells. Additional tanks would add approximately 3.0 acres to the existing well pad for a total new surface disturbance of approximately 6.0 acres.

Approximately 25 miles of 4- to 12-inch, buried polypropolene water flowlines would be installed within a 75-foot-wide ROW to interconnect all water management facilities including salt water disposal wells, existing evaporation/recycle ponds and centralized tank batteries.

Currently, produced water is transported by truck from wellsite storage tanks to disposal facilities. The average round trip distance between storage tanks and disposal facilities is estimated to be approximately 10 miles. Implementation of the Proposed Action would result in average annual additional produced water of approximately 10,744,414 bbls and would require approximately 107,444 annual disposal truck trips.

To reduce air quality impacts associated with water disposal truck traffic, approximately 587 miles of 3- to 6-inch polypropylene pipeline could be installed on the surface along side the surface natural gas gathering pipelines and within the 45-foot-wide access road ROWs. KMG would not implement construction of water pipelines on the ground surface until they identify a means of addressing the potential for freezing of water in the pipes. Installation of such surface pipelines would neither increase nor decrease the surface disturbance associated with the Proposed Action Alternative.

2.7 Resource Protection Alternative

A summary of surface disturbance associated with implementation of the Resource Protection Alternative is indicated in **Table 2.7-1**. The disturbance indicated in **Table 2.7-1** is new disturbance that would occur in addition to ***existing disturbance (Section 2.4) and new disturbance under*** the No Action Alternative ***(Section 2.4)***.

Table 2.7-1 Resource Protection Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility)	Surface Disturbance (acres)
Roads			
Access Roads[1]	594 miles	45 feet	3,238
Well Pads			
New Single Well Pads	1,484 each	2.5 acres	3,710
Twinned Well Pads (Additional Disturbance)	634 each	0.2 acre	127
Multi-well Pads (Additional Disturbance)	1,557 each	0.2 acre	311
Well Pad Subtotal	***3,675 each***		***4,148***
Construction/Production Facilities			
Mancamps	2 each	5 acres	10
Compressor Stations	2 each	20 acres	40
Water Tank Batteries	2 each	3 acres	6
Water Injection Facilities (Additional Disturbance)	15 each	0.2 acre	3
Facilities Subtotal			***59***
Linear Facilities			
Gas Gathering Pipelines - Common ROW	564 miles	0 feet	0
Gas Gathering Pipelines - Cross-country	30 miles	20 feet	72
Gas Transport Pipelines (Buried)	35 miles	75 feet	318
Water Gathering Pipelines - Common ROW (Surface)	458 miles	0 feet	0
Water Connecting Pipelines (Buried)	25 miles	75 feet	227
Electric Power Lines	7 miles	100 feet	85
Linear Facilities Subtotal			***702***
Resource Protection Alternative New Disturbance(acre)			***8,147***
GNBPA New Disturbance (%)			***5.0%***
No Action Alternative New Disturbance[2] (acre)			***4,702***
Existing Surface Disturbance[3] (acre)			***7,766***
Total Surface Disturbance (acre)			***20,615***
Total GNBPA Disturbed (%)			***12.7%***
Surface Disturbance Interim Reclamation Estimates[4]			
Reclaimable New Surface Disturbance (acre)			3,387
Reclaimable No Action New Surface Dist (acre)			1,753
Reclaimable Existing Surface Disturbance (acre)			3,267
Total Est. Reclaimable Surface Disturbance (acre)			8,407
Reclaimable Surface Disturbance (%)			41%
Reclaimable Surface Disturbance as % of GNBPA			5.2%

[1] Assume access road length of 0.4 mile/well pad for Resource Protection Alternative.

[2] ***New disturbance under the No Action Alternative is presented in Table 2.4-1.***

[3] ***Existing disturbance is presented in Table 2.2-1.***

[4] Interim reclamation estimates are based on the potential to reclaim 0.5 acre per new well pad, 27 feet ROW for new access roads, and all new Linear Facilities summarized in the table above.

2.7.1 Field Development Plan and Schedule

The Resource Protection Alternative would be similar to the Proposed Action, but places a limit on the maximum number of new well pad locations to 1 pad per 40 acres (maximum of 16 well pads per section). **Figure 2.7-1** illustrates the available locations for new wells at a 40-acre spacing. Based on proposed activities identified earlier as common to all action alternatives, KMG and other operators would drill a maximum of 3,675 new wellbores in addition to the existing producing wells and approved/permitted wells yet to be drilled in the GNBPA. In order to complete 3,675 new wellbores from a reduced number of surface well pad locations, directional drilling techniques would need to be implemented by the operators.

As discussed under the Proposed Action Alternative, KMG and other operators would drill additional wells at an average rate of approximately 358 wells per year over a period of 10 years or until the resource base is fully developed, with a maximum total of 3,675 wellbores. The total number of wells drilled during the life of the project or during any particular year would depend largely on factors outside of KMG's control. The estimated productive life of each well would be approximately 30 to 50 years, and 3 percent of the drilled wellbores might be dry principally due to mechanical failure.

The drilling schedule, well drilling and completion parameters, equipment and manpower requirements, compressor stations, water disposal facilities, buried water and gas pipelines, electric power facilities, and ancillary facilities would be as discussed under the Proposed Action Alternative.

The number of disturbance impacts associated with production facilities (mancamps, compressor stations, water tank batteries, and water disposal wells) as well as electrical power requirements is expected to be the same for the Resource Protection Alternatives as it would be for the Proposed Action Alternative.

2.7.2 Alternative-specific Activities

2.7.2.1 Access Roads

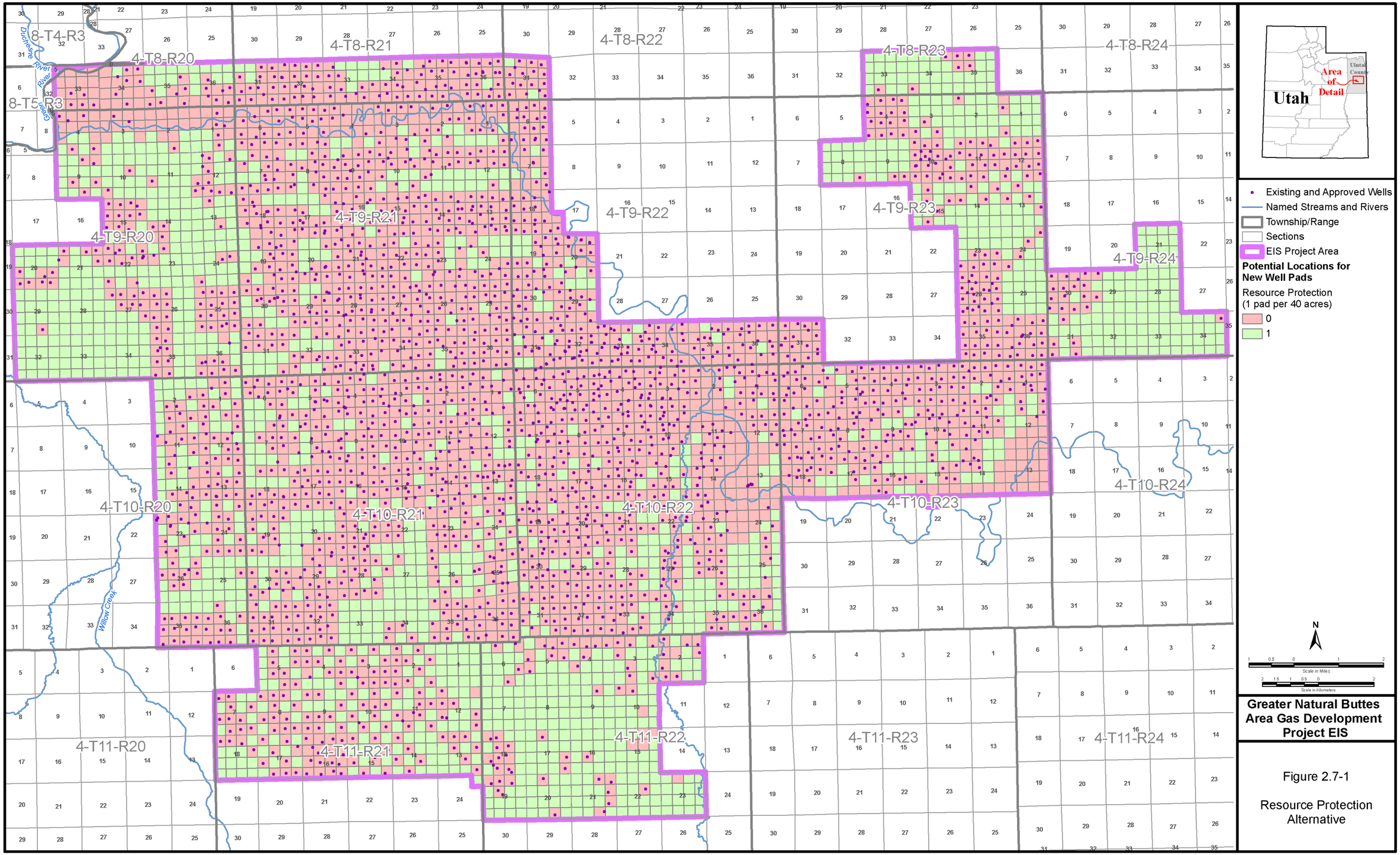
Approximately 594 miles of new access road would be constructed to a maximum of 1,484 new well pads that would be available under this alternative. Because fewer new well pads would be constructed under the Resource Protection Alternative than under the Proposed Action Alternative, the average new access road length would be approximately 0.4 mile.

2.7.2.2 Infill Drilling and Multiple-well Pads

Infill drilling would be performed on 40-acre surface spacing (maximum of 16 well pads per section) throughout the GNBPA using vertical and directional drilling techniques. The location of the 40-acre spaced well pads would reflect avoidance of the following constraining factors:

- Topography, including steep slopes that preclude construction of a well pad for a vertically drilled well without major cuts-and-fills;
- The viewshed of the White River corridor (line-of-sight from the centerline up to 0.5 mile along both sides of the river), outside of the Indian Trust Lands;
- Areas within 600 feet of the White River within the Indian Trust Lands; and
- Areas within the 100-year floodplain of the White River ***and Green River***, and 5 miles up major tributaries ***of the White River, regardless of surface ownership***.

The Resource Protection Alternative would reduce impacts to other resources by limiting disturbance to a total of 16 well pad locations per section in comparison to as many as 32 well pad locations per section under the Proposed Action Alternative.



Greater Natural Buttes Area Gas Development Project EIS

Figure 2.7-1

Resource Protection Alternative

Wednesday, March 12, 2008 9:37:49 AM
X:\0Projects\12100_013_Kerr_McGee_Greater_Natural_Buttes\APDEIS_Figures\Fig2_7-1_ResourceProtectionAlternative.mxd

As of October 2007, there were approximately 1,484 available 40-acre spacing locations for new well pads within the GNBPA. Under this alternative, it has been assumed that KMG would drill 634 Mesaverde-only completions from deepened recompletions or twinned wells on existing well pads as was the case for the Proposed Action. Limiting surface disturbance to 40-acre well pad spacing would reduce the number of possible new well pads from 3,041 to 1,484 under the Resource Protection Alternative. If full recovery of the natural gas resource requires the drilling of wellbores at a downhole spacing of 20 acres or less, then directional drilling techniques would be required under this alternative. Therefore, impact analysis of this alternative assumed 1,557 directionally drilled wellbores to establish the same number of wellbores (3,675) as the Proposed Action Alternative. ***Water requirements for well drilling and completion and for other consumptive purposes under this alternative would be the same as for the Proposed Action.***

2.7.2.3 Gas Pipelines

As was the case with the Proposed Action Alternative, surface gas gathering pipelines are assumed to be co-located with access road ROWs approximately 95 percent of the time and would be installed cross-country approximately 5 percent of the time. Under this alternative, approximately 564 miles of co-located and approximately 30 miles of cross-country surface pipeline would be installed. Approximately 35 miles of larger-diameter, buried transport pipeline would be constructed within a 75-foot-wide construction ROW that would overlap with other ROWs when possible.

2.7.2.4 Water Disposal Facilities

Produced water would be handled in the same manner as discussed under the Proposed Action Alternative. Because of differing numbers of well pads, wellbores, and road lengths, the volumes of produced water and amount of truck transport would differ. For this alternative, annual truck transport of produced water is estimated to be approximately 107,444 truckloads over an average of approximately 10 miles roundtrip, assuming an average truck capacity of 100 bbls. Average annual produced water from this alternative is estimated to be approximately 1,385 acre-feet ***per year***. ***If total evaporative pond capacity is used, then approximately 353 acre-feet per year (7,500 BWPD) would be disposed in ponds and 1,032 acre-feet per year (21,900 BWPD) would be disposed by underground injection.***

In the event that KMG were to proceed with construction of a water gathering pipeline system on the ground surface co-located within access road ROW disturbance, approximately 458 miles of surface pipeline could be constructed without increasing the surface disturbance. KMG would identify a solution to the issue of freeze protection prior to installation of aboveground water gathering pipelines. However, as with the Proposed Action Alternative, approximately 25 miles of buried connecting water flowlines within a 75-foot ROW would be needed to transport water to the water disposal wells.

2.8 Optimal Recovery Alternative

A summary of surface disturbance associated with implementation of the Optimal Recovery Alternative is indicated in **Table 2.8-1**. The disturbance indicated in **Table 2.8-1** is new disturbance that would occur in addition to ***existing disturbance (Section 2.2) and new disturbance under*** the No Action Alternative ***(Section 2.4)***.

Table 2.8-1 Optimal Recovery Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility	Surface Disturbance (acres)
Roads			
Access Roads[1]	1,627 miles	45 feet	8,875
Well Pads			
New Single Well Pads	12,812 each	2.5 acres	32,030

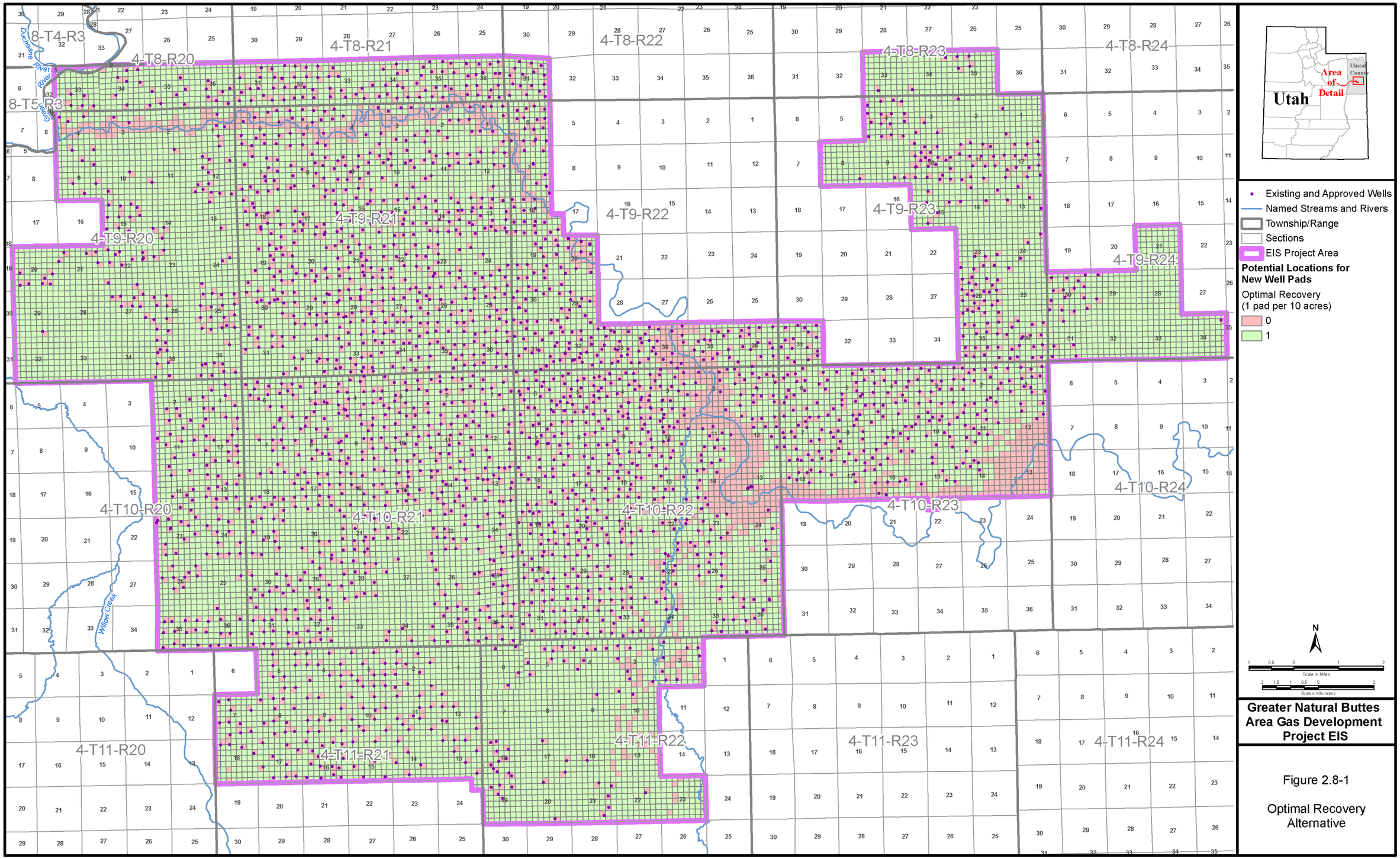
Table 2.8-1 Optimal Recovery Alternative Summary of New Surface Disturbance

New Facilities	Multiplier (number or miles)	Size (ROW width [feet] or acres/facility	Surface Disturbance (acres)
Twinned Well Pads (Additional Disturbance)	634 each	0.2 acre	127
Multi-well Pads (Additional Disturbance)	0 each	0.2 acre	0
Well Pad Subtotal	***13,446 each***		***32,157***
Construction/Production Facilities			
Mancamps	2 each	5 acres	10
Compressor Stations	5 each	20 acres	100
Water Tank Batteries	5 each	3 acres	15
Water Injection Facilities (Additional Disturbance)	25 each	0.2 acre	5
Facilities Subtotal			***130***
Linear Facilities			
Gas Gathering Pipelines – Common ROW	1,546 miles	0 feet	0
Gas Gathering Pipelines – Cross-country	81 miles	20 feet	197
Gas Transport Pipelines (Buried)	70 miles	75 feet	636
Water Gathering Pipelines – Common ROW (Surface)	1,256 miles	0 feet	0
Water Connecting Pipelines (Buried)	50 miles	75 feet	455
Electric Power Lines	14 miles	100 feet	170
Linear Facilities Subtotal			***1,458***
Optimal Recovery Alternative New Disturbance			***42,620***
GNBPA New Disturbance (%)			***26%***
No Action Alternative New Disturbance[2] (acre)			***4,702***
Existing Surface Disturbance[3] (acre)			***7,766***
Total Surface Disturbance (acre)			***55,088***
Total GNBPA Disturbed (%)			***34%***
Surface Disturbance Interim Reclamation Estimates[4]			
Reclaimable New Surface Disturbance (acre)			13,189
Reclaimable No Action New Surface Dist (acre)			1,753
Reclaimable Existing Surface Disturbance (acre)			3,267
Total Est. Reclaimable Surface Disturbance (acre)			18,209
Reclaimable Surface Disturbance (%)			33%
Reclaimable Surface Disturbance as % of GNBPA			11.2%

[1] Assume access road length of 0.127 mile/well pad.
[2] ***New disturbance under the No Action Alternative is presented in Table 2.4-1.***
[3] ***Existing disturbance is presented in Table 2.2-1.***
[4] Interim reclamation estimates are based on the potential to reclaim 0.5 acre per new well pad, 27 feet ROW for new access roads, and all new Linear Facilities summarized in the table above.

2.8.1 Field Development Plan and Schedule

The Optimal Recovery Alternative is designed to maximize recovery of the gas resource by increasing the number of wellbores to achieve 10-acre surface and downhole spacing throughout the GNBPA. **Figure 2.8-1** illustrates the available locations for new wells. Based on proposed activities identified as common to all alternatives, KMG and other operators would drill an estimated 13,446 new wellbores in addition to the existing producing wells and approved/permitted wells yet to be drilled in the GNBPA. KMG's activities would remain largely as outlined under the Proposed Action Alternative. Additional wells would be drilled at an average rate of approximately 672 wells per year using 28 drilling rigs and would be drilled over



Greater Natural Buttes Area Gas Development Project EIS

Figure 2.8-1

Optimal Recovery Alternative

Tuesday, February 10, 2009 7:32:09 AM
X:\0Projects\12100_013_Kerr_McGee_Greater_Natural_Buttes\Figures_Folder\PDEIS\Fig2_8-1_OptimalRecoveryAlternative.mxd

a period of approximately 20 years or until the resource base is fully developed. The total number of wells drilled during the life of the project or during any particular year would depend largely on factors outside of KMG's control. The estimated productive life of each well would be approximately 30 to 50 years, and 3 percent of the drilled wellbores might be dry principally due to mechanical failure.

The drilling schedule, well drilling and completion parameters, equipment and manpower requirements, compressor stations, water disposal facilities, buried water and gas pipelines, electric power facilities, and ancillary facilities would be similar to that discussed under the Proposed Action Alternative. However, in some cases more facilities would be constructed because of the higher number of wells and increased gas volumes produced.

2.8.2 Alternative-specific Activities

2.8.2.1 Access Roads

Approximately 1,627 miles of new access road would be constructed to 12,812 new well pads. Because many more well pads would be constructed than under the Proposed Action Alternative, average access road length would be shorter because of the greater well pad density. For this alternative, the estimated average new access road length would be 0.127 mile.

2.8.2.2 Infill Drilling of Vertical Wells

For onshore reservoirs, drilling individual vertical wells typically is the most technically and cost efficient method of recovering the gas resource. The location of the well pads would reflect avoidance of the following constraining factors:

- Topography, including steep slopes that preclude construction of a well pad for a vertically drilled well;
- The viewshed (line-of-sight from the centerline up to 0.5 mile along both sides of the river) of the White River corridor, outside of the Indian Trust Lands; and
- Areas within 600 feet of the White River within the Indian Trust Lands.

It has been estimated that approximately 470 locations at 10-acre spacing could not be drilled from vertical well pads in these constrained areas. Recovery of the natural gas resource would require the use of directional drilling techniques, which ***the BLM has assumed*** KMG ***would not implement*** within the GNBPA ***under this alternative***. Accordingly, these locations have not been analyzed in this EIS.

All of the rest of the undrilled GNBPA would be assumed to be drilled using vertical wells from individual well pads. Accounting for 1,562 existing productive wells and 1,102 additional approved wells drilled under the No Action Alternative, there would be room for 12,812 new well pads drilled on 10-acre surface spacing.

Approximately 27,699 acre-feet of water would be required to drill and complete the 13,446 total wells, or approximately 1,385 acre-feet annually during the 20 years required to complete this Optimal Recovery Alternative. ***If half of this amount came from recycled sources, then approximately 692 acre-feet per year of fresh water would need to be withdrawn from commercial sources mentioned in Section 2.5.3.4. KMG indicates that more than half of the water needed for well drilling and completion could be recycled, which would reduce fresh water withdrawal.***

The number of mancamps needed for the Optimal Recovery Alternative would be the same as that needed for all other action alternatives; two camps at 5 acres each.

2.8.2.3 Gas Pipelines

A total of approximately 1,627 miles of natural gas surface gathering pipeline would be installed to transport natural gas from project wells to larger buried pipelines that connect to processing facilities. Approximately 1,546 miles (95 percent) would be placed in available access road ROWs, and approximately 81 miles (5 percent) would require cross-country routing outside of access road ROWs. Cross-country routing would require a 20-foot ROW for construction. Approximately 70 miles of larger-diameter, buried transport pipeline would be constructed within a 75-foot-wide construction ROW that would overlap with other ROWs when possible.

2.8.2.4 Gas Compression and Processing

Five compression sites would be constructed to meet project compression needs within the GNBPA; each site would require approximately 20 acres for the life of the facility. These facilities would provide a total additional 197,500 hp of compression; half gas-fired and half electrically driven.

2.8.2.5 Electrical Power Requirements

Under the Optimal Recovery Alternative, approximately 14.0 miles of overhead electric lines would be installed to provide power to the pumps at the proposed water disposal wellsites. The new power lines would be 35-kV distribution lines that would originate from the existing power grid. Pole mount transformers would be installed within 500 feet of each point of use to obtain 480-volt power for the pumps. The power lines would be installed within a 100-foot ROW. Surface disturbance associated with electric power line installation within the ROW would be reclaimed as soon as construction is completed.

2.8.2.6 Water Disposal Facilities

Under this alternative, 25 new disposal wells would be drilled in the GNBPA on existing well pads or using existing well borings located in Sections 19 through 36, T9S, R21E. Locations would be chosen based on suitable subsurface rock properties and water quality data. Sites of five of the more centrally located existing or proposed produced water disposal wells would contain several produced water storage tanks. Approximately 50 miles of 4- to 12-inch, buried polypropolene pipe water flowlines would be installed within a 75-foot-wide ROW to interconnect all new and existing water management facilities including salt water disposal wells, evaporation/recycle ponds, and centralized tank batteries.

Transport of produced water would be handled in the same manner as discussed under the Proposed Action Alternative. For this alternative, annual truck transport of produced water is estimated to be approximately 393,114 truckloads over an average of approximately 10 miles roundtrip, assuming an average truck capacity of 100 bbls. ***Produced water volume would be an estimated 5,067 acre-feet per year (107,700 BWPD). If total evaporative pond capacity is used, then approximately 353 acre-feet per year 7,500 BWPD) would be disposed in ponds and 4,714 acre-feet per year (100,200 BWPD) would be disposed by underground injection.***

In the event that KMG were to proceed with construction of a surface water gathering pipeline system co-located within access road ROW disturbance, similar to that described for the Proposed Action, approximately 1,256 miles of surface pipeline would be constructed.

2.9 Alternatives Considered but Eliminated from Further Consideration

The BLM considered two alternatives to the proposed project that were not carried forward for detailed analysis in subsequent chapters of this document. The following sections describe these alternatives and provide the rationale for why the BLM eliminated the alternatives from further detailed consideration.

No Further Development: The BLM considered an alternative under which no further development would take place in the GNBPA. This alternative was eliminated from detailed analysis because ongoing oil and

gas development continues on valid leases within the GNBPA as disclosed under existing NEPA decision documents (see Section 2.4.1). The decisions in the existing NEPA documents are not being revisited under this EIS. The no further development alternative is frequently mistaken for the No Action Alternative, which is required to be analyzed under NEPA. For this project, the No Action Alternative would occur if the BLM were to deny KMG's proposal, and development would continue in the GNBPA under existing NEPA disclosures. The No Action Alternative is fully analyzed in this document (Section 2.4 and analysis sections in Chapter 4).

Phased Development: The BLM considered a phased development alternative, which was intended to rotate concentrated disturbance activities through smaller, pre-defined areas (subareas), while the remainder of the GNBPA would be less impacted than under the Proposed Action. Under this alternative, oil and gas development activities would be restricted to one of several subareas within the GNBPA boundary. One subarea at a time would be open to oil and gas construction and development activities for a limited time period, after which construction and development activities would cease. An indicator, such as successful interim reclamation within a subarea, would be required to be met prior to developing a new subarea. Oil and gas extraction and processing would continue (i.e., operational activities) in the subarea, while construction and development activities would move to another subarea. An additional intent was to encourage concurrent and efficient reclamation of surface disturbance.

For the following reasons, the BLM eliminated this alternative from further detailed analysis in this EIS:

- Phased development could not be imposed by the BLM on state, Tribal, and private lands within the GNBPA. These lands make up almost one-half (45 percent) of the GNBPA, thereby reducing the benefit of a phased development approach.
- The BLM would still be required to process "reasonable access" ROW applications for development of private and state leases within the subareas not currently being developed (BLM Manual, Part 2800.06 "Policy" [D], allowing owners of non-federal lands surrounded by public lands managed under the FLPMA to develop for the reasonable use and enjoyment of these non-federal lands).
- Phased development could delay benefits to surface owners within the GNBPA (e.g., payments to the Ute Tribe for surface disturbance activities). In addition, job preference for Ute Tribe members when work activity occurs on Tribal lands could be delayed.
- The GNBPA is primarily located within an already developed field. The Proposed Action would downspace existing development. Phased development would concentrate traffic and drilling activities in the active subarea, but production and maintenance activities in the existing field would continue regardless of subarea.
- Under a phased development scenario operators would be unable to return to subareas where construction and development activity has ceased. This would prevent redevelopment of a subarea in the event that a change in commodity price or an improvement in drilling technology were to make the subsurface resource that was previously passed over economically viable.
- Concentrated development under a phase development alternative would focus surface disturbance impacts within individual grazing allotments. This could result in rapid reduction in forage and a corresponding reduction in animal unit months (AUMs).

2.10 Comparison of Alternatives

A comparison of disturbance within the GNBPA associated with the four alternatives is provided in **Table 2.10-1**. Impacts by resource associated with the alternatives are provided in **Table 2.10-2**.

Table 2.10-1 Disturbance Comparison for GNBPA Alternatives (Excluding Existing Condition)

New Facilities	Size (ROW width [feet] or acres/facility)	New Surface Disturbance by Alternative							
		No Action		Proposed Action		Resource Protection		Optimal Recovery	
		Multiplier (number or miles)	Disturbance (acres or % of GNBPA)	Multiplier (number or miles)	Disturbance (acres or % of GNBPA)	Multiplier (number or miles)	Disturbance (acres or % of GNBPA)	Multiplier (number or miles)	Disturbance (acres or % of GNBPA)
Roads									
Access Roads[1]	45 feet	276 miles	1,503	760 miles	4,147	594 miles	3,238	1,627 miles	8,875
Well Pads									
New Single Well Pads	2.5 acres	1,102 each	2,755	3,041 each	7,603	1,484 each	3,710	12,812 each	32,030
Twinned Well Pads (Additional Disturbance)	0.2 acre	0 each	0	634 each	127	634 each	127	634 each	127
Multi-well Pads (Additional Disturbance)	0.2 acre	0 each	0	0 each	0	1,557 each	311	0 each	0
Well Pad Subtotal		1,102 each	2,755	3,675 each	7,729	3,675 each	4,148	13,446 each	32,157
Construction/Production Facilities									
Mancamps	5 acres	0 each	0	2 each	10	2 each	10	2 each	10
Compressor Stations	20 acres	6 each	120	2 each	40	2 each	40	5 each	100
Water Tank Batteries	3 acres	8 each	24	2 each	6	2 each	6	5 each	15
Water Injection Facilities (Additional Disturbance)	0.2 acre	0 each	0.0	15 each	3	15 each	3	25 each	5
Construction/Production Facilities Subtotal			144		59		59		130
Linear Facilities									
Gas Gathering Pipelines – Common ROW	0 feet	262 miles	0	722 miles	0	564 miles	0	1,546 miles	0
Gas Gathering Pipelines – Cross-country	20 feet	14 miles	33	38 miles	92	30 miles	72	81 miles	197
Gas Transport Pipelines (Buried)	75 feet	0 miles	0	35 miles	318	35 miles	318	70 miles	636
Water Gathering Pipelines – Common ROW (Surface)	0 feet	0 miles	0	587 miles	0	458 miles	0	1,256 miles	0
Water Connecting Pipelines (Buried)	75 feet	26 miles	236	25 miles	227	25 miles	227	50 miles	455
Electric Power Lines	100 feet	2.5 miles	30	7 miles	85	7 miles	85	14 miles	170
Linear Facilities Subtotal			300		722		702		1,458
New Surface Disturbance (acre)			4,702		12,658		8,147		42,620
GNBPA New Disturbance (%)			2.9%		7.8%		5.0%		26.2%
No Action Alternative New Disturbance (acre)					4,702		4,702		4,702
Existing Surface Disturbance (acre)			7,766		7,766		7,766		7,766
Total Surface Disturbance (acre)			12,468		25,125		20,615		55,088
Total GNBPA Disturbed (%)			7.7%		15.4%		12.7%		33.8%
Surface Disturbance Interim Reclamation Estimates[2]									
Reclaimable New Surface Disturbance (acre)			1,753		4,731		3,387		13,189
Reclaimable No Action New Surface Dist (acre)					1,753		1,753		1,753
Reclaimable Existing Surface Disturbance (acre)			3,267		3,267		3,267		3,267
Total Est. Reclaimable Surface Disturbance (acre)			5,020		9,751		8,407		18,209
Reclaimable Surface Disturbance (%)			40.3%		39%		41%		33%
Reclaimable Surface Dist as % of GNBPA			3.1%		6.0%		5.2%		11.2%

[1] Assume access road length of 0.25 mile/well pad for No Action and Proposed Action; 0.4 mile/well pad for Resource Protection Alternative; 0.127 mile/well pad for Optimal Recovery Alternative.

[2] Interim reclamation estimates are based on the potential to reclaim 0.5 acre per new well pad, 27 feet ROW for new access roads, and all new Linear Facilities summarized in the table above.

Table 2.10-2 Impact Comparison by Resource for All Alternatives

Resource	No Action Alternative	Proposed Action Alternative	Resource Protection Alternative	Optimal Recovery Alternative	Additional Discussion
Air Quality					
Air Quality (exceed NAAQS)	No	No	No	Potential[1]	Section 4.1
Acid Deposition (exceed U.S. Forest Service [USFS] threshold)	Yes (1 area)[2]	Yes (1 area)[2]	Yes (1 area)[2]	Yes (1 area)[2]	Section 4.1
Visibility (Class I)	Cumulative impacts > 1.0 deciview (dv)	Incremental impacts < 1.0 dv	Incremental impacts < 1.0 dv	Incremental impacts < 1.0 dv	Section 4.1
Visibility (Class II)	Cumulative impacts > 1.0 dv	Incremental impacts > 1.0 dv at 2 areas	Incremental impacts > 1.0 dv at 2 areas	Incremental impacts > 1.0 dv at 2 areas	Section 4.1
Greenhouse Gas (GHG) Emissions (10^3 tonne carbon dioxide ***[CO_2]*** equivalents [CO_2e]/year)	1,761	2,754	2,754	5,485	Section 4.1
Cultural Resources and Native American Traditional Values					
Sites potentially encountered (incremental due to new surface disturbance)	52	142	90	475	Section 4.2
Geology					
Recoverable Gas Resources Over the Life of the wells (trillion cubic feet [Tcf])	1.41	6.07	6.07	15.44	Section 4.3
Recoverable Condensate Resources Over the Life of the Wells (million bbls)	22.3	86.5	86.5	118	Section 4.3
Land Use					
White River Special Recreation Management Area (SRMA) (incremental acres disturbed)	7.8	49	32	164	Section 4.4
Paleontology					
Potential Fossil Yield Classification (PFYC) Class 4 or 5 areas (potential incremental acres disturbed)	4,467	12,025	7,740	40,489	Section 4.5
Range Resources					
AUMs Lost – BLM	352	947	609	3,186	**Tables 4.6-1**, **4.6-2**, **4.6-4**, and **4.6-6**
AUMs Lost – BIA	26	71	46	239	**Tables 4.6-1**, **4.6-2**, **4.6-4**, and **4.6-6**
Total AUMs Lost	378	1,018	655	3,425	
Number Rangeland Improvements Impacted (BLM land only)	***12***	26	15	27	**Tables 4.6-3**, **4.6-5**, and **4.6-7**
Socioeconomics					
Energy Resource Recovery					Section 4.8 and **Table 4.8-1**
Natural Gas (Tcf)	1.41	6.07	6.07	15.44	
Oil Condensates (million bbl)	22.3	86.5	86.5	117.9	
Projected end of production (year)	2051	2059	2059	2066	
Employment (number jobs)					Section 4.8 and **Tables 4.8-5**, **4.8-9**, and **4.8-13**
Peak – development	1,790	4,302	4,302	9,024	
Average – production	239	875	875	1,712	

Table 2.10-2 Impact Comparison by Resource for All Alternatives

Resource	No Action Alternative	Proposed Action Alternative	Resource Protection Alternative	Optimal Recovery Alternative	Additional Discussion
Population – Duchesne and Uintah counties					Section 4.8 and **Tables 4.8-6**, **4.8-10**, and **4.8-14**
Peak – development	2,585	5,590	5,590	8,368	
Average – production	450	1,508	1,508	2,732	
Temporary and permanent housing demand in Duchesne and Uintah counties during development (units)	1,593	3,447	3,447	5,159	Section 4.8 and **Tables 4.8-6**, **4.8-10**, and **4.8-14**
Grazing – Reduction in annual cash farm receipts ($24 per AUM lost)	As much as $7,632 lost	As much as $24,432 lost	As much as $15,720 lost	As much as $82,200 lost	Section 4.8
Public Sector Revenues – Cumulative Life of Field[3] (millions of 2006 dollars)					Section 4.8 and **Tables 4.8-8**, **4.8-12**, and **4.8-16**
Ad Valorem Taxes	89.2	343.8	343.8	856.1	
Utah Severance Taxes	270.5	1,146.7	1,146.7	2,709.5	
Federal and Tribal Mineral Royalties	417.9	2,692.4	2,692.4	6,33***2.8***	
State Public School Fund Royalties	158.9	673.1	673.1	1,582.5	
Combined Public Sector Revenues	1,154.3	4,856.0	4,856.0	11,481.0	
Percent Increase over No Action	N/A	321	321	895	
Soils					
High Constraint (incremental acres disturbed)	4,396	11,835	7,618	39,849	**Table 4.9-1**, **Appendix F**
Moderate Constraint (incremental acres disturbed)	141	380	244	1,279	
Low Constraint (incremental acres disturbed)	165	443	285	1,492	
Transportation and Access					
New Access Roads (miles)	276	760	594	1,627	Section 4.10
Increase in Traffic Volume at Full Production (total number vehicle miles)	0	20,948	20,948	59,162	Section 4.10
Number of Annual Incidents (mostly minor accidents and spills)	22	58	58	201	Section 4.10
Vegetation					
Uinta Basin hookless cactus potential preferred habitat (estimated incremental acres disturbed)	1,***600***	4,***266***	2,***667***	***13,866***	Section 4.11
Vegetation Type (estimated incremental acres disturbed)					**Tables 4.11-1**, **4.11-2**, **4.11-3**, **4.11-4**
Salt-desert shrubland	1,932	5,279	3,437	17,775	
Sagebrush shrubland	1,663	4,548	2,961	15,313	
Grassland	455	1,246	811	4,194	
Cliff/Canyon	217	593	386	1,997	
Riparian	143	189	29	637	
Pinyon-juniper woodland	82	225	147	758	
Agriculture	30	81	53	274	
Barren	178	490	319	1,650	
Developed	2	7	4	22	

Table 2.10-2 Impact Comparison by Resource for All Alternatives

Resource	No Action Alternative	Proposed Action Alternative	Resource Protection Alternative	Optimal Recovery Alternative	Additional Discussion
Visual Resources					
Visual Resource Management (VRM) Class II areas on federal lands (incremental acres disturbed)	0	91	58	305	Section 4.12
Incremental Disturbance Visible from (acres):					Section 4.12
Boaters on the White River	1,287	3,461	2,218	11,536	
Goblin City Overlook	140	377	242	1,257	
Water Resources					
100-year Floodplains (incremental acres disturbed)	325	288	0	1,510	Section 4.13
Total Water Use (acre-feet/year)	***454***	***757***	***757***	***1,385***	***Section 4.13***
Produced Water Withdrawals (acre-feet per year)	***415***	***1,385***	***1,385***	***5,067***	***Sections 2.4.2.5, 2.6.2.6, 2.7.2.4, and 2.8.2.6***
Produced Water Injected (acre-feet per year)	***62***	***1,032***	***1,032***	***4,714***	***Sections 2.4.2.5, 2.6.2.6, 2.7.2.4, and 2.8.2.6***
Wilderness Characteristics					
BLM White River Natural Area (incremental acres disturbed)	0	0	0	0	Section 4.14
Non-wilderness Study Area Lands with Wilderness Characteristics (estimated incremental acres disturbed)	81	217	139	724	Section 4.14
Wildlife Resources					
Big Game Habitat (estimated incremental acres disturbed)					**Tables 4.15-1**, **4.15-3**, **4.15-5**, and **4.15-7**
Pronghorn Year-long Crucial	3,183	10,264	6,607	34,562	
Pronghorn Year-long Substantial	67	179	116	604	
Mule Deer Year-long Crucial	553	1,488	958	5,011	
Mule Deer Winter Substantial	68	183	118	615	
Elk Winter Substantial	9	24	16	82	
Rocky Mountain Bighorn Sheep Year-long Crucial	781	2,103	1,354	7,082	
Bison Year-long Crucial Range	3,406	9,168	5,901	30,869	
Potential White-tailed Prairie Dog Habitat (estimated incremental acres disturbed)	4,258	11,644	7,581	39,206	Section 4.15
Greater Sage-grouse Habitat (estimated incremental acres disturbed)					**Tables 4.15-2**, **4.15-4**, **4.15-6**, and **4.15-8**
2.0 Mile Lek Buffer	442	1,190	766	4,007	
Nesting	675	1,817	1,169	6,117	
Brooding	1,782	4,797	3,088	16,153	
Winter	1,356	3,649	2,349	12,288	

Table 2.10-2 Impact Comparison by Resource for All Alternatives

Resource	No Action Alternative	Proposed Action Alternative	Resource Protection Alternative	Optimal Recovery Alternative	Additional Discussion
Fisheries Resources					
Estimated total water depletions for life of the project (acre/feet)	2,270	7,571	7,571	27,700	Section 4.15

[1] 2006 meteorological data show modeled concentrations of ozone between 76 and 79 ppb; 2005 meteorological data show modeled concentrations of ozone below 76 ppb.

[2] Modeled deposition from action alternatives does not exceed Federal Land Managers' Air Quality Related Values Workgroup (FLAG) thresholds, except for Mesa Verde National Park, which is predicted to exceed thresholds for the No Action Alternative.

[3] The public sector revenue projections assume constant natural gas prices of $4.59/thousand cubic feet (Mcf) and $45/barrel for liquids. However, energy prices fluctuate over time. Actual sector revenues could be higher or lower than shown, depending on future prices and production. Such variance would affect all alternatives.