MBPA DEIS Chapter 2 Table of Contents

Attachment 1- Figures

2.0 PROPOSED ACTION AND ALTERNATIVES

This chapter describes the Proposed Action and three other alternatives that include standard development and production activities for oil and gas resources in the MBPA. The range of alternatives was formulated to address issues and concerns raised during scoping, except for the No Action alternative, which was included to provide a baseline for comparison of alternatives.

The alternatives include:

- Alternative A – Proposed Action (Newfield's Plan as constrained by the regulatory requirements listed in **Table 2.1-1**)
- Alternative B – No Action Alternative
- Alternative C – Field-wide Electrification
- Alternative D – Resource Protection Alternative

Alternative A is derived from Newfield's proposed plan for oil and gas development. Alternative C is similar to Alternative A, except it would incorporate a component for field-wide electrification. Alternative D would generally incorporate similar construction, operational, decommissioning, and reclamation components as the Proposed Action and Alternative C, but with additional considerations applied to those actions taking place on federal lands. The BLM has identified Alternative D as the agency preferred alternative because it best addresses issues raised in scoping about potential impacts to resources while meeting the purpose and need for the Project.

Under Alternative B - No Action alternative, the existing rate of drilling would continue under currently approved authorizations on Federal mineral estate. Development would continue on State and private lands or minerals. Reasonable access across BLM-administered surface to proposed well pads and facilities on State and private lands or minerals would continue under the No Action alternative, as allowed by Federal regulations.

Each of the alternatives is discussed based on alternative-specific activities, schedule, design features, and surface disturbance. It is notable that the proposed surface locations for well pads, pipeline corridors, utility corridors, access roads, and other surface facilities are conceptual at this point. These locations have been illustrated on the alternative-specific maps (**Figures 2-1** through **2-4 – Attachment 1**) for analytical and impact evaluation purposes only in this EIS. Actual locations for well pads, access roads, ROWs, and other surface facilities would be determined at the Project implementation phase.

2.1 MANAGEMENT ACTIONS COMMON TO ALL ACTION ALTERNATIVES

Table 2.1-1 provides a description of the regulatory requirements and standard operating practices that would be applied under all alternatives. The table is subdivided by requirements and commitments specific to pre-drilling, construction, drilling, completion, production, interim reclamation and maintenance, and final reclamation and abandonment. The measures listed under each of these stages are then further subdivided into a list of regulatory requirements.

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Table 2.1-1. Regulatory Requirements Common to All Action Alternatives

Implementing Authority/ Regulation/Statute	Description of Requirement
Pre-drilling	
U.S. Environmental Protection Agency (EPA) Spill Prevention Control and Countermeasures (SPCC) Regulations (40 CFR 112)	▪ Newfield would implement and adhere to SPCC plans and provide personnel with an orientation to ensure they are aware of the potential effects of accidental spills, as well as the appropriate recourse if a spill does occur (40 CFR 112). Newfield currently adheres to the EPA SPCC regulations through development of SPCC plans, ongoing training and routine inspections of all existing and new well sites/facilities that are subject to the rule. Newfield will develop Facility Response Plans (FRP) for each Gas Oil Separation Plant (GOSP) as required by 40 CFR 112.20 & 112.21.
Utah Department of Environmental Quality-Division of Water Quality (UDEQ-DWQ), U.S. Army Corps of Engineers (USACE), Section 404, and Federal Water Pollution Control Act (Clean Water Act) (33 USC 1251, et seq.)	▪ Any disturbances to wetlands and/or waters of the United States would be authorized by the UDEQ-DWQ, in cooperation with the USACE Office. Section 404 permits would be secured as necessary prior to disturbance.
Occupational Safety and Health Administration (OSHA) Regulations (29 CFR 1910.1200)	▪ Newfield would institute its own internal Hazard Communication Program (HCP) for its personnel and require that subcontractor programs be in compliance with Newfield's HCP. In addition, a Material Safety Data Sheet (MSDS) for every chemical or hazardous material brought on-site would be kept on-site or on file at Newfield's Field Office (FO).
BLM/U.S. Forest Service (USFS) Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Existing topography would be used to screen roads, pipeline corridors, drill rigs, wells, and production facilities from view where practical. Newfield would paint all aboveground production facilities with approved colors (e.g. specified standard environmental colors) to blend with adjacent terrain, except for structures that require safety coloration in accordance with OSHA requirements.
Construction	
BLM, Onshore Oil and Gas Order No. 1 (43 CFR 3160)	▪ On federal land, operators would prepare and submit individual comprehensive drill-site design plans for BLM approval. These plans would show the drill location layout over the existing topography; dimensions of the locations, volumes, and cross sections of cut and fill; location and dimensions of reserve pits; existing drainage patterns; and access road egress and ingress. Plans and shapefiles would be submitted and approved prior to initiation of construction. ▪ Well pads and associated roads and pipelines would be located to avoid or minimize impacts in areas of important ecological value (e.g., sensitive species habitats and wetland/riparian areas).

Implementing Authority/ Regulation/Statute	Description of Requirement
BLM Manual 9113—Roads; BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Roads on BLM surface would be constructed as described in BLM Manual 9113. Running surfaces of roads may be graveled if the road base does not already contain sufficient aggregate. ▪ Existing roads would be used when the alignment is acceptable for the proposed use. Generally, roads would be required to follow natural contours and provide visual screening by constructing curves, etc. All roads on BLM managed lands would be reclaimed to BLM standards.
BLM Manual, Section 8400 (43 CFR 2802); BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Pipeline rights-of-way (ROWs) would be located within existing ROWs whenever possible. Aboveground facilities that do not require safety coloration would be painted with appropriate non-reflective standard environmental colors, as specified by the authorized officer (AO). Topographic screening, vegetation manipulation, project scheduling, and traffic-control procedures may all be employed as specified by the AO to further reduce visual impacts.
BLM Regulations (43 CFR 2802) regarding applications for ROWs; BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Salvage and subsequent replacement of topsoil would occur for surface-disturbing activities wherever practical.
USACE, Section 404, Federal Water Pollution Control Act (Clean Water Act) (33 USC 1251, et seq.)	▪ Where disturbance of regulated U.S. waters cannot be avoided, Newfield would obtain CWA Section 404 permits as required. Operations would be conducted in conformance with the requirements of the approved permits.
BLM Regulations (36 CFR 800) implementing Section 106; National Historic Preservation Act (NHPA) (16 USC 470, et seq.)	▪ If cultural resources are located within frozen soils or sediments that preclude the possibility of adequately recording or evaluating the find, construction would cease and the site would be protected for the duration of frozen soil conditions. Recordation, evaluation, and recommendations concerning further management would be made to the AO following natural thaw. The AO would consult with the affected parties, and construction would resume once management of the threatened site has been finalized and a Notice to Proceed has been issued.
BLM Manual 9112 (Bridges and Major Culverts) and Manual 9113 (Roads); BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Streams/channels crossed by roads would have culverts installed at all appropriate locations as specified in BLM Manuals 9112 and 9113. Low-water crossings can be effectively accomplished by dipping the road down to the bed of the drainage.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 4	▪ Prudent use of erosion-control measures, including diversion terraces, riprap, matting, temporary sediment traps, and water bars would be employed by Newfield as necessary and appropriate to control surface runoff generated at well pads. If necessary, Newfield would treat diverted water in detention ponds prior to release to meet applicable state or federal standards. ▪ Reserve pits would be constructed to ensure protection of surface water and groundwater. All reserve pits would be lined using liners of at least 16-mil thickness. Additional felt padding would be used as necessary, at the discretion of the AO. ▪ Appropriate erosion control and revegetation measures would be employed. Grading and landscaping would be used to minimize slopes, and slope stabilizers would be installed on disturbed slopes in areas with unstable soils where seeding alone may not adequately control erosion. Erosion-control efforts would be monitored by Newfield, and necessary modifications made to control erosion. ▪ Diversion structures, mulching, and terracing would be installed as needed to minimize erosion. In-stream protection

Implementing Authority/ Regulation/Statute	Description of Requirement
	structures (e.g., drop structures) in drainages crossed by a pipeline would be installed as appropriate to prevent erosion. ▪ Newfield would incorporate proper containment of condensate and produced water in tanks and drilling fluids in reserve pits and locate staging areas for storage of equipment away from drainages to prevent potential contaminants from entering surface waters.
Drilling	
Utah Department of Transportation (UDOT) Standards and Specifications	▪ Load limits would be observed at all times to prevent damage to existing road surfaces. Special arrangements would be made with the UDOT to transport oversize loads to the project area.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book") Chapter 4 & 5; BLM Notice to Lessees 3-A (NTL 3-A); BLM WO Instruction Memorandum 99-061 Onsite Bioremediation of Exploration and Production Wastes or Spills of Crude Oil – Development of State Office Level Policies	▪ Any accidental soil contamination by spills of petroleum products or other materials would be reported to the appropriate authorities and cleaned up by Newfield. The soil would be disposed of or remediated according to applicable rules. Spills of at least 10 barrels in non-sensitive areas would be reported to the BLM AO in a written report and other appropriate authorities. Major undesirable events of 100 barrels or more must be reported to the AO within a maximum of 24 hours; however, if the event is entirely contained within the facility firewall, it may be reported only in writing pursuant to Section III of NTL-3A. Any spill regardless of the volume involved, which occurs in a sensitive area, must be reported within 24 hours to the AO.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book") Chapters 4 and 5; WO-IM-2013-033 Fluid Minerals Operations – Reducing Preventable Causes of Direct Wildlife Mortality; U.S. Migratory Bird Treaty Act (16 USC 703-712)	▪ Pits would be fenced as specified in individual authorizations. Any pit containing hazardous fluids would be maintained in a manner that would prevent migratory bird mortality. ▪ After cessation of drilling and completion operations, any visible or measurable layer of oil must be removed from the surface of the reserve pit, and the pit must be kept free of oil. ▪ Pits must be free of oil and other liquid and solid wastes prior to filling. Pit liners must not be breached (cut) or filled (squeezed) while still containing fluids. The pit liner must be removed to the solids level or treated to prevent its reemergence to the surface or its interference with long-term successful revegetation. ▪ Closed-loop drilling would be used to protect natural water courses and groundwater from contamination.
BLM COA attached to approved Application for Permit to Drill (APD)	▪ If reserve pit leakage is detected, then discharge into the pit would cease as directed by the BLM until the leakage is corrected.
Utah Division of Water Rights (Utah Administrative Code, Title 73)	▪ All water used in association with this project would be obtained from sources approved by the Utah State Engineer's Office.
Regulations (40 CFR 335) implementing Title III, Superfund Amendments and Reauthorization Act of 1986 (SARA) (42 USC 103)	▪ Chemicals would be inventoried and reported by Newfield in accordance with SARA Title III. If quantities exceeding the threshold planning quantity are to be produced or stored at any time within the project area, Newfield would submit appropriate Section 311 and 312 forms at the required times to the State Emergency Response Commission, Local Emergency Planning Committees, and the local fire departments.
EPA Resource Conservation and Recovery Act of 1976 (42 USC 6901, et seq.), DOT (49 CFR 177)	▪ Newfield would transport and/or dispose of any hazardous wastes as defined by the EPA RCRA, as amended, in accordance with all applicable federal, state, and local regulations.

Implementing Authority/ Regulation/Statute	Description of Requirement
Completion	
BLM Onshore Oil and Gas Order No. 2 (43 CFR 3163 and 3165)	▪ Newfield would case and cement all oil and gas wells to protect subsurface mineral and usable water zones. The BLM will require an operator to conduct cement bond log surveys, or other tests to verify cement adequacy.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 6; and Onshore Oil and Gas Order No. 1 (43 CFR 3160)	▪ Wells that have completed their intended purpose would be properly abandoned and plugged according to regulations governing plugging and abandonment identified by the BLM and/or UDOGM for state and private mineral estate.
BLM COA for APD (for wells/reserve pits located on BLM lands), and UDOGM (Utah Administrative Code R649-3-16) (for wells/reserve pits located on state and private lands)	▪ Following drilling and completion of the well, produced water will be removed within 90 days from the reserve pit, which will be closed within 6 months (BLM) and recontoured within 180 days (UDOGM), unless permission is granted by the BLM and/or UDOGM for a longer period. The pit contents must meet the UDOGM's cleanup levels (Environmental Handbook, January 1996) or background levels prior to burial. The contents may require treatment to reduce mobility and/or toxicity to meet cleanup levels. The alternative to meeting cleanup levels would be transporting material to an approved disposal facility. BLM would generally defer to UDOGM's preference, which would be for materials to remain onsite if possible.
Production and Maintenance	
BLM Onshore Oil and Gas Order No. 7 (43 CFR 3160)	▪ Produced water from oil and gas operations would be disposed of in accordance with the requirements of Onshore Oil and Gas Order No. 7.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 6; and Onshore Oil and Gas Order No. 1 (43 CFR 3152)	▪ At producing wells, Newfield would reduce slopes to original contours (not to exceed 3:1 slopes where feasible). Areas not used for production purposes would be reclaimed, blended into the surrounding terrain, and reseeded, and installed with erosion control measures. These erosion control measures may be necessary after slope reduction. Mulching, erosion control measures, and fertilization may be necessary to achieve acceptable stabilization.
EPA SPCC Regulations (40 CFR 112)	▪ All storage tank batteries, treaters, dehydrators, and other production facilities that have the potential to leak or spill any oil, glycol, or other fluid that may constitute a hazard to public health or safety would be contained within the pad that would be surrounded by a berm along its entire perimeter. The berm would function as an appropriate containment and/or diversionary structure that would be constructed to help prevent discharges from a primary containment system from draining, infiltrating, or otherwise escaping to ground or surface waters prior to completion of cleanup.
BLM Notice to Lessees 3-A (NTL 3-A)	▪ Notice of any spill or leakage (as defined in the BLM Notice to Lessees (NTL) 3A) would be immediately reported to the AO by Newfield as well as appropriate other federal and state officials as required by law. Oral notice would be given as soon as possible, but within no more than 24 hours, and those oral notices would be confirmed in writing within 72 hours of any such occurrence.
EPA	▪ Newfield would obtain all necessary air quality permits from the EPA to construct and operate facilities.
Utah Department of Environmental Quality-Division of Air Quality (UDEQ/DAQ)	▪ Newfield would obtain all necessary air quality permits from UDEQ-DAQ to construct and operate facilities.

Implementing Authority/ Regulation/Statute	Description of Requirement
Final Reclamation and Abandonment	
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 6; Onshore Oil and Gas Order No. 1 (43 CFR 3160)	▪ Abandoned sites would be reclaimed in accordance with the approved APD and the Subsequent Report of Abandonment (sundry) process. Once successful reclamation has been achieved Newfield will submit a Final Abandonment Notice (FAN) for approval by the AO prior to bond release.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 3	▪ All disturbances would be managed and reclaimed to minimize runoff from the well pads or other facilities until the area is stabilized.
BLM/USFS Surface Operating Standards for Oil and Gas Exploration and Development ("Gold Book"), Chapter 6; Onshore Oil and Gas Order No. 1 (43 CFR 3160)	▪ All excavations and pits would be closed by backfilling and contouring to conform to surrounding terrain. The Surface Use Plan of Operations (SUPO) would outline objectives for successful reclamation of well pads and other facilities, including soil stabilization, plant community composition, and desired vegetation density and diversity.
Common to All Project Phases	
Section 7(a) of the Endangered Species Act of 1973 (ESA), as amended	▪ Section 7(a) of the ESA requires federal agencies to evaluate their actions with respect to any species that is proposed or listed as endangered or threatened, and with respect to its critical habitat, if any has been designated. Regulations implementing this interagency cooperation provision of the ESA are codified at 50 CFR 402. Section 7(a)(2) requires federal agencies to ensure that activities they authorize, fund, or carry out are not likely to jeopardize the continued existence of a federally listed species, or result in the adverse modification or destruction of its critical habitat. Section 7 Consultation would be conducted as necessary.
BLM Regulations (36 CFR 800) implementing Section 106, NHPA (16 USC 470, et seq.)	▪ Newfield would conduct all operations in conformance with Section 106 regulations (36 CFR 800) of the NHPA, as amended.
BLM Handbook (H-8270-1), General Procedural Guidance for Paleontological Resource Management	▪ Newfield would conduct all operations in conformance with BLM Handbook (H-8270-1).
BLM Handbook 9011-1, Exec Order 13112, Carlson-Foley 1968, and the Plant Protection Act of 2000, Public Law 106-224, and Fed Noxious Weed Act of 1974 as amended	▪ Newfield would obtain a Pesticide Use Proposal (PUP) prior to applying herbicides or pesticides. Newfield would treat project-related noxious weeds as required by all applicable regulations.
Clean Air Act (CAA), as amended, and the Federal Land Policy and Management Act (FLPMA)	▪ Newfield will conduct an annual emissions inventory and compare the inventory to the emissions estimates contained in this EIS. The inventory will be conducted annually for the life of the project (LOP) until the EPA/UDEQ/BLM develop an approved basin-wide control plan covering oil and gas development in the Uinta Basin. ▪ Regional photochemical modeling will be conducted that includes emissions for the selected alternative within one year of the ROD for this project or one year of the BLM Air Resources Management Strategy (ARMS) modeling platform becoming available, whichever occurs first. If modeled impacts show that the National Ambient Air Quality Standards (NAAQS) or applicable thresholds for air quality related values may be exceeded, BLM will require additional mitigation measures within BLM's authority to prevent exceedances (for example requiring Newfield

Implementing Authority/ Regulation/Statute	Description of Requirement
	to implement an ozone mitigation contingency plan as described below). ▪ As needed, the BLM, with input from UDAQ and EPA as appropriate, will refine the NOx and volatile organic compound (VOC) emissions inventory. The BLM, in coordination with UDEQ-DAQ and EPA as appropriate, will ensure that new modeling includes feasible best available control technology (BACT) requirements and a sensitivity analysis to determine appropriate reductions in ozone precursor emissions. The BLM, in coordination with UDEQ-DAQ and EPA as appropriate, will evaluate the modeling results. ▪ As soon as possible, and if needed following evaluation of the modeling results, the BLM, in coordination with UDEQ-DAQ and EPA as appropriate, will use their respective authorities to implement emission control strategies and/or operating limitations necessary to ensure compliance with applicable ambient air quality standards for ozone. Absent an effective technology to implement, reductions in the pace of development may be used to ensure ambient air quality standards are met. ▪ Newfield would implement project-specific enhanced mitigation measures to address winter ozone formation that includes the following: o FLIR/AVO inspections of pneumatic devices, pumps, tanks, and fugitives at least annually during January to March. o Perform regular maintenance on emitting devices and properly operate and maintain existing installed control equipment o Provide ozone training for operations personnel prior to the ozone season. o Implement work practices during the winter ozone period to reduce potential emissions, including charging desiccant dehydration units prior to the winter ozone period, reducing glycol dehydration circulation rates, minimizing blow down actions, reducing the number of failed compressor startups, reducing compressor startups by performing maintenance during scheduled shutdowns, delaying optional activities that could cause emissions, and taking extra care to ensure maintenance and operation of equipment during winter ozone alert days. o The BLM may add, delete, or otherwise modify the enhanced mitigation measures to conform to the requirements or recommendations of a regulatory basin-wide management plan. ▪ The BLM will work with the appropriate regulatory agency to ensure monitoring and enforcement of mitigation measures occurs.
BLM MOU WO-230-2010-04, MOU between the BLM and the USFWS to Promote the Conservation of Migratory Birds	▪ BLM shall implement the MOU to the extent permitted by law and in harmony with agency missions, subject to the availability of appropriations and budgetary limits. At the project level, BLM will evaluate the effects of agency actions on migratory birds during the NEPA process, if any, and identify where take reasonably attributable to agency actions may have a measurable, negative effect on migratory bird populations, focusing first on species of concern, priority habitats, and key risk factors. In such situations, BLM will implement approaches lessening such take.

2.2 DEVELOPMENT ACTIVITIES COMMON TO ALL ACTION ALTERNATIVES

Newfield is proposing to expand their ongoing oil and natural gas development and secondary recovery within the MBPA using waterflood methods and deep gas operations. Waterflood methods involve the injection of produced water and freshwater (through formerly producing or new wells) into the oil-producing geologic formation. Nearby actively producing wells extract the fluids through the formation as the water displaces the oil. In addition, portions of the MBPA along the northwest and southern Project boundaries would be subject to expansion away from existing development.

Newfield proposes to drill new wells as infill to all productive formations, including but not limited to, the middle and lower members of the Green River formation and upper member of the Colton Formation. The Green River oil wells would be drilled to a total depth of between 4,500 and 6,500 feet below ground surface (bgs), and the proposed deep gas wells would be drilled to a total depth of between 13,000 and 18,000 feet bgs.

Alternative maps (see **Figures 2-1** through **2-4 – Attachment 1**) indicate conceptual locations of potential well pads from which oil and natural gas resources could be developed. Per comments received by the BLM from the State of Utah, a Cooperating Agency on this EIS, the State assumes that Newfield would assume full recovery of State mineral resources under any of the alternatives. The extent of such development and prospective nature of the resources is based on three-dimensional (3D) seismic data, geologic information, data derived from wells drilled to date, and economic factors.

Well density in the MBPA would vary based on geologic characteristics of the formation being targeted for development. The range of downhole well densities expected at this time is one well per 20 acres (i.e., middle member of the Green River Formation) to one well per 40 acres (i.e., middle and lower members of the Green River Formation). The ultimate number and density of wells would be defined through future drilling and would vary by alternative. Newfield would use directional drilling and multiple well pad drilling techniques to develop these resources in a manner that would limit the number of well pads or surface locations (i.e., surface density) to a maximum of one well pad per 40 acres.

The number of wells per well pad would vary based on downhole spacing, technical feasibility, and the geologic characteristics of the targeted formation. Some well pad locations would host a single well and others may have multiple wells drilled from a single well pad.

Figure 2.6-1 shows the existing high- and low-density development areas within the MBPA. High-density development areas are those areas that have from 6- to 16-well pads per 640-acre section (i.e., one well pad per 40 to 106 acres). Low-density development areas are defined as those areas that have had no gas development at all or contain up to five well pads per section.

Of the 197 sections (or portions of sections) within the MBPA, 115 sections (or portions of sections [about 58 percent]) are within the high-density development areas. Average existing surface disturbance within the high-density development areas is 39.0 acres per section and the average number of well pads per section is 14.3. Approximately 82 sections (or portions of sections) occur within the low-density development areas. The average existing disturbance within the low-density development areas is 11.9 acres per section and the average number of existing well pads per section is 2.8.

The life cycle of an individual well and its associated facilities/required infrastructure (e.g., roads, pipelines, and compressor stations) is composed of seven primary phases: (1) preconstruction, (2) construction, (3) drilling, (4) completion, (5) interim reclamation, (6) production and maintenance, and (7) final reclamation and abandonment. Specific details of these seven primary phases that are common to all action alternatives are described in the following sections.

2.2.1 Preconstruction Activities

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

Prior to the start of construction activities on BLM-managed lands, Newfield would initiate the well-permitting process by filing either a NOS or an APD with the BLM VFO, which would start the application process to ensure that it meets applicable requirements. For wells on split estate lands, Newfield 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 SUPO, Drilling Plan, evidence of bond coverage, shapefiles, and other information required to comply with *Onshore Oil and Gas Order No. 1*. A SUPO 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 Newfield's design, construction techniques, and procedures would be made by the appropriate AO during the initial permitting process. This Federal Oil and Gas Onshore Order applies to federal minerals.

2.2.1.2 On-Site Inspection and Construction Initiation

Prior to APD approval and construction, SMA personnel would conduct on-site inspections to assess potential impacts and recommend additional methods to mitigate impacts. The SMA may impose COAs to the APD based on site-specific analysis and the NEPA process. These additional environmental protection measures would cover all aspects of oil and gas development, including construction, drilling, production, reclamation, and abandonment. The SMA would arrange a date, time, and place to meet with Newfield to perform an on-site inspection. Survey stakes, with cut and fill footages, 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 leases, 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 650 feet and a subsequent delay in operations of up to 60 days.

2.2.2 Proposed Construction Activities

2.2.2.1 Well Pads

Prior to well pad construction or surface disturbing activities, Newfield would obtain approval of an APD by the BLM AO. The APD would contain site-specific COAs that would apply to construction and well operations. Construction of well pads would typically begin with stripping and stockpiling topsoil. The top 4 to 6 inches of topsoil material (preferably all topsoil) would be stockpiled for use in interim reclamation.

Following topsoil removal and stockpiling, each well pad would be constructed using standard cut-and-fill techniques to create a level pad needed for drilling operations. With associated cut and fill slopes, single Green River oil wells with a 40-acre surface density would be constructed to average dimensions of approximately 225 x 400 feet (2 acres in size), while vertical deep gas wells with a 40-acre surface density would be constructed to average dimensions of approximately 275 x 475 feet (3 acres in size). Well pads hosting multiple wells and/or horizontal wells would be approximately 0.2 acres larger than the 2 to 3-acre average.

Primary surface equipment to be installed at each well pad would include a drilling rig, reserve pit or closed-loop system, mud tank, dog house flare pit, pipe racks, pump house, trailers, water storage tanks, and generators. The typical layout for a single well pad is illustrated in **Figure 2.2.2.1-1 (Attachment 1)**.

Fill slopes, where necessary, would be compacted and maintained to maximize slope stability and minimize erosion. Where cut and fill slopes are required, they would be constructed at no steeper than a 3:1 ratio. Engineering design would ensure that cut and fill volumes of soils would generally be balanced to ensure all materials generated during construction are used to the greatest extent practicable, and that few or no spoil piles remain.

Once the pad has been leveled and graded, it would be compacted to establish a level and solid foundation for the drilling rig. The site preparation process would take approximately 3 to 4 days to complete. The well pad would be constructed to prevent surface run-on by channeling flow within diversion ditches and energy dissipaters (if needed) around the site and then released to grade, consistent with Best Management Practices (BMPs) for erosion control.

2.2.2.2 Reserve Pits and Flare Pits

The reserve pit would be constructed on the well pad for the containment and temporary storage of drill cuttings and drilling mud for no more than 90 days (43 CFR 3160.7). The reserve pit would be sized appropriately depending upon the number and type of wells that would be drilled from the individual well pad. The largest proposed reserve pit would be approximately 185-feet long, by 100-feet wide, by 8-foot deep and would hold approximately 830,338 gallons. All reserve pits would be designed to maintain a two-foot freeboard[1].

Where possible, reserve pits would not be constructed in fill material. Where cut material locations are not possible, or where sensitive areas exist, a closed-loop system, with above ground tanks in lieu of a pit, would be considered at the discretion of the AO. The reserve pit would be constructed by mechanical compaction and lined to prevent loss of drilling water. The pits would be lined with a reinforced polyethylene liner a minimum of 16 mil thickness, with sufficient bedding used to cover any rocks. The liner would overlap the pit walls and be anchored with dirt and/or gravel to hold it in place. The reserve pit would be constructed and operated in accordance with UDOGM rule R649-3-16–*Reserve Pits and Other On-site Pits* and in accordance with *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* (BLM 2007a). This publication will be referenced hereafter as the *Gold*

[1] Freeboard is the vertical distance between the normal maximum level of the water surface in a channel, reservoir, tank, canal, etc., and the top of the sides of a levee, dam, etc., which is provided so that waves and other movements of the liquid will not overtop the confining structure.

Book. The *Gold Book* provides practices and standards to guide compliance with applicable agency policy, operating guidelines, and BMPs. The reserve pit would be fenced on three sides during drilling to prevent wildlife or livestock from entering the pit. Once drilling is complete all sides will be fenced. Recontouring would be completed within 180 days.

2.2.2.3 Access Roads

A network of roads already exists within the MBPA. These roads would be used as is or upgraded where needed to access well pads or other surface facilities. New roads would be constructed only where necessary, because they have been sited and designed to minimize disturbances and maximize transportation efficiency. 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.

All access roads would be constructed out of native material and to the standards outlined in the *Gold Book*. Following staking of the road corridor and on-site review, the road design plan would be approved and any engineering needs specified. After road approval, standard cut and fill construction methods and construction equipment would be used to construct new roads. A typical roadway cross-section with width specifications is shown in **Figure 2.2.2.3-1 – Attachment 1**.

All roads would be constructed with appropriate drainage and erosion control features (e.g., cut and fill slope and drainage ditch stabilization, relief and drainage culverts, wing ditches, and rip-rap). Where needed, road base or gravel would be placed on upgraded and newly-constructed roads to provide a stable travel-way surface. Aggregate for road surfacing would be obtained from existing, permitted quarries from permitted sources. Aggregate would be of sufficient size, type, and amount to allow all weather access and to help minimize fugitive dust.

In steep terrain, a construction technique known as side casting (using the material taken from the cut portion of the road to construct the fill portion) would be used. Slightly less than half of the roadbed would be placed on a cut area; the remainder would be placed on a fill area. Soil texture, steep road grades, and moisture conditions would dictate whether the access road would be surfaced with commercial road base or shale. Water or other approved surfactants, such as magnesium carbonate, would be used to control dust during construction.

All necessary county planning and zoning permits would be secured prior to road construction, and maintenance agreements would be signed with the counties where Class B and Class D county roads would be used for daily operations in the MBPA. These agreements would include provisions for the maintenance and upkeep of county roads by Newfield to enhance their functional use and safety. All roads would meet minimum *Gold Book* and BLM Manual 9113 standards for construction.

The number of pipelines and utilities required, and the spacing between pipelines, utilities, and roads required for safe operations, would define the necessary corridor width. Where new co-located roads and pipeline/utility line ROWs are proposed, an initial disturbance corridor up to 100 feet in width would be needed for construction purposes. Of the initial 100-foot wide corridor, a 40-foot width would be used for road construction, and 30-foot width corridors on each side of the road would be used for the installation of pipelines and utility lines (see **Section 2.2.2.4**). One side of the road will be used for both buried and surface lines where possible, and both sides of the road will be used as necessary based on existing infrastructure or topography. Typically, a buried pipeline is installed directly adjacent to the road and in bar ditch that is 10 to 15 feet wide. The 30-foot wide corridor is allowed for construction and does not reflect the entire width of disturbance in the ROW.

Existing road ROWs would require an expansion width of approximately 70 feet; 10 feet of which would be needed for general road improvements (i.e., recontouring, borrow ditches, and stormwater management), and the remaining 60 feet would be used for the installation of pipelines and utility lines. Following reclamation, a 10-foot width would remain for the long-term road ROW in addition to the existing road width, and a 25-foot width would remain for the long-term pipeline/utility line ROW. A typical roadway cross-section with pipeline installation alongside the road is shown in **Figure 2.2.2.3-2 – Attachment 1**.

Construction of new roads or upgrading of existing roads would typically take 1 to 2 days per mile of road. Primary access roads/trunk roads (i.e., those providing access through the MBPA or to multiple well pads) or roads constructed or upgraded in steep terrain would require more time to complete; that is, approximately 2 to 3 days per mile of road. Spur roads to individual well pads would be constructed immediately prior to well pad construction. For trunk roads, several crews could operate simultaneously on different roads or different portions of the same road. Total personnel working on trunk road construction or improvements could range in size from 10 to 25 individuals. Each spur road workforce would include an average of five personnel to operate the equipment.

2.2.2.4 Pipelines

The existing pipeline gathering system within the MBPA would be expanded as development progresses. Proposed pipelines for new development would be integrated into the existing pipeline network within the MBPA. These include gas and liquid gathering pipelines, water injection pipelines, produced water pipelines, and fuel lines. Water distribution lines, injection lines, and high pressure gas pipelines would be buried, while oil gathering lines, low pressure gas lines, and fuel lines would be installed on the ground surface.

Pipeline expansion would typically be accomplished by looping or paralleling existing lines with additional lines and by adding compressors within the existing and planned facilities. A loop pipeline is defined as a pipeline that is constructed near an existing pipeline, which is placed in service concurrently for the purpose of adding additional capacity to the existing system.

All high pressure gas lines would be buried unless constrained due to topography or surface geology. All low pressure gas lines would be placed on the surface. New gas gathering lines would be constructed of steel pipes from 4 to 10-inches in outer diameter. Each gathering line would tie into a larger 10 to 16-inch outer diameter trunk line that would eventually transport the gas to compression facilities located in or near the MBPA. Typical pipeline installation scenarios with width specifications are shown in **Figure 2.2.2.3-2** and **Figure 2.2.2.4-1 – Attachment 1**.

Water pipelines would be needed to transport produced water to the water treatment facilities and transport fresh and recycled water to the injection wells for waterflood purposes. Water pipelines would be from 4 to 8-inches in diameter and constructed from steel and/or polypropylene. These water pipelines would be buried to prevent freezing and would be installed in conjunction with (alongside) the high pressure gas gathering pipelines, where possible.

Surface gathering lines would be buried where they intersect with access roads. Each pipeline ROW could include multiple gas gathering pipelines (both low and high pressure systems with potential loop lines), fuel gas pipelines, oil gathering pipelines, as well as produced water and water injection pipelines.

This would initially involve widening the disturbance corridor along the existing roadway by approximately 60 feet to accommodate the proposed gas gathering pipelines and water pipelines. Following pipeline installation approximately 35 feet (or more if buried) of the pipeline ROW width could be reclaimed, leaving a 25-foot width for the long-term pipeline/utility line ROW[2].

In limited situations (for example, to reduce total pipeline length), a proposed pipeline ROW would be installed independent of an access road. Pipelines installed independent of roads (e.g., cross-country pipelines, or water pipelines for the water collector well) is anticipated for fewer than 10 percent of all pipelines under any of the alternatives.

The decision to bury a cross-country pipeline versus laying it on the surface would depend upon the alternative selected, soil conditions, terrain, and product being piped. New cross-country pipelines would require a 40 to 50-foot-wide construction ROW depending on whether they are laid in the surface or buried. The exact location of pipelines would be determined at the time of the on-site inspection with the appropriate SMA. As conceptual locations for cross-country pipelines are not yet known, they are not reflected in the alternative-specific maps. A rough estimate of disturbance from cross-country pipelines is included in the narrative description of each alternative but is not reflected in the GIS-based surface disturbance tables or the resource-specific surface disturbance calculations in Chapter 4.

Generally pipeline construction would occur in a planned sequence of operations along or within road ROWs. For buried pipelines, the pipeline trench would be first cleared of vegetation by blading the surface only if necessary to stabilize equipment. The pipeline trench would then be excavated mechanically with either a trencher or backhoe to a depth of approximately 36 inches. The width of the trench would range from approximately 18 to 36-inches depending on the number of co-located pipelines and the diameter of pipe placed in the trench bottom. Pipe laying activities would include pipe stringing, bending, welding, coating, lowering of pipeline sections into the trench, and backfilling. Surface pipelines adjacent to roads would be assembled on the roadway or construction ROW, lifted, and placed in the existing vegetation using a side-boom.

Each gathering pipeline would be tested with pressurized fresh water or air to locate any potential leaks. Fresh water used for hydrostatic testing would be obtained from existing, permitted water supply sources (see **Table 2.2.8-1**). These sources would consist of both ground water from wells, surface withdrawals from permitted sources, and from Newfield's proposed water collector well along the Green River. Withdrawals would be made from suppliers that hold existing water rights permits through the Utah Division of Water Rights. After completion of hydrostatic testing, waste water would be taken to Newfield's water injection facility, where it would be treated and reused for waterflood purposes.

2.2.2.5 Compressor Stations

Newfield would expand up to three existing compressor stations and construct up to 21 new compressor stations to accommodate oil and gas production in the MBPA, depending on which alternative is selected. Expansion plans for the existing compressor stations would include the installation of additional compressor units or replacing smaller capacity units with larger ones. Each new compressor would be built with up to 8,000-horse power (hp) of compression. Compressor station locations would be

[2] The term ROW is used throughout this document to describe access road, pipeline, and utility line corridors, even though a true BLM ROW may not be required.

constructed similar to well pads as described in **Section 2.2.2.1**. Each site would be constructed to approximately 730 x 600 feet (10 acres in size).

Associated equipment to be installed at each compressor station would include an inlet separator (unfired); a 50 million standard cubic feet per day (MMscf/d) dehydrator; four 400-bbl atmospheric production tanks; one flare (used for emergency relief); one vapor control unit used to control stock tank and dehydrator emissions; and dew point control equipment with a pressurized NGL storage bullet and associated truck loading rack. A typical layout for a compression station is shown in **Figure 2.2.2.5-1 – Attachment 1**.

Existing compressor stations for the Green River wells within the MBPA would be expanded by approximately 5 acres each to accommodate additional facilities, which would include up to 5,000 hp of additional compression. The expanded compressor stations would occupy approximately 10 acres and include up to 8,000 hp of compression. Primary equipment to be installed at each expanded compressor station would include an inlet scrubber; one 50-MMscf/d dehydrator; four 400-bbl atmospheric production tanks; an emergency flare and a vapor control unit; and one gas conditioning refrigeration unit with a pressurized NGL storage bullet and associated truck loading rack.

2.2.2.6 Central Gas Processing Plant

Following compression, gas would be transported by a 10-inch gas gathering line to one proposed centralized gas processing plant that would be constructed to process up to 50 MMscf/d. The conceptual location for the proposed gas processing plant is presented on **Figures 2-1** through **2-4 – Attachment 1**. Construction of the proposed gas processing plant would be essentially the same as that previously described for the well pad and compressor station sites (see **Section 2.2.2.1**).

The processing plant would occupy an approximate 10-acre site. Primary surface equipment to be installed would include four 300-hp compressors; one flare; one vapor control unit; one 50-MMscf/d dehydrator; and one load out rack.

2.2.2.7 Water Treatment and Injection Facilities

Newfield would construct up to seven new and expand six existing water treatment and injection facilities within the MBPA. The proposed water treatment facilities would be used for recycling of produced water that would either be co-mingled with fresh water and piped for waterflood injection wells, or trucked from the facility to be used at subsequent wells for completion activities.

Construction of the proposed water treatment and injection facilities would be essentially the same as previously described for the well pad and compressor station sites (see **Section 2.2.2.1**). New water treatment and injection facilities would occupy an approximate 8 acre site. Existing treatment and injection facilities would be expanded by approximately 5 acres. Equipment at each facility would include four 500-hp main injection pumps; four 125-hp auxiliary injection pumps; up to six 500-bbl oil tanks; up to 10 500-bbl inlet water tanks; six to eight 5,000-bbl water storage tanks; one vapor control unit; and a natural gas fueled generator for pumping.

Each treatment and injection facility would be connected to nearby proposed injection wells by a series of buried water injection pipelines. Water intended for dust suppression or re-use in drilling or completion activities would be trucked from the injection facilities to drilling locations. Produced water not suitable for waterflood purposes or dust suppression would be trucked from treatment and injection facilities to permitted disposal wells within the MBPA.

2.2.2.8 Gas and Oil Separation Plants (GOSPs)

Depending on the alternative selected, Newfield would construct and operate up to 12 (i.e., one existing and 11 proposed/approved Gas and Oil Separation Plants [GOSPs]). GOSPs would be used for the initial separation of produced water and gas from the oil prior to shipment for refining. Construction of the GOSPs would be essentially the same as that previously described for the well pad and compressor station sites (see **Section 2.2.2.1**). Each GOSP would occupy approximately 22 acres.

Surface facilities at each GOSP would consist of the following:

- Eight electric motor driven 200-hp pumps
- Up to seven free water knock outs (FWKOs)
- Up to three heater treaters
- Up to four 5,000-bbl oil tanks; One (1) 5,000-bbl water tank
- One emergency flare
- Two vapor combustion units (VCUs)
- Tanker truck oil load out racks
- Three 11-million British Thermal Units (MMBtu)/hr natural gas fueled process heaters
- One primary and one (1) backup 1,400 kW generators driven by gas fueled engines
- Two pipeline pig receivers

Produced fluids consisting of black wax hydrocarbons, produced water and entrained natural gas gathered from wells in the MBPA would be delivered by pipeline to the GOSPs. The design process rate for each GOSP facility would be 10,000 barrels per day (bbls/day), consisting of approximately 5,000 bbls/day of oil and 5,000 bbls/day of produced water. As the MBPA field oil production rate continues to decline, the ratio of oil to produced water, and the oil related volatile organic compound (VOC) emissions, would decrease over time. A typical layout for a GOSP is shown in **Figure 2.2.2.8-1 – Attachment 1**.

Each GOSP would be designed to minimize VOC emissions by eliminating hydrocarbon emission sources when possible, recycling hydrocarbon gas streams when feasible, and destroying excess hydrocarbons when necessary. The gas collected from the FWKOs and heater treaters would be captured and compressed for reuse or sale. The produced gas compressors would be driven by electric 200-hp motors. The captured produced gas would be recycled and used for fuel at each GOSP. Fuel would be treated by a sulfur removal tower prior to use. The sulfur removal tower is a closed unit and under normal operations would have no emissions.

Fuel gas from the MBPA system would normally augment the fuel gas supply at each GOSP. When produced gas volumes exceed the needed fuel at a GOSP, the excess gas would be routed to the existing wet gas gathering system for treatment and compression prior to sale.

2.2.2.9 Pump Stations

Newfield would construct up to six water pump stations to boost pressure to ensure consistent delivery of fresh and produced water to water treatment and injection facilities. Construction of pump stations would be essentially the same as that previously described for the well pad and compressor station sites (see **Section 2.2.2.1**). Pump stations would occupy approximately 3 acres. Pump station facilities would include one 200-hp water pump and up to two 400-bbl water storage tanks.

2.2.3 Well Drilling

Drilling operations would be conducted in two (2) phases. A small conventional drilling rig (similar to a water well rig) would drill to a depth of approximately 600- to 1,000-feet or 50 feet below any usable water encountered. Water that is defined as "usable" has less than or equal to 10,000 mg/L total dissolved solids. Federal Safe Drinking Water Act regulations define an Underground Source of Drinking Water (USDW) as an aquifer or portion thereof: (a)(1) which supplies any public water system; or (2) which contains a sufficient quantity of ground water to supply a public water system; and (i) currently supplies drinking water for human consumption; or (ii) contains fewer than 10,000 mg/l total dissolved solids; and (b) which is not an exempted aquifer (See 40 CFR Section 144.3). The annular space between the borehole and the surface casing for the entire length of the surface casing would be sealed with cement to isolate any USDWs encountered near the surface. As the borehole is dug, the drilling mud between the casing and the borehole prevents migration of oil and gas to USDWs. When the well is cemented, the cement is inserted at the bottom of the hole under pressure, and as it rises, it forces the drilling mud up and out of the borehole. Using this procedure, there is never an open hole for oil or gas to migrate to USDWs. A cement bond log will be run to ensure that the seal is adequate. This part of the drilling operation would normally take 2 to 3 days to complete.

Upon completion of drilling the surface hole, a larger industry standard rotary drill would drill to the total target depth. Drilling operations would include: adding new joints of pipe at the surface as the hole deepens; circulating drilling mud to cool the drill bit and remove the cuttings; removing the drill string from the hole to replace worn drill bits; and setting production casing and cementing it in place. The annular space between the borehole and the production casing for the entire length of the production surface casing would be sealed with cement to isolate any USDWs encountered at depth with the method previously described. Green River oil wells would be drilled to a total depth of between 4,500 and 6,500 feet bgs, and the proposed deep gas wells would be drilled to a total depth of between 13,000 and 18,000 feet bgs depending on the target formation.

Prior to drilling below the surface casing, a blow-out preventer (BOP) would be installed on the surface casing, and both the BOP and surface casing would be tested for pressure integrity. The BOP and related equipment would meet the minimum requirements of *Onshore Oil and Gas Order No. 2*. The BLM would be notified in advance of all pressure tests in order to witness those tests, if so desired.

The drilling contractor may run a downhole mud motor to increase the penetration rate. The rig would pump fresh water as a circulating fluid to drive the mud motor, cool the drill bit, and remove cuttings from the wellbore. In order to achieve borehole stability and minimize possible damage to the hydrocarbon producing formations, a potassium chloride substitute and commercial clay stabilizer may be added to the drilling fluid. In addition, 10 to 20 gallons of polyacrylamide polymer (PHPA) per 1,000-bbls could be added to the drilling fluid to provide adequate viscosity to carry the drill cuttings out of the wellbore. From time to time other materials may be added to the fluid system, such as sawdust, natural fibers, or paper flakes, to reduce downhole fluid losses. In addition, with deeper wells, barite weighting material may need to be added to the mud system to control formation pressures and provide borehole stability.

Upon drilling each well to an intermediate depth, a series of logging tools would be run in the well to evaluate the potential hydrocarbon resource. Steel production casing would then be run and cemented in place from surface to an intermediate depth in accordance with the well design, and as approved by the BLM in the APD and any applicable COAs. The casing and cementing program would be designed to isolate and protect USDW formations encountered in the wellbore, to prohibit pressure communication or fluid migration between zones by using the resource protection guidance outlined in *Onshore Oil and Gas*

Order No. 2 and UT IM 2010-055, and to provide a structural platform to attach well control equipment. The types of casing used, and the depths to which they are set, would depend upon the physical characteristics of the formations that are drilled and would be specified in the APD for each well. All casing would be new or inspected previously used casing. Where necessary, intermediate and/or production casing would subsequently be run to total depth. The BOP equipment would be re-tested prior to drilling the final section of the well below the intermediate casing point.

Following the completion of drilling operations and prior to running the casing to total depth, open hole well logs may be run to evaluate a well's production potential. If the evaluation concludes that adequate hydrocarbon resources are present and recoverable, then steel production casing would be run to total depth and cemented in place in accordance with the well design, and as approved by the BLM. The casing and cementing program would be designed to isolate and protect the formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals encountered in the wellbore and to prohibit pressure communication or fluid migration between zones.

Drilling operations would occur on a 24-hour per day basis. Drilling activities would take approximately 5 days for a vertical or a directional Green River oil well, 21 days for a horizontal Green River oil well, and approximately 55 days for a vertical deep gas well. Drilling activities would require approximately 12 personnel per well. An average of 360 wells would be drilled per year, therefore, up to eight drill rigs (i.e., four Green River oil rigs and four deep gas rigs) could be in the MBPA at any given time.

Drilling would be conducted in compliance with all Federal Rules and Regulations, including Federal Oil and Gas Onshore Orders, all State UDOGM rules and regulations, and all applicable local rules and regulations. Site-specific descriptions of drilling procedures would be included in the APD and additional regulatory measures may be specified in the COAs for each well. Information relative to size of the bore hole (usually 5 to 24 inches), casing, and cementing would also be contained in the site-specific APDs.

In the event it becomes necessary to flare a well, flare lines would be directed to flare pits to avoid environmental damage and as required by regulations. A deflector and/or directional orifice would be used to safeguard project personnel and other natural resources.

An example well bore diagram is provided in **Figure 2.2.3-1 (Attachment 1)**.

2.2.4 Well Completion

After a well is drilled and production casing is set, a completion unit would be moved 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 fracture stimulation is required on the majority of wells in the MBPA to enhance productivity. All hydraulic fracturing activity would be in compliance with BLM and UDOGM hydraulic fracturing rules and notices. Water/sand slurry would be used with gels and other non-toxic chemical additives to ensure the quality of the fracture fluid. Fluid would be pumped down the well through perforations in the casing and into the formation. Pumping pressures would be increased to the point at which fractures occur in the rock formations and radiate outward from the perforations into the target formation. The slurry that flows rapidly into the fractures and the sand in the slurry mix would serve as a proppant to keep the created fracture open after the fracture treatment, thereby allowing reservoir fluids to move more readily into the well. Water use during drilling and completion operations would vary in accordance with the characteristics of the formations the wells are completed in, but would average approximately 7,000 bbls (0.9 acre-feet) for a Green River oil well and up to 48,000 bbls (6.2 acre-feet) for deep gas well.

Typical equipment and vehicles used during completion activities would include carbon dioxide (CO_2) tanker trucks; sand transport trucks; water trucks; oil service trucks used to transport pumps and equipment for fracs; flat beds and gin pole trucks to move water tanks, rigs, tubing, and frac chemicals; logging trucks (cased hole wireline trucks); and pickup trucks to haul personnel and miscellaneous materials and equipment.

Completion activities would take place on a 24-hour basis, requiring approximately 14 workers. Green River oil well completions would take an average of 6 to 7 days for vertical or directionally drilled Green River wells. Horizontal well completions would take up to 10 days to complete. Completion activities on the deep gas wells would require an average of 24 days depending on the number of completion zones. If flaring is necessary during completion operations, flaring would take place as described in **Section 2.2.3**.

2.2.5 Interim Reclamation

Interim reclamation consists of minimizing the footprint of disturbance by reclaiming all portions of well pads, ROWs, and other surface facilities not needed for production operations. The portions of the well site and other project facilities that are not needed for operational and safety purposes would be recontoured to a final or intermediate contour that blends with the surrounding topography as much as possible. Stockpiled topsoil would be re-spread over areas not needed for all-weather operations. When practical, topsoil would be re-spread over the entire location, roughened to enhance water catchment and revegetated to within a few feet of the production facilities; unless an all-weather surfaced access route or turnaround is needed.

Some locations would require special reclamation practices. Methods such as hydromulching, straw mat application on steeper slopes, fertilizing, and soil analysis to determine the need for fertilizer, seed-bed preparation, contour furrowing, watering, terracing, water barring, and the replacement of topsoil would be implemented as directed by the SMA. Interim reclamation surface disturbance associated with the proposed project and alternatives would be implemented in accordance with the *Green River District Reclamation Guidelines for Reclamation Plans* (BLM 2011a). These guidelines would apply to interim reclamation activities in the MBPA and include measurable standards as well as the monitoring and reporting of compliance with the reclamation standards. The Green River District has developed a web-based reclamation database entitled the “Green River Database Management System”. This system allows operators or contractors to submit reclamation reports. Reclamation reports associated with this Project will be submitted via this database.

Prior to interim reclamation activities, all solid wastes and refuse would be removed and transported to an approved landfill. Upon completion of a producing well site, all reserve pits, cellars, rat holes, and other bore holes unnecessary for further well operations would be promptly backfilled. Reserve pit closure would be subject to COAs determined through the APD process. Any hydrocarbons in the reserve pit would be removed and processed or disposed of at an appropriate offsite commercial facility. Cuttings generated during the drilling process would be buried in the reserve pit following the evaporation or removal of free liquids. The reserve pits would be drained and emptied of fluids within 90 days and closed within 6 months of well completion as per the requirements of *Onshore Oil and Gas Orders No. 7*, subject to weather conditions. The pit liner would be folded into the reserve pit and the pit backfilled. Backfilling of each reserve pit would be done in such a manner that the mud and associated solids would be confined to each pit and not incorporated in the surface materials. The reserve pit and that portion of the location not needed for production facilities/operations would be recontoured to the approximate natural contours and crowned slightly to prevent water from standing. All of the topsoil would be spread over the recontoured area and then seeded to promote topsoil viability. All disturbed areas would be reclaimed with a seed mixture of pure live seed (PLS) accepted and approved by the AO.

2.2.6 Production, Operation, Hydraulic Fracturing, and Maintenance Activities

2.2.6.1 Production and Operations

Production facilities would be installed on the well pad when a well is determined to be commercially productive. Newfield may eventually employ the use of centralized tank batteries (CTBs) as multiple wells are brought into production within a given area. Each CTB would centralize the location of the production equipment for multiple wells, thereby reducing surface facilities on individual pads. As CTBs are constructed and become operational, daily well maintenance traffic would be reduced. The number of and locations of potential CTBs would be highly dependent upon the surrounding topography and proximity to the wells contemplated for inclusion at the individual CTB. In some cases, a stand-alone tank would be necessary. For the purposes of analysis, it is assumed that all CTBs would be located on proposed GOSPs.

Permanent above-ground structures, including pumping units, would be painted a flat, non-reflective, earth-tone color on the BLM's Standard Environmental Color Chart, as determined by the AO. Facilities would be painted within 6 months of installation. As required by the Occupational Safety and Health Administration (OSHA), some equipment would not be painted for safety considerations (i.e., some parts of equipment would retain safety coloration).

2.2.6.1.1 Green River Oil Wells

Primary production equipment at the Green River oil wells would include the wellhead; a pumpjack driven by a natural gas fueled engine; a heater treater to separate oil, gas, and water; two 400-bbl oil/production tanks; and one 200-bbl produced water tank. Ancillary equipment on each of the well pads may include 150-gallon chemical storage drums, 55-gallon motor oil drums, and 55-gallon methanol storage drums.

As the GOSP system is phased in, Newfield would remove tanks and heater treaters from individual well pads that are served by a GOSP. The heater treaters would be replaced by a separator. As GOSPs are phased in, the well facilities would be reduced/eliminated resulting in a decrease in pumper truck traffic. Maintenance activities would be re-directed to the GOSPs.

During daily operation of the Green River oil wells, produced oil and water from the wells may potentially be transported via surface pipeline to one of the existing or proposed GOSPs located within the MBPA. The oil and produced water would be separated at the GOSPs and routed to separate storage tanks. Oil would be sold directly from the GOSPs and transported to commercial points outside of the MBPA by tanker truck. Well site storage tanks, a VOC emissions source, and related tanker truck traffic would be eliminated at wells served by a GOSP.

Produced water from the Green River oil wells would be transported by pipeline to one of the proposed water treatment and injection facilities. Produced water not suitable for reinjection would be trucked to permitted salt water disposal (SWD) wells for disposal.

Crude oil produced from the Green River reservoir sands in the MBPA is known to be high in paraffin content, with a pour point of 95 degrees Fahrenheit (°F) below which the oil solidifies. Consequently, flowlines and production tanks would be equipped with a closed-loop trace system that circulates heated ethylene glycol solution (antifreeze) to maintain crude oil in a fluid state.

2.2.6.1.2 Deep Gas Wells

Production equipment at deep gas wells would include a wellhead; one 400-bbl condensate/production tank; one 400-bbl produced water tank; storage tanks for methanol and motor oil; a gas meter; and a combination unit 2.0-MMscf/d separator and dehydrator, with an integral boiler (estimated at 750 thousand British Thermal Units (MBtu)/hr). Ancillary equipment on each of the well pads may include 150-gallon chemical storage drums.

Gathered natural gas produced from the deep gas wells would be flared for up to 30 days after initial well evaluation tests. If flaring is to exceed 30 days, Newfield would request approval from the appropriate regulatory authority (i.e., UDOGM or EPA). Following testing and during daily operation of the gas wells, gas from an individual well would first be separated from associated condensate and water at the well pad and then piped to one of the proposed or existing compressor stations. Once the produced gas is compressed and dehydrated at the proposed compressor stations, it would be carried via pipeline to the central gas processing plant where it would be prepared for delivery to a sales pipeline. Condensate from the deep gas wells would be sold and transported to commercial points outside of the MBPA by tanker truck. Produced water from the deep gas wells would be transported by pipeline to one of the proposed water treatment and injection facilities where it would be treated and used in the Green River secondary oil recovery waterflood program or trucked to a SWD well for disposal.

2.2.6.1.3 Conversion of 40-acre Spaced Green River Oil Wells to Injection Wells

Waterflooding consists of pumping water into various isolated Green River Formation oil reservoirs to re-pressurize and displace the oil more efficiently than primary depletion alone. Newfield would use waterflooding technology on the majority (i.e., approximately 60-70 percent) of the proposed 40-acre surface and downhole spaced Green River wells after initial production. Oil well conversion to injection wells would occur after approximately 3 years of production.

During oil well conversion, oil production equipment (anchor, sucker rods, pump jacks, well head valves, flow lines, treater, water tank, and oil tanks) would be removed from the well pad. A packer would be installed on the end of the tubing and set no more than 100 feet above the top perforation. Pressure monitoring gauges would be installed on the wellhead and casing annulus to monitor the pressure at which water is injected and the casing pressure, respectively.

Water injection lines would be installed from the main pipeline to the individual wells to provide water. Injection wells would be equipped with flow meters and choke valves to regulate injected water volumes. After all water injection lines are installed, produced water would be injected into the oil-bearing formation.

2.2.6.2 Maintenance

Routine inspection and maintenance of project facilities within the MBPA would occur on a year-round basis or as ground and site conditions permit. New wells would typically be visited daily by a maintenance worker and 3- to 4-water trucks for approximately 2- to 3-weeks after completion, based on well performance.

When operationally feasible, meters at all producing wells would be equipped with remote telemetry monitoring systems. The system would monitor gas and water production rates, pipeline pressure, and separator pressure to determine if abnormal conditions exist. Control and monitoring of well production by remote telemetry would reduce the number of pumper visits based on well performance.

Project roads would be maintained to provide year-round access. Maintenance would correct excessive soil movement, rutting, holes, replacement of surfacing materials, clearing of sediment blocking ditches and culverts, and/or damage to cattle guards, gates, or fences. Should snow removal be necessary, roads would be cleared with a scraper and snow would be stored along the down gradient side to prohibit runoff onto the road.

Road maintenance agreements and requirements would vary based on the owner of the road in the MBPA. Under existing agreements between the BLM and the counties, Duchesne and Uintah counties maintain segments of BLM roads in the MBPA. Counties would continue to maintain existing county roads. Newfield would be required to maintain access roads to the standards specified in their use authorization, and in accordance with BLM road standards established in the *Gold Book*. Dust control would be achieved by using water or other SMA-approved dust suppressants, such as magnesium carbonate.

2.2.6.2.1 Workovers and Recompletions

Each new well would likely require a workover during the first year of production. A workover rig is similar to a completion rig and performs a variety of maintenance procedures to keep the well operating efficiently. Workovers can include repairs to casing, tubing, rods, pumps, the wellhead, or the production formation itself (i.e., increases or maintains production from downhole-producing zones or to re-complete a well in a new zone). These repairs generally occur during daylight hours and typically would require approximately 3 days. In some limited situations, workovers may require up to 10 days. In the case of a recompletion, where casings are worked on or valves and fittings would be replaced to stimulate production, all by-products would be stored in tanks and hauled from the location to an approved/permitted disposal site.

2.2.7 Final Reclamation and Abandonment

A typical well life span varies from 20 to 30 years. Prior to reclamation of any well pad, pipeline or road, Newfield would file a Notice of Intent (NOI) to abandon with the BLM that details the proposed procedures. The BLM would then attach the appropriate surface rehabilitation COAs for the well pad, and as appropriate, for the associated access road, pipeline, and ancillary facilities. During plugging and abandonment, all other surface equipment, including tanks, pumping unit, three-phase separator, and aboveground flow lines, gas system pipelines, and water pipelines would be removed from the site. Buried pipelines would be purged and left in place. Wellbores would be plugged with cement to prevent fluid or pressure migration and to protect mineral and water resources. Wellheads would be removed, both the surface casing and production casing would be cut off below ground level, and an appropriate dry hole marker would be set in compliance with federal and State regulations and SMA direction. Backfilling, leveling, and recontouring would then be performed according to the appropriate SMA.

All abandoned roads, ROWs, compressor stations, GOSPs, and other surface facilities would be reclaimed as near as practical to their original condition and in compliance with the appropriate SMA. At the time of final abandonment, all surface equipment, including all surface 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. These areas would then be seeded with an SMA-approved seed mixture. Follow-up survey and treatment of weeds and invasive plant species would be conducted until reclamation is deemed to be successful and/or complete.

On Federal lands, reclamation of surface disturbance associated with the proposed project and alternatives would follow the *Green River District Reclamation Guidelines for Reclamation Plans* (BLM 2009). Reclamation plans may be revised and finalized when a site-specific APD and/or ROW application is submitted to the BLM.

2.2.8 Water Requirements

The following section describes water needs for well drilling and completion, dust suppression, and waterflooding operations. Calculations in this document are based on a 42-gallon barrel.

During the early phases of the project, water would be used for drilling and completion purposes and obtained from existing permitted water supply sources (see **Table 2.2.8-1**). These sources would consist of both ground water from wells, surface withdrawals, and from Newfield's proposed water collector well along the Green River. Withdrawals would be made from suppliers that hold existing water rights permits through the Utah Division of Water Rights. During the latter portions of the Project the majority of project water needed would come from recycled produced water.

Water volumes required for drilling, completion, dust suppression, and waterflooding would depend on the alternative selected.

2.2.8.1 Drilling and Completion

Typically 7,000-bbls (0.9 acre-feet) of water would be required to drill and complete a Green River well and approximately 48,000-bbls (6.2 acre-feet) of water would be required to drill and complete a deep gas well. Water used during drilling and completion would be piped to water treatment and injection facilities. The total water use for drilling and completion of all wells could be up to 18,425 acre-feet.

2.2.8.2 Dust Suppression

Water used for dust suppression would represent a small percentage of the total water needs for the proposed project. Dust abatement would be implemented using standard water trucks that hold approximately 130-bbls of water (0.016 acre-feet).

For purposes of analysis, approximately five water trucks (approximately 650-bbls or 0.08 acre-feet) would be needed for dust suppression per new well pad, access road, and pipeline/utility corridor during construction activities for approximately 10 percent of the proposed project (e.g., up to 575 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities under the Proposed Action or Alternative C). Based on these assumptions, and depending on the alternative selected, Newfield could use up to an estimated 46 acre-feet of water for dust suppression during construction activities.

In addition, approximately 1,000-bbls (0.13 acre-feet) of water would be needed annually for dust suppression per well pad, associated access road, and pipeline/utility corridor during project operation. As mentioned above, this would represent approximately 10 percent of the total water needs for the proposed project (e.g., up to 575 well pads and their associated roads, pipeline/utility corridors, and other surface facilities under the Proposed Action and Alternative C). Based on these assumptions, Newfield could use up to an estimated 75 acre-feet of water per year for dust abatement during project operations, or up to 2,296 acre-feet of water for dust suppression over the construction and operational period.

2.2.8.3 Waterflooding Infrastructure and Operations

Depending on the alternative selected, Newfield could convert up to 1,144 of their proposed wells to injection wells that require approximately 11.44 acre-feet of fresh water per day. Annual water requirements for waterflood operations could be up to 4,176 acre-feet per year, or about 140,010 acre-feet over the construction and operational period.

Approximately half of the water for flooding operations could come from produced water that would be treated for injection and the other half could be obtained from freshwater sources identified in **Table 2.2.8-1**. Fresh water for waterflooding and infrastructure and operations would come from sources identified in **Table 2.2.8-1** and Newfield's proposed water collector well, which is described in **Section 2.2.8.3.1.**

Table 2.2.8-1. Existing Water Supply Sources for the Monument Butte Project

Base Water Right	Segregated Water Right	Supplemental Group Number	Change Number	Filing Date	Source	Location	Annual Volume (acre/ft.)	Use	Depletion
43-7478	None	217235	a11187	4/29/74	Underground Water Well	N 500 ft. W 110 ft. from SE cor, Sec 30, T2S, R2W; N 2,407 ft. W 200 ft. from SE cor Sec 30, T2S, R2W	225.0	Municipal	Historic
47-1358	None	None	t37916	6/26/63	Tributary to Pleasant Valley Wash	N 1,410 ft. E 1,450 ft. from W4 cor Sec 7, T4S R1W	99.0	Industrial: O&G Drilling	Historic
41-3530	47-1817	621892	a31022	2/6/06	Duchesne County Water Conservation District	S 1,087 ft. E 1020 ft. from N4 cor, Sec 15 T2N, R22E	690.0	Industrial: O&G Recovery	New
41-3530	47-1821	None	a31022a	10/29/09	Duchesne County Water Conservation District	S 413 ft. E 1225 ft. from N4 cor, Sec 27, T9S, R19E	2,210.0	Industrial: O&G Recovery	New
47-1802	None	225664	a34586	4/23/94	Green River Collector Well	S 413 ft. E 1225 ft. from N4 cor, Sec 27, T9S, R19E	941.1	Industrial: O&G Recovery	New
47-1804	None	225666	a34585	12/4/95	Green River Collector Well	S 413 ft. E 1225 ft. from N4 cor, Sec 27, T9S, R19E	941.1	Industrial: O&G Recovery	New
Total	--	--	--	--	--	--	**5,106.2**	--	--

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2.2.8.3.1 Water Collection Station

Up to approximately 1 acre of temporary surface disturbance would occur within the floodplain for construction of the water source well. The water source well would extend to a depth of approximately 100 feet below the surface and would be developed using conventional drilling methods. An example diagram of a water source well (i.e., depicting one well with five laterals) and the associated water processing station from Newfield's existing water collection station in the SE1/4 of Section 22 and NE ¼ of Section 27, T9N:R19E is included in **Figure 2.2.8.3-1 – Attachment 1**.

Each lateral would require a temporary pad approximately 100 feet by 100 feet in size (0.2 acre) to drill the hole and install the pump. Following successful reclamation, surface disturbance within the floodplain would be limited to the manhole cover on each well and the area immediately surrounding the manhole. The water source well would be equipped with steel casing between 10 to 14 inches in diameter. This casing would include sections of stainless steel screening that would allow groundwater to move from the surrounding alluvial aquifer into the wellbore. The screen opening typically would be no larger than 0.1 inch. The well casing would terminate 1 foot below the ground surface. The top of the casing would be capped with a bolt-down lid. A manhole structure and manhole lid also may be placed around the well casing with the lid flush to the ground surface. The area adjacent to and surrounding the manhole would be graded to the top of the manhole and seeded with a native, site-specific seed mix to blend with the surrounding areas.

The water source well would contain a submersible pump, motor, and electric cable. The pump and motor would be sealed in casing to prevent potential leaks of petroleum products (i.e., lube oil). The pump would be connected to a 6- to 8-inch outer diameter pipe, known as a carrier pipe, which would convey the pumped water from the water source well to the water processing station on the same side of the Green River. This carrier piping would be buried 5 feet below ground surface (bgs) to prevent freezing and avoid long-term surface disturbance within the floodplain. Installation of the water source well would occur during the low-flow season of the Green River (fall/winter).

The water processing station would require an area of 200 feet by 150 feet (0.7 acre) of surface disturbance located adjacent to, but outside of, the Green River 100-year floodplain. Power for the water processing station would be provided by a 300 to 600 horsepower generator that would be located within a building. Onsite power generation would utilize either produced natural gas or natural gas liquid (NGL) as a fuel source to power the generator associated with the processing station. The generator would power the fresh water well pump and booster pump that would transport the water to each of the injection wells. The water processing station would include a hydrocyclone system to remove solids from the waterflood system for injection. A hydrocyclone is a stationary device that uses centrifugal force to separate solids such as fine sand from the water. This system would solids from the water and would have a combined capacity of 20,000 bpd. The water processing station would likely be located on private land, and is subject to landowner negotiations and site-specific conditions. Therefore, a conceptual location for the water collector station is not identified in this EIS.

The water processing station would include a 40-foot by 40-foot parking lot and a building approximately 30 feet long by 25 feet wide with walls approximately 10 feet high. The parking lot would be graded and graveled. The building would be constructed of either cinder block or metal siding finished in an earth tone. The roof on the building would be pitched, of metal construction, and also would be finished in an earth tone. If noise attenuation of the generator does not reduce noise to 45 dB, critical grade mufflers would be installed to further reduce noise levels. Tree and shrub species recommended by the surface owner would be planted along the sides of the building facing the Green River so that the building would be screened to minimize its visibility from the Green River. In addition, Newfield would develop a landscaping plan describing plant spacing and irrigation and maintenance requirements.

Water from the fresh water collection areas would be either pumped into a wet well (cistern) located beneath the building or piped directly to the booster pumps for distribution via buried pipelines to the well field. Some excess water may occur during initial flow back immediately after drilling the well. All water is groundwater and no chemicals filtering or treatment of the water occurs. The volume of water is small and this occurs infrequently. Once connected, 100% of the water produced by the well is contained within infrastructure and no discharges occur.

A network of buried, high pressure water pipelines would supply both fresh water and treated water from the central water processing station to the injection wells. These water pipelines would be buried approximately 4 to 5 feet deep within the same ROWs proposed for roads and other pipelines. Approximately 8 miles of 6-inch steel trunk lines and 4 miles of 3-inch steel lateral lines would be constructed to transport water from the central water processing facility to the injection wells. The injection wells would be equipped with flow meters and choke valves to regulate injected water volumes. Water pipelines would be from 4 to 8-inches in diameter and constructed from steel and/or polypropylene. These water pipelines would be buried to prevent freezing and would be installed in conjunction with (alongside) the high pressure gas gathering pipelines, where possible.

2.2.8.4 Water Depletion and Previous USFWS Consultations

Newfield currently has secured water rights for up to 5,106 acre-feet per year from the water supply sources identified in **Table 2.2.8-1**. Water from these sources will be used for drilling, completion, dust suppression, and waterflood operations. Of this volume for existing water rights, 324 acre-feet are from water sources considered historic depletions under the Recovery Implementation Program for Endangered Fish Species in the Upper Colorado River Basin (USFWS 1987). Section 7 consultation was completed for all historic depletions in 1993 (USFWS 1993). As part of this consultation, it was determined that historic depletions, regardless of size, do not pay a depletion fee to the Recovery Program.

In addition, three consultations have been completed for water depletions associated with oil and gas development projects in the MBPA. Currently, a total annual volume of 3,328 acre-feet has been authorized through these consultations (see **Table 2.2.8.4-1**). Water used under these previous consultations, plus the historic water rights equals a total of 3,652 acre-feet of water available for this project that have gone through the Section 7 Consultation process. Any additional water needed for the proposed project (e.g., water from (WR 41-3530; WR 47-1802; WR 47-1804 and the proposed water collector well) would require additional consultation.

Table 2.2.8.4-1 Previous USFWS Consultations for Water Usage in the MBPA

Project	Biological Opinion	Date	Consulted Water Volume	Depletion Payment
Final Formal Section 7 Consultation for Castle Peak Eightmile Flat Oil and Gas Expansion Project	6-UT-05-012 05-0600	7/6/05	2,081 acre-feet	$33,920.30
Amendment to Formal Section 7 Consultation for Castle Peak Eightmile Flat Oil and Gas Expansion Project Re: 6-UT-F-05-F012	FWS/R6	4/11/06	819 acre-feet	$13,652.73

Project	Biological Opinion	Date	Consulted Water Volume	Depletion Payment
Final Biological Opinion for Newfield's 20-acre Infill Development Project	06E23000-2012-F-0024 6-UT-12-F-002	1/20/12	428 acre-feet	$8,221.88
Total	--	--	**3,328 acre-feet**	**$55,794.91**

2.2.9 Produced Water Disposal

Produced water from newly completed wells may be temporarily disposed of within lined reserve pits or storage tanks for a period not to exceed 360 days after initial production on State or private land (per UDOGM regulations) and 90 days on BLM-administered lands (per *Onshore Oil and Gas Order No. 7*). On BLM-administered lands, pits may be reused if additional wells are drilled from the same well pad within a 1-year time frame.

Additional produced water disposal wells would likely be drilled in the MBPA on existing well pads, or existing wellbores would be converted from deep 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 Newfield's preferred method of produced water disposal.

Underground injection wells used in conjunction with oil and gas production are referred to as Class II wells under the EPA Underground Injection Control (UIC) program. 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 (RCRA), Subpart D (mainly produced water). In December of 2012, Newfield received an approved UIC Area Permit from the EPA for the MBPA (Area UIC Permit No. UT22197-0000). Within the MBPA, Newfield currently operates 517 UIC wells under UDOGM jurisdiction, and 538 UIC wells under EPA jurisdiction, all of which support their secondary recovery program. Newfield operate one SWD well in the MBPA (i.e., the GMBU Pariette 4-7-9-19).

Permitting of Class II wells is regulated in Utah by UDOGM and the EPA for Indian trust lands[3]. The permit process requires agency review of the application and a 15- to 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 would be approved administratively.

Up to three water treatment and injection facilities would be constructed. The proposed water treatment facilities would be used for recycling of produced water that would either be co-mingled with fresh water and piped for waterflood injection wells or trucked from the facility to be used at subsequent wells for completion activities. Conceptual locations for water treatment and injection facilities have been illustrated on each alternative map (see **Figures 2-1** through **2-4 – Attachment 1).**

[3] The State of Utah has primacy for the UIC program outside of Indian Country. The US EPA retains primacy for UIC in Indian Country under the Safe Drinking Water Act. In the MBPA, the EPA Region 8 office administers Range 17E–19E.

2.2.10 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.

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 *Instruction Memorandum No. 93-344*. Most wastes that would be generated at project locations are excluded from regulation by the RCRA 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 inlet of the gas plant. Exempt wastes include produced water, production fluids such as drilling mud or well stimulation flowback, and crude oil impacted soils.

Any spills of oil, gas, salt water, or other such fluids would be cleaned up and removed to an approved disposal site. Spills at least 10-barrels in non-sensitive areas would be reported to the AO in a written report and other appropriate authorities. Major undesirable events of 100 barrels or more must be reported to the AO within a maximum of 24 hours; however, if the spill is entirely contained within the facility firewall, it may be reported only in writing pursuant to Section III of NTL-3A. Any spill regardless of the volume involved, which occurs in a sensitive area, must be reported within 24 hours to the AO. Drilling and production operations would require preparation of a Spill Prevention Containment and Control (SPCC) plan that outlines the methodology to be used in the event of a spill. The SPCC plan describes spill control, reporting, and cleanup procedures to help prevent impacts to surface and subsurface waters. A copy of the drilling company's SPCC plan would be kept on site during drilling operations. All produced liquid hydrocarbons would be stored in tanks surrounded by a secondary containment berm of sufficient capacity to contain the entire capacity of the largest single container with sufficient freeboard for precipitation. All loading lines and valves would be placed inside the berm surrounding the tank or would use catchment basins to contain spills. The tanks would be emptied as necessary to prevent overflow, and the liquids transported to market via trucks and/or pipelines.

Portable toilets and trash containers would be located on active construction sites throughout the MBPA. A commercial supplier would install and maintain portable toilets and equipment and would be responsible for removing sanitary waste. Sanitary waste facilities (i.e., toilet holding tanks) would be regularly pumped and their contents disposed of at approved sewage disposal facilities in Carbon, Duchesne, and/or Uintah Counties, in accordance with applicable rules and regulations regarding sewage treatment and disposal.

Accumulated trash and nonflammable waste materials would be hauled to an approved landfill once a week or as often as necessary. All debris and waste materials not contained in the trash containers would be cleaned up, removed from the construction ROW or well pad and disposed of at an approved landfill. Sanitary waste equipment and trash bins would be removed from the MBPA upon completion of the construction of well pads, access roads, and other surface facilities, and following drilling and completion operations at well pads.

2.2.11 Adaptive Management Strategy for Potential Adverse Ozone Formation

Ozone concentrations in the Uinta Basin have been found to be exceeding National Ambient Air Quality Standards (NAAQS) during periodic winter inversion events. A comprehensive understanding of the chemical pathways, analytical methodologies, and demonstrable control technologies and methods has been lacking to allow for a scientifically based examination of this issue in recent NEPA documents relating to oil and gas production in the Uinta Basin. To address the uncertainty relating to this, BLM has been including adaptive management requirements in both recent and current NEPA documents relating to significant oil and gas development in the Basin. One of the components of these adaptive management prescriptions is the commitment to apply enhanced mitigation for ozone when an exceedance of the ozone NAAQS has been measured and recognized based on criteria in the Clean Air Act that defines how NAAQS determinations are made (40 CFR Part 50). Based on recent studies (citation pending, 2013), BLM believes this adaptive management requirement for enhanced mitigation has been triggered, and that tentative control determinations can be made at this time as an initial start in controlling and preventing winter ozone formation.

Over the past 3 years significant research had been conducted in the Uinta Basin to further the understanding of winter ozone formation (Martin et. al. 2011). These studies to date are indicating that volatile organic compound (VOC) controls and seasonal response plans are the most promising avenues to address winter ozone formation. BLM, in consultation with the Utah Division of Air Quality (UDAQ) and the U.S Environmental Protection Agency (EPA), has developed a list of enhanced seasonal pollution control measures and work practices specifically aimed at reducing the emissions of VOCs which form winter ozone. These control measures and work practices will be required for all operations approved under this NEPA action, and will be retroactively applied to other recent oil and gas NEPA in the Uinta Basin that have adaptive management requirements.

It is recognized in this adaptive management prescription that additional research and analysis needs to be conducted in the Uinta Basin to more fully understand the mechanics of winter ozone formation, and that specific control and work practice recommendations may change over time. To address the continued scientific uncertainty on this issue, BLM will continue to include an adaptive management requirement in oil and gas NEPA for the Uinta Basin. Once a basin-wide control plan is developed and approved by UDAQ and/or EPA, BLM will review these enhanced mitigation requirements and may add, delete, or otherwise modify these requirement to conform to the requirements or recommendations of a regulatory basin-wide management plan. These adaptive management modifications will be applicable to this NEPA action and all other NEPA actions already approved or to be approved by BLM in the Uinta Basin.

In order to assess and mitigate (if necessary) the potential for adverse ozone formation in the Uinta Basin, an Adaptive Management Strategy will be implemented under all of the action alternatives (i.e., the Proposed Action, Alternative C, and Alternative D). The Adaptive Management Strategy includes the following major elements:

- Newfield will conduct an annual emissions inventory and compare the inventory to the emissions estimates contained in this EIS. The inventory will be conducted annually for the life of the project (LOP) until the EPA/UDEQ/BLM develop an approved basin-wide control plan covering oil and gas development in the Uinta Basin.

- Regional photochemical modeling will be conducted that includes emissions for the selected alternative within one year of the ROD for this project or one year of the BLM Air Resources Management Strategy (ARMS) modeling platform becoming available, whichever occurs first. If modeled impacts show that the National Ambient Air Quality Standards (NAAQS) or applicable thresholds for air quality related values may be exceeded, BLM will require additional mitigation measures within BLM's authority to prevent exceedances (for example requiring Newfield to implement an ozone mitigation contingency plan as described below).

The enhanced mitigation requirements to address winter ozone are as follows:

<u>Enhanced Inspection and Maintenance Program</u>

- FLIR/AVO inspections
  - Pneumatic devices / pumps
  - Tanks
  - Fugitives
- Frequency
  - Production sites with tank controls / compressor stations / gas plants
    - Annual FLIR inspection, with at least one inspection during Jan-Mar at highest priority sites based upon PTE (potential to emit) limits considered significant to ozone formation (determined by operator)
    - AVO inspection by operators during any site visits Jan-Mar.
  - Production sites with no tank controls
    - Annual AVO inspections
    - AVO inspection by operators during any site visits Jan-Mar.
- Perform regular maintenance on pneumatic devices, dehydrators, combustors, engines and compressors
- Properly operate and maintain existing installed control equipment

<u>Ozone Training for Operations Personnel</u> – Operations personnel receive training prior to ozone season. Training programs should cover the following:

- Ozone – what it is and how to it impact air quality
- Ozone formation ingredients – NOx, VOCs, and weather conditions
- Ozone attainment status in the Uinta Basin
- Review of applicable regulations
- What can be done to prevent and/or reduce emissions of ozone precursor gases – limit driving, maintain equipment, delay optional activities until after inversion, etc. Emphasize importance of proper maintenance of tank hatches, vapor combustors, and other equipment that reduces emissions.

<u>Work Practices</u>

- Dehydrators
  - Perform charging of desiccant dehydration units prior to the winter ozone season
  - Reduce glycol dehydration circulation rates throughout entire winter ozone season
- Venting Blow Downs
  - Minimize blow down actions associated with energy recovery and production during the entire winter ozone season
- Venting – compressor startup and shutdown
  - Reduce the number of failed startups by performing regular maintenance of compressor throughout the entire winter ozone season

  - Reduce the number of compressor startups and shutdowns by having operating and maintenance schedules, and performing regular maintenance of compressors only during planned compressor shutdowns as possible throughout the entire winter ozone season
- Episodic Controls
  - Delay optional activities associated with energy recovery and production during periods of UDAQ ozone alert days.
  - Take extra care to ensure proper maintenance and operation of equipment associated with energy recovery and production that may contribute to ozone formation during UDAQ ozone alert days.

2.2.12 Applicant-Committed Environmental Protection Measures (ACEPMs)

Under the action alternatives, Newfield has committed to the following measures to reduce the potential environmental impacts of the proposed oil and natural gas development and waterflooding operations within the MBPA. The following ACEPMs would apply to all Federal lands within the MBPA.

2.2.12.1 Air Quality

2.2.12.1.1 General

- Newfield would use water or other BLM-approved dust suppressants as needed during drilling, completion, and high traffic production operations for dust abatement.

- Newfield employees would comply with posted speed limits on unpaved county roads used for access and would use safe vehicle speeds on other unpaved access roads. Newfield would instruct contractors to comply with posted speed limits.

- The use of carpooling would be encouraged to minimize vehicle traffic and related emissions and Newfield will implement a vehicle policy to minimize idling while also recognizing safety concerns.

- Newfield would conduct a pilot test to evaluate the feasibility for converting fleet vehicles to cleaner burning compressed natural gas (CNG) or liquefied natural gas (LNG) fuels. The results of this pilot test would be submitted to the AO.

2.2.12.1.2 Drilling / Completion Operations

- Newfield would use Tier II diesel drill rig engines or equivalent with the phase-in of Tier IV engines or equivalent emission reduction technology by 2018.

- Newfield would employ reduced emission completion practices, including storing or re-injecting recovered liquids and routing recovered gas into a well or using the recovered gas as fuel for another useful purpose when feasible; routing all saleable quality gas to a flow line as soon as practicable; and safely maximizing resource recovery and minimizing potential VOC emissions from hydraulically fractured, high pressure gas well flowback operations. If flowback emissions cannot be routed to a flow line, they will be captured and routed to a completion combustion device unless such device will result in a fire or explosion hazard.

2.2.12.1.3 Production Operations

- Newfield would utilize low or intermittent bleed pneumatic devices to minimize VOC emissions. High bleed devices may be allowed for critical safety and/or process purposes. Intermittent pneumatic devices will be operated such that average emissions are no greater than for a low bleed device.

- High bleed pneumatic devices at existing Newfield facilities would be replaced/retrofitted with low or intermittent bleed devices when repair or replacement is warranted, and no later than 6 months after the ROD is signed. High bleed devices may be allowed to remain in service for critical safety and/or process purposes.

- Newfield would employ glycol dehydrator still vent emission controls with a control efficiency of 95 percent or greater.

- Newfield would conduct a study to evaluate the feasibility for the implementation of "low emission" glycol dehydrators. The results of this study would be submitted to the AO.

- Newfield would install emission controls with an efficiency of 95 percent on the following:
    - New oil and condensate storage tanks
    - Tanks that have been modified or re-constructed after August 23, 2011, with the potential to emit greater than 6 tons per year (tpy) VOC
    - All other tanks with the potential to emit greater than 20 tpy within 24 months of signing the ROD

- Newfield would implement a telemetry monitoring system where feasible to provide for the effective management of production exceptions, while reducing the number of vehicle trips and miles traveled.

2.2.12.1.4 Central Facilities

- Newfield would install electric motor driven compression where feasible. Where electrification is not feasible, Newfield would utilize lean-burn natural gas fired compressor engines or equivalent rich-burn engines with catalysts. Lean-burn engines would be fitted with oxidation catalysts to minimize carbon monoxide and VOC emissions.

- Newfield would maximize the use of central compression, thereby reducing the need for smaller and less efficient (higher emission) well site compressor units.

- Newfield would periodically replace rod packing systems on reciprocating compressors and use only dry seals on centrifugal compressors to minimize the loss of VOC.

- Newfield would employ glycol dehydrator still vent emission controls with a control efficiency of 95 percent or greater.

- Newfield would install emission controls with an efficiency of 95 percent or greater on stock tanks that have the potential to emit VOC greater than 6 tpy.

2.2.12.1.5 GOSP Implementation

- Where feasible, Newfield would implement Green River oil gathering systems and construct GOSPs. With GOSP implementation, the majority of the stock tanks, produced water tanks, and related tank heaters at affected existing well sites would be removed from service. New wells served by a GOSP would be constructed without tank batteries, thereby eliminating tank battery and related tanker truck emissions.

- The GOSP facilities would be specifically designed to minimize the emission of VOC. Storage tank emissions would be captured and reused within the facility process or sold as product. Vapors from truck loading operations would be controlled by 95 percent.

2.2.12.1.6 Monitoring Programs

- Newfield would annually evaluate the deep gas gathering system to identify opportunities for pressure optimization resulting in reduced flash emissions from condensate storage tanks.

- Newfield would implement visual inspections of thief hatch seals and pressure relief valves on condensate tanks to ensure proper operation and minimize losses of VOCs. Inspections will be conducted at least annually during a routine maintenance visit. If for some reason monitoring does not occur within 12 months, the visual inspection will be conducted at the next scheduled maintenance visit.

2.2.12.1.7 Adaptive Management

- Newfield would implement the adaptive management program described in Section 2.2.11, would evaluate project specific emissions on an annual basis, and would identify opportunities to further reduce emissions.

2.2.12.1.8 Cooperative Efforts and Outreach

- Newfield would encourage and lend technical support to scientific research efforts focused on improving the understanding of ozone formation chemistry within the Uinta Basin, emission inventory enhancements, source apportionment studies, ozone precursor transport studies, precursor sensitivity studies, and evaluations of cost effective control strategies.

- Newfield would incorporate ozone awareness and specific actions for reducing ozone precursor emissions into the current employee training program.

2.2.12.2 Paleontological Resources

- Paleontological surveys would be conducted by an SMA-approved paleontologist prior to any surface disturbance on State and Federal surface.

- If fossils are encountered during the survey, the paleontologist would assess and document the discovery, and either collect the fossils or recommend the area be avoided so as not to destroy the resource.

- The AO of the SMA would determine the need for further monitoring of the area or mitigation of the site during ground-disturbing activities.

- If paleontological resources are encountered during excavation, construction would be suspended, and the AO of the SMA would be notified. Construction would not resume until the paleontological resources are assessed by the AO of the SMA and appropriate mitigation measures are developed and implemented.

2.2.12.3 Soil Resources

- During project construction, surface disturbance and placement of gas and water lines would be limited to the approved location and access routes.
- No oil, lubricants, or toxic substances would be drained onto the ground surface.
- All areas used for soil storage would be stripped of topsoil before soil placement.
- Where directed by the appropriate SMA, Newfield would construct erosion control devices (e.g., riprap, bales, and heavy vegetation) at culvert outlets. All construction activities would be performed to retain natural water flows to the greatest extent possible.
- In areas with unstable soils where seeding alone may not adequately control erosion, grading would be used to minimize slopes and water bars would be installed on disturbed slopes.
- Erosion control efforts would be monitored by Newfield and, if necessary, modifications would be made to control erosion.
- Erosion protection and silt retention would be provided by the construction of silt catchment dams where needed and as feasible.

2.2.12.4 Water Resources, Including Floodplains

- Produced liquid and natural gas gathering pipelines that are buried across water courses would be buried in accordance with guidelines established in the *Gold Book* and *Hydraulic Considerations for Pipelines Crossing Stream Channels*, Technical Note 423, April 2007. Specific burial depths for natural gas and produced liquids pipelines that cross perennial, intermittent, and ephemeral stream channels within the MBPA would be determined during the onsite process.
- In accordance with 40 CFR 112.3, Newfield will prepare and maintain SPCC plans for active facilities. Newfield will inspect each facility subject to SPCC requirements on an annual basis to ensure appropriate spill prevention measures are maintained. A management review of the SPCC plans will be conducted every 5 years.
- Newfield employees will be trained annually in spill prevention and reporting requirements. Contractors will be required to promptly report all accidental releases to a Newfield Supervisor.
- Newfield would use closed-loop drilling techniques for all proposed wells located in sensitive areas such as the 100-year floodplain of Pariette Draw, and in all USGS named drainages within 3 miles of the Green River. Additional locations where closed-loop drilling may be merited would be determined during the onsite process.

- Newly constructed gas and water lines would be pressure tested to evaluate structural soundness and reduce the potential for leaks.

- Springs will be delineated and marked on maps and on the ground before development.

2.2.12.5 Vegetation, Including Noxious and Invasive Species and Wetland/Riparian Areas and Threatened, Endangered, or BLM Special-status Plant Species

- As required by the Endangered Species Act (ESA) of 1973, as amended, no activities would be permitted that would jeopardize the continued existence of threatened or endangered plant species.

- As required by the Noxious Weed Act of 1974 as amended and Executive Order 13112-1999, noxious weeds would be controlled in the MBPA by Newfield on all disturbances associated with their existing well pads, road, and pipeline routes as well as infestations that would occur as a result of the project.

- Removal and disturbance of vegetation would be kept to a minimum through construction site management (e.g., using previously disturbed areas and existing easements where feasible, placing pipelines adjacent to roads, limiting well pad expansion, etc.).

- In an effort to ensure that project activities do not increase the existence of invasive or noxious weeds in the MBPA, Newfield would prepare a Weed Control Plan. Specific components of the plan would include:

    - Conducting individual noxious weed inventories on a well-by-well basis prior to construction activities. The inventories would include examination of all proposed surface disturbance (i.e., roads, pipelines, and well pads) associated with each well. The results of these inventories would include Global Positioning System (GPS) locations indicating the type and size of each infestation. This data would be formulated into a report and submitted with the APD.

    - Preparation of a Pesticide Use Proposal (PUP).

    - Following the construction phase and drilling phase for each well, all disturbed surface would be monitored annually for the presence of noxious weeds. If monitoring shows the presence of noxious weeds, Newfield would be responsible for treating these areas. Noxious plant control measures (mechanical, cultural, chemical) would be conducted annually prior to seed set. Monitoring and treatment would be conducted annually until reclamation and weed eradication was deemed successful by the AO of the appropriate SMA.

    - All herbicide chemical control will be in conformance with national and local guidance, including approved chemicals, rates, and appropriate BMPs.

    - To prevent further spread of noxious weeds, all vehicles and equipment would be power washed at designated washing locations to remove seed and plant materials before entering the MBPA from outside of the Uinta Basin.

  - o Springs will be delineated and marked on maps and on the ground before development.

2.2.12.6 Livestock Grazing

- Newfield would repair or replace any fences, cattle guards, gates, drift fences, and natural barriers that are damaged as a result of the Proposed Action. Cattle guards or gates would be installed for livestock control on roads when fences are crossed and these structures would be maintained by Newfield for the life of the road.

2.2.12.7 Fish and Wildlife Including Special Status Fish and Wildlife Species

- As required by *Onshore Oil and Gas Order No. 1*, Newfield would remove any visible accumulation of oil from the reserve pit immediately upon release of drilling rig to prevent exposure of migratory birds and other wildlife to petroleum products.

- To minimize wildlife mortality due to vehicle collisions, Newfield would advise project personnel regarding appropriate speed limits in the MBPA.

- Employees and contractors would be educated about anti-poaching laws.

- If wildlife law violations are discovered, the offending employee would be subject to disciplinary action by Newfield. All wildlife law violations would be reported to the UDWR.

- For any surface-disturbing activities proposed between January 1 and September 31, a BLM-approved biologist would survey proposed development sites for the presence of raptor nests. The survey area would be determined on a site-specific basis by the AO of the appropriate SMA. On BLM lands, if occupied/active raptor nests are found, construction would not occur during the nesting season for that species within the species-specific buffer described in “Best Management Practices for Raptors and Their Associated Habitats in Utah.” As specified in the Raptor BMPs, modifications of these spatial and seasonal buffers for BLM-authorized actions would be permitted, so long as protection of nesting raptors was ensured (see Appendix A of the Vernal ROD and Approved RMP) (BLM 2008b). Fee and SITLA lands would be excluded from this measure.

2.2.12.8 Cultural Resources

- A Class III inventory would be conducted in all areas within Federal lands proposed for surface disturbance. These surveys would be conducted on a site-specific basis prior to the initiation of construction activities.

- Whenever feasible, prehistoric and historic sites documented during the Class III inventory as eligible for listing on the National Register of Historic Places (NRHP), as well as areas identified as having a high probability of subsurface materials, would be avoided by development. Specifically, well pad locations and access/gas and water line routes would be altered or rerouted as necessary to avoid impacting NRHP-eligible sites.

- If avoidance is not feasible or does not provide the required protection, adverse effects would be mitigated (e.g., data recovery through excavation).

- Newfield would inform their employees, contractors, and subcontractors about relevant Federal regulations intended to protect archaeological and cultural resources. All personnel would be informed that collecting artifacts is a violation of Federal law and that employees engaged in this activity would be subject to disciplinary action.

- If cultural resources are uncovered during surface-disturbing activities, Newfield would suspend operations at the site and immediately contact the appropriate AO, who would arrange for a determination of eligibility in consultation with the Utah State Historic Preservation Office (SHPO) and if necessary, would recommend a recovery or avoidance plan.

2.2.12.9 Visual Resources

- To reduce visual impacts to recreationists using the Green River, low profile tanks would be used at all well pads located within 0.5-mile or line of sight (whichever is less) of the Green River.

2.2.12.10 Health and Safety/Hazardous Materials

- Newfield would institute a Hazard Communication Program (HCP) for its employees and require the subcontractor to operate in accordance with Occupational Safety and Health Administration (OSHA) (29 CFR 1910.1200).

- As required by OSHA, Newfield would place warning signs near hazardous areas and along access roads.

- In accordance with 29 CFR 1910.1200, a Material Safety Data Sheet (MSDS) for every chemical or hazardous material brought on-site would be kept on file in Newfield's field office.

- Newfield would transport and/or dispose of any hazardous wastes, as defined by the Resource Conservation and Recovery Act of 1976 (RCRA), as amended, in accordance with all applicable Federal, State, and local regulations.

- All storage tanks that contain produced water, or other fluids which may constitute a hazard to public health or safety, would be surrounded by a secondary means of containment for the entire contents of the tank, plus freeboard for precipitation, or 110 percent of the capacity of the largest tank. Production facilities that have the potential to leak produced water, or other fluids, which may constitute a hazard to public health or safety, would be placed within appropriate containment and/or diversionary structure to prevent spilled or leaking fluid from reaching groundwater or surface waters.

- Notice of any reportable spill or leakage, as defined in BLM NTL 3A, would be reported by Newfield to the AO of the appropriate SMA as required by law. Oral notice would be given as soon as possible, but within no more than 24-hours, and those oral notices would be confirmed in writing within 72-hours of any such occurrence.

- Newfield would provide portable sanitation facilities at drill sites, place trash cages at each construction site to collect and store garbage and refuse, and ensure that all garbage and refuse is transported to a State-approved sanitary landfill for disposal.

2.3 ALTERNATIVE A – PROPOSED ACTION

The Proposed Action includes the following primary components (see **Figure 2-1 – Attachment 1**):

- Development of up to 750 Green River oil wells on 40-acre surface and downhole spacing drilled from new 2-acre well pads, all of which would be converted into waterflood injection wells after approximately 3 years of production;
- Development of up to 2,500 Green River oil wells on 20-acre downhole spacing that would be vertically, directionally, or horizontally drilled from existing and/or proposed 40-acre surface spaced Green River oil well pads, consistent with current State spacing requirements;
- Development of up to 2,500 vertical deep gas wells on 40-acre surface and downhole spacing drilled from new 3-acre well pads, which would be constructed adjacent to Green River oil well pads to reduce new surface disturbance and use existing utility infrastructure and access roads;
- Construction of approximately 243 miles of new 100-foot wide ROW that would be used for new road construction (40-foot width) and pipeline installation (60-foot width). Up to 70-foot wide expansion along approximately 363 miles of existing access road ROW that would be used for road upgrade (10-foot width) and pipeline installation (60-foot width);
- Construction of 20 new compressor stations for deep gas well development;
- Expansion of three existing Green River oil well compressor stations and construction of one new compressor station for gas associated with Green River oil well development;
- Construction of a 50 MMscf/d centralized gas processing plant;
- Construction of seven new and expansion of six existing water treatment and injection facilities for management and distribution and injection of produced water;
- Construction of up to 12 GOSPs for oil and produced water collection;
- Development of one fresh water collector well for waterflood operations; and
- Construction of six water pump stations.

Figure 2.3-1 – Attachment 1 shows active, inactive, and future UDOGM wells that occur within the MBPA boundary, including well status and well counts. Newfield currently operates approximately 3,395 oil and gas wells in the MBPA and proposes to drill associated wells at an average rate of 360 wells per year until the resource base is fully developed. Under this drilling scenario, construction, drilling, and completion of up to 5,750 wells would occur for approximately 16 years. The total number of wells drilled would depend largely on outside factors such as production success, engineering technology, reservoir characteristics, economic factors, commodity prices, rig availability, and lease stipulations. The anticipated life of an individual well is 20 to 30 years, and the anticipated time it would take for field abandonment and final reclamation is 5 years. Therefore, the anticipated life of project (LOP) under the Proposed Action would be from 41 to 51 years.

Surface disturbance anticipated under the Proposed Action is shown in **Table 2.3-1**. Initial surface disturbance would occur during and immediately after the construction, drilling, completion, and testing activities. Prior to interim reclamation, initial surface disturbance for well pads, access roads, pipeline ROWs, and other surface facilities would equal approximately 16,129 acres. Those portions of the well pads, access road ROWs, pipeline ROWs, and other facilities not needed for production operations would be reclaimed within two to three growing seasons assuming optimal conditions are present. The remaining surface disturbance would be residual or "long-term" disturbance of approximately 7,808 acres for the 41 to 51-year LOP.

Specific details of construction-related activities and specific design features for well drilling and completion; production, operations, and maintenance activities; final reclamation and abandonment; and hazardous materials and solid waste under the Proposed Action are identical to those previously described in **Section 2.2**, *Development Activities Common to All Action Alternatives* and will not be repeated further in this section. Details of project activities, design features, and surface disturbance summaries that are unique to the Proposed Action are described below in the following sections.

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Table 2.3-1. Surface Disturbance under the Proposed Action

Project Feature	Size (disturbance width [feet] or acres/facility)	Federal Lands			State Lands			Private Lands			Project Total		
		Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]
Well Pads													
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	2.0 acres	632	1,264	632	86	172	86	32	64	32	750	1,500	750
New Green River Oil Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	0.2 acre	2,135	427	427	300	60	60	65	13	13	2,500	500	500
New Deep Gas Well Pads on 40-Acre Surface and Downhole Spacing	3.0 acres	2,135	6,405	2,135	300	900	300	65	195	65	2,500	7,500	2,500
Subtotal	--	**4,902**	**8,096**	**3,194**	**686**	**1,132**	**446**	**162**	**272**	**110**	**5,750**	**9,500**	**3,750**
Access Roads													
New Roads Co-located with Pipelines	40 feet[2]	208 miles	1,008	1,008	31 miles	150	150	4 miles	19	19	243 miles	1,178	1,178
Existing Roads Co-located with New Pipelines	10 feet[3]	311 miles	377	377	34 miles	41	41	18 miles	22	22	363 miles	440	440
Subtotal	--	**519 miles**	**1,385**	**1,385**	**65 miles**	**192**	**192**	**22 miles**	**41**	**41**	**606 miles**	**1,618**	**1,618**
Pipelines													
Pipelines Co-located with New Roads	60 feet[4]	208 miles	1,513	630	31 miles	225	94	4 miles	29	12	243 miles	1,767	736[5]
Pipelines Co-located with Existing Roads	60 feet[4]	311 miles	2,262	942	34 miles	247	103	18 miles	131	55	363 miles	2,640	1,100[5]
Subtotal	--	**519 miles**	**3,775**	**1,573**	**65 miles**	**473**	**197**	**22 miles**	**160**	**67**	**606 miles**	**4,407**	**1,836**
Central Facilities													
Compressor Stations (New and Upgrades)	9.4 acres (avg.)	21	197	197	3	28	28	0	0	0	24	226	226
Gas Processing Plants	10.0 acres	0	0	0	1	10	10	0	0	0	1	10	10
Water Treatment and Injection Facilities	8/5 acres[6]	12	78	0	1	8	0	0	0	0	13[7]	86	86
Gas and Oil Separation Plants (GOSPs)	22.0 acres	10	220	220	2	44	44	0	0	0	12	264	264
Fresh Water Collector Well	1.7 acre	1	0	0	0	0	0	0	0	0	1	1.7	0.7
Pump Stations	3.0 acres	5	15	15	0	0	0	1	3	3	6	18	18
Subtotal	--	**49**	**433**	**433**	**7**	**82**	**82**	**1**	**3**	**3**	**57**	**604**	**604**
Total New Disturbance	--	--	**13,767**	**6,663**	--	**1,886**	**925**	--	**476**	**221**	-	**16,129[8]**	**7,808**

Source Note: Project totals for numbers of wells, miles of roads/pipelines, and numbers of facilities have been broken down by federal, state and private surface land categories for analysis purposes only. These totals represent a rough estimate based on conceptual locations of surface facilities and infrastructure.

1 Residual disturbance calculations are based on the assumption that interim reclamation would be initiated and successful.
2 Initial disturbance assumes that a 100-foot wide disturbance corridor would be needed for construction, of which 40 feet would be used for new road construction and 60 feet for pipeline/utility line installation.
3 Initial disturbance assumes that a 70-foot wide disturbance corridor would be needed for construction, of which 10 feet would be used for general road improvements and 60 feet for pipeline/utility line installation.
4 Initial disturbance assumes that a 60-foot wide disturbance corridor would be needed for pipeline/utility line installation within new and existing road ROWs.
5 Residual disturbance assumes that 35-foot wide portion of the original 60-foot wide disturbance corridor would be reclaimed leaving a 25-foot wide corridor for the long-term pipeline/utility corridor.
6 Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each.
7 Includes seven new and six expanded water treatment and injection facilities.
8 Numbers are rounded to the nearest whole number.

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2.3.1 Alternative-specific Activities

2.3.1.1 Well Pad Construction

Under the Proposed Action, Newfield proposes to construct and develop an additional 5,750 wells consisting of 750 Green River oil wells on 40-acre surface and downhole spacing (to be eventually converted to injection wells for waterflood recovery), 2,500 Green River oil wells on 20-acre downhole spacing that would be drilled from existing and/or proposed 40-acre surface spaced Green River oil well pads, and 2,500 vertical deep gas wells on 40-acre surface and downhole spacing. With associated cut and fill slopes, Green River oil wells on 40-acre surface and downhole spacing would be constructed to average dimensions of approximately 250 x 350 feet (2-acres in size), while vertical deep gas wells on 40-acre surface and downhole spacing will be constructed to average dimensions of approximately 300 x 425 feet (3-acres in size). Where the 2,500 Green River oil wells on 20-acre downhole spacing would be drilled and co-located on existing or proposed well pads, it is assumed for the purposes of analysis that each of these pads would be expanded by approximately 0.2 acres. Therefore, the initial surface disturbance resulting from the construction of all 5,750 wells would be approximately 9,500 acres (see **Table 2.3-1**). This would include approximately 1,500 acres for the 750 Green River oil wells on newly constructed well pads, 500 acres for the 2,500 Green River oil wells on existing well pads, and 7,500 acres for the 2,500 vertical deep gas wells on newly constructed well pads. Following well completion activities, portions of each well pad not needed for production operations would be reclaimed according to specifications of the BLM or UDOGM as appropriate. Therefore, long-term disturbance associated with construction of the 5,750 well pads would be reduced from approximately 9,500 acres to 3,750 acres, following successful interim reclamation.

2.3.1.2 Access Road Construction

Additional surface disturbance could occur along existing access where site-specific upgrades or improvements could require up to 10 feet of additional expansion or modification of the existing road corridor. Under the Proposed Action, approximately 363 miles of existing roads within the MBPA would require some level of expansion and/or upgrades to accommodate increased oil and gas activity and to install pipeline and utility line corridors adjacent to the existing roads (see **Sections 2.2.2.3** and **2.2.2.4**). In addition, approximately 243 miles of new access road would be constructed on BLM, State, and private lands. Nearly all of the new access roads would be paralleled by pipelines (i.e., co-located roads and pipelines). Existing roads that would need upgrades or expansion and conceptual locations for proposed roads are illustrated on **Figure 2-1 (Attachment 1)**.

Existing road ROWs would require an expansion width of approximately 70 feet; 10 feet of which would be needed for general road improvements, and the remaining 60 feet would be used for the installation of pipelines and utility lines. Because surface pipelines and utility lines would typically be constructed on one side of the road and buried pipelines and utilities constructed on the opposite side of the road, these analyses assume that surface disturbance due to pipelines and other utilities that are co-located with roads would average 60 feet wide. Therefore, the initial surface disturbance resulting from expansion and/or upgrades to existing roads and associated pipeline and utility line corridors would be approximately 1,618 acres, which includes an estimated 440 acres for road expansion and/or upgrades and 1,178 acres for pipeline and utility line installation. Following construction activities, a 35-foot wide portion of the initial 60-foot width disturbance corridor for pipelines and utility lines not needed for operational activities would be reclaimed. This would leave a 25-foot width for the long-term ROW, which would reduce the long-term disturbance associated with new roads co-located with pipelines to 1,618 acres.

Where new co-located roads and buried pipeline/utility lines are proposed, an initial 100-foot wide disturbance width would be needed for construction purposes. Of the initial 100-foot wide disturbance corridor, a 40-foot width would be used for road construction, and a 60-foot width would be used for the installation of pipelines and utility lines. Therefore, the initial surface disturbance resulting from the construction of new access roads and associated pipeline and utility line corridors would be approximately 6,025 acres, which includes an estimated 1,618 acres for access roads and 4,407 acres for pipeline and utility line installation. Following construction activities, a 35-foot wide portion of the initial 60-foot width disturbance corridor for pipelines not needed for operational activities would be reclaimed. This would leave a 25-foot width for the long-term ROW, which would reduce the long-term disturbance associated with new roads co-located with pipelines to 1,836 acres.

2.3.1.3 Pipeline Construction

Under the Proposed Action, the existing pipeline gathering system within the MBPA would be expanded to convey oil and gas production volumes from proposed wells. This expansion would be accomplished both by installing pipelines within new pipeline corridors and by installing additional pipelines within or adjacent to existing pipeline corridors. In most instances, gathering pipelines, fuel system pipelines, water injection pipelines, and produced water pipelines would be installed parallel to and/or within access road ROWs unless precluded by topography, county regulations (if installed adjacent to county-maintained roads), or gathering system constraints.

As previously addressed in **Section 2.3.1.2**, approximately 243 miles of pipeline would be installed adjacent to proposed access roads (co-located), and approximately 363 miles of pipeline would be installed along existing roads. Existing road corridors would require an expansion width of approximately 70 feet; 60 feet of which would be used for the installation of pipelines and utility lines, and the remaining 10 feet would be used for general road improvements (see **Sections 2.2.2.3** and **2.2.2.4**). Installation of proposed pipelines along existing roads would result in approximately 2,640 acres of initial surface disturbance. Following construction activities, a 35-foot wide portion of the initial 60-foot width disturbance corridor for pipelines not needed for operational activities would be reclaimed. This would leave a 25-foot width for the long-term ROW, which would reduce the long-term disturbance associated with pipelines co-located with existing roads to 1,100 acres. As indicated in **Section 2.2.2.2**, in limited situations, a proposed pipeline would be installed independent of an access road (i.e., cross-country). Under Alternative A, an estimated 60 miles of cross-country pipeline could be installed. Based on a 50-foot wide ROW, cross-country pipelines could result in approximately 366 acres of surface disturbance. As there are no conceptual locations for cross-country pipelines they are not shown on maps for Alternative A, nor are they included in the GIS-based disturbance calculation tables.

Where pipeline/utility lines are proposed for co-location with new roads, an initial 100-foot disturbance width would be needed for construction purposes. Of the initial 100-foot disturbance width, a 60-foot width would be used for the installation of pipelines and utility lines, and a 40-foot width would be used for road construction (see **Sections 2.2.2.3** and **2.2.2.4**). Installation of proposed pipeline along new roads would result in approximately 1,767 acres of initial surface disturbance. Following construction activities, a 35-foot wide portion of the initial 60-foot disturbance width for pipelines not needed for operational activities would be reclaimed. This would leave a 25-foot width for the long-term ROW, which would reduce the long-term disturbance associated with pipelines co-located with new roads to 736 acres.

2.3.1.4 Compressor Stations

Under the Proposed Action, Newfield would expand the current compressor system to accommodate expanded gas production from both oil and deep gas wells within the MBPA. This expansion would be achieved by adding new compressor stations and upgrading existing stations with larger capacity units. To accommodate expanded production at the deep gas wells, Newfield would construct 20 new compressor stations. Each new compressor station would occupy a site approximately 10 acres in size and could include up to 8,000-hp of compression. For associated gas produced with the Green River oil wells, Newfield would expand three existing compressor stations and construct 21 new compressor stations (see conceptual compressor station locations on **Figure 2-1 - Attachment 1**). Existing compressor stations for the Green River wells would be expanded by approximately 5 acres each to accommodate additional facilities that would include up to 5,000-hp of additional compression. The new compressor station would occupy a site approximately 10 acres in size and would include up to 8,000- hp of compression. Therefore, the initial surface disturbance resulting from the construction of 21 new compressor stations and expansion of three existing stations would be approximately 225 acres, which includes an estimated 210 acres for new compressor stations and 15 acres for expansion of existing facilities. The combined total compression of these facilities within the MBPA would be approximately 183,000 hp.

Central facilities, including the compressor stations would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 255 acres.

2.3.1.5 Central Gas Processing Plant

The conceptual location for the proposed gas processing plant is the same under all of the action alternatives and is illustrated on **Figure 2-1 (Attachment 1)**. Construction of the proposed gas processing plant would require the disturbance of approximately 10 acres.

Central facilities, including the proposed gas processing plant would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 10 acres.

2.3.1.6 Water Treatment and Injection Facilities

Under the Proposed Action, Newfield would construct seven new and expand six existing water treatment and injection facilities within the MBPA. The proposed water treatment facilities would be used for recycling of produced water that would either be co-mingled with fresh water and piped for waterflood injection wells, or trucked from the facility to be used at subsequent wells for completion activities.

Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each. Therefore, the initial surface disturbance resulting from the construction of seven new water treatment and injection facilities and expansion of six existing facilities would be approximately 86 acres.

As with other central facilities, water treatment and injection facilities would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 86 acres.

2.3.1.7 Gas and Oil Separation Plants (GOSPs)

Under the Proposed Action, Newfield would construct up to 12 new GOSPs that would be used for the initial separation of produced water and gas from the oil prior to shipment to the refinery for further processing. Conceptual locations for proposed GOSPs are illustrated on **Figure 2-1 (Attachment 1)**. Each new GOSP would occupy a site approximately 22 acres in size. Therefore, the initial surface disturbance resulting from the construction of proposed GOSPs within the MBPA would be approximately 264 acres.

As with other production facilities, GOSPs would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 264 acres.

2.3.1.8 Pump Stations

Under the Proposed Action, Newfield would construct up to six water pump stations, which would boost pressure to ensure consistent delivery of fresh and produced water to the water treatment and injection facilities within the MBPA. Each new pump station would occupy a site approximately 3 acres in size, which would result in a total surface disturbance of 18 acres.

As with other production facilities, initial surface disturbance associated with the construction of pump stations would not be reclaimed during interim reclamation because the entire disturbed area would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 18 acres.

2.3.2 Well Drilling

Under the Proposed Action, Newfield proposes to drill up to 5,750 oil and gas wells to the Green River Formation, of which 750 wells would be vertically drilled on a 40-acre downhole spacing pattern and 2,500 wells would be directionally or horizontally drilled on a 20-acre downhole spacing pattern. In addition, Newfield would drill 2,500 deep gas wells to the Green River, Wasatch, Mesaverde, Blackhawk/Mancos, and/or Frontier/Dakota formations on a 40-acre downhole spacing pattern. The Green River oil wells would be drilled to a total depth of between 4,500 and 6,500-feet bgs, and the proposed deep gas wells would be drilled to a total depth of between 13,000 and 18,000-feet bgs, depending on the specific depth of the target formation. Of the 5,750 wells drilled under the Proposed Action, approximately 4,902 would be drilled on Federal Lands; 686 would be drilled on State lands; and 162 wells would be drilled on Private land (see **Table 2.3-1**). Note that numbers of wells have been broken down by federal, state and private surface land categories for analysis purposes only, and could change based on site-specific conditions.

Based upon current technology and drilling rates in the MBPA, up to 12 drilling rigs could be active in the MBPA at any given time. Depending on the type of well drilled (i.e., Green River oil well or deep gas well), an average of 360 wells would be drilled annually. Also, based on the amount of days needed to drill a deep gas well, the timeframe to fully explore and develop the resource may need to be extended up to 30 years. The continued deep gas exploration program may or may not be initiated immediately upon the start of the proposed project, and would be dependent on current and near-term commodity pricing for natural gas.

2.3.3 Interim Reclamation

Under the Proposed Action, approximately 8,321 acres of initial disturbance (52 percent) associated with construction of proposed well pads, road and pipeline ROWs, and other project facilities not needed for operational purposes would be reclaimed. This would reduce the long-term disturbance associated with implementation of the Proposed Action to approximately 7,808 acres.

2.3.4 Water Requirements

A breakdown of water requirements for well drilling and completion, dust suppression, and waterflooding operations under the Proposed Action is presented in **Table 2.3.4-1**.

Table 2.3.4-1. Water Requirements for Well Drilling and Completion, Dust Suppression, and Waterflooding Operations under the Proposed Action

Activity/Phase	Number of Wells	Amount of Water Required per Well (acre-feet)	Total Water Use (acre-feet)	Annual Water Use (acre-feet)
Well Drilling and Completion[1]				
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	750	0.9	675	42*
New Green River Oil Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	2,500	0.9	2,250	141*
New Deep Gas Well Pads on 40-Acre Surface and Downhole Spacing	2,500	6.2	15,500	967*
Subtotal for the 16-year active well drilling and completion period	**5,750**	**--**	**18,425**	**1,150***
Dust Suppression				
Construction of New Well Pads and Associated Roads and Pipeline/Utility Corridors	575	0.08[2]	46	3
Subtotal for the 16-year active well drilling and completion period	**575**	**--**	**46**	**3**
Operation of New Well Pads and Associated Roads and Pipeline/Utility Corridors	575	0.13[3]	1,500 - 2,250[4]	75
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**1,500 - 2,250**	**75**

Activity/Phase	Number of Wells	Amount of Water Required per Well (acre-feet)	Total Water Use (acre-feet)	Annual Water Use (acre-feet)
Waterflooding Infrastructure and Operations				
Conversion of up to 750 Proposed Wells to Injection Wells	750	0.01[5]	54,760 – 82,140[6]	2,738[7]
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**54,760 – 82,140**	**2,738**
TOTAL	**--**	**--**	**74,731 – 102,861**	**3,966**

[1] Assumes a 16-year active well drilling and completion period.

[2] Approximately five water truck (approximately 650-bbls or 0.08 acre-feet) would be needed for dust suppression per new well pad, access road, and pipeline/utility corridor during construction activities, for approximately 10 percent of the proposed project (i.e., up to 575 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

[3] Approximately eight water truck (approximately 1000-bbls or 0.13 acre-feet) would be needed annually for dust suppression per new well pad, access road, and pipeline/utility corridor during project operation, for approximately 10 percent of the proposed project (i.e., up to 575 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

[4] Calculated based on 75.0 acre-feet annually over the 20- to 30-year construction and operational period.

[5] Assumes 0.01 acre-feet of water per well daily.

[6] Calculated based on 2,738 acre-feet annually over the 20- to 30-year construction and operational period.

[7] Based on a 20-year period during which producing wells would be converted to injection wells.

[*] Based on average annual water use.

Note: Summations may not total precisely due to rounding.

2.3.4.1 Drilling and Completion

An estimated average of 7,000 bbls (0.9 acre-feet) of water would be required to drill and complete an individual Green River oil well and up to 48,000 bbls (6.2 acre-feet) of water would be required to drill and complete a deep gas well. Water used during the drilling and completion phase at an individual well would be piped to the water treatment and injection facilities for treatment/recycling. Total water use for drilling and completion of all 5,750 wells under the Proposed Action would be approximately 18,425 acre-feet.

2.3.4.2 Dust Suppression

For purposes of analysis in this EIS, Newfield assumes that approximately five water truck equivalents (approximately 650 bbls or 0.08 acre-feet) would be needed for dust suppression per new well pad, associated access road, and pipeline/utility corridor during construction activities, for approximately 10 percent of the proposed project (i.e., for approximately 575 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities). Therefore, based on these assumptions, Newfield would use a total of approximately 46 acre-feet of water for dust suppression during construction activities under the Proposed Action.

In addition, approximately 1,000 bbls (0.13 acre-feet) of water would be needed annually for dust suppression per well pad, associated access road, and pipeline/utility corridor during project operation, again for approximately 10 percent of the proposed project (i.e., for approximately 575 well pads and their associated roads, pipeline/utility corridors, and other surface facilities). Based on these assumptions, implementation of the Proposed Action would require approximately 75 acre-feet of water per year for dust abatement during project operations.

2.3.4.3 Waterflooding Infrastructure and Operations

Newfield would use waterflooding technology on all of the proposed 40-acre spaced Green River wells (i.e., approximately 750 wells) after about the first 3 years of production. A total of approximately 75 to 100 bbls per day (bpd), or approximately 0.01 acre-feet per day, of water would be required for each waterflood injection well under the Proposed Action. Newfield would convert approximately 750 of their proposed wells to injection wells, therefore requiring approximately 7.5 acre-feet of fresh and produced water per day for injection purposes. Based on the requirement of 7.5 acre-feet of water per day, the annual water requirement for waterflooding operations would be approximately 2,738 acre-feet.

2.3.5 Produced Water Disposal

Under the Proposed Action, seven new and six expanded water treatment and injection facilities, and three water disposal wells could be constructed. As previously noted in **Section 2.3.1.6**, surface disturbance from the proposed water management facilities would be approximately 86 acres. Surface disturbance from construction and drilling of the water disposal wells is included in the surface disturbance summarized for well pads. In addition, up to six pump stations would be constructed under the Proposed Action, disturbing a total of approximately 18 acres.

Water disposal wells would be drilled in the MBPA on existing well pads or using existing well borings. Assuming an average disposal capacity of 4,000 barrels of water per day (BWPD) for each disposal well, the three new disposal wells would have a combined capacity of 12,000 BWPD. Although future water production is difficult to predict because of variable water saturation conditions as the oil and gas formations are produced and depleted, it is estimated for purposes of analysis in this EIS that Newfield will recycle nearly all of the water that would be produced under the Proposed Action for use in waterflood operations.

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 acres of new disturbance to an existing well pad, for a total maximum new surface disturbance of 0.6 acres.

2.3.6 Workforce Requirements

The active workforce needed to develop the Proposed Action is shown in **Table 2.3.6-1**.

Table 2.3.6-1. Estimated Workforce Requirements under the Proposed Action

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Construction and Installation						
Access Road	4 days/mile	606 miles	8	19,392	1,212	5

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Well Pad	3 days/site	5,750	8	138,000	8,625	36
Pipelines	10 days/mile	606 miles	10	60,600	3,788	16
Drilling and Casing	4 days/well	5,750	8	184,000	11,500	48
Well Completion	4 days/well	5,750	20	460,000	28,750	120
Well Production	10 days/well	5,750	16	920,000	57,500	240
Central Facilities	45 days/site	57	20	51,300	3,206	13
Total				**1,833,292[1]**	**114,581**	**478**
Operation and Maintenance						
Road/Well Pad Maintenance	120 days/year	N/A	3	12,600	360	2
Pumpers	260 days/year	N/A	36	327,600	9,360	39
Office	260 days/year	N/A	4	36,400	1,040	4
Well Workover	5 days/well	30 per year	2	10,500	310	1
Total				**387,100[2]**	**11,070**	**46**
Reclamation and Abandonment[3]						
Wells	3 days/well pad	5,750	4	69,000	N/A	--
Roads and Pipelines	4 day/mile	606 miles	4	9,696	N/A	--
Central Facilities	30 day/facility	57	16	27,360	N/A	--
Total				**106,056**	--	--

1 Based on a 16-year construction schedule.
2 Based on a 35-year construction, production, and operation schedule.
3 Includes interim reclamation.

2.4 ALTERNATIVE B – NO ACTION

Under the No Action Alternative, the proposed oil and gas infill development project on public land surface and/or federal mineral estates as described in the Proposed Action would not be implemented. However, proposed oil well development would likely continue on State and private lands or minerals within the MBPA, subject to the approval of UDOGM and/or the appropriate private land owner. This EIS evaluates proposed development on State and private lands or minerals under the No Action alternative (and all alternatives) but the BLM does not have jurisdiction over State and private land or minerals. Therefore, the ROD for this EIS will not include decisions specific to State and private lands or minerals. Reasonable access across BLM-administered surface to proposed well pads and facilities on

State and private lands or minerals could also occur under the No Action Alternative, as allowed by Federal regulations. Development, production, and maintenance activities for wells approved under the August 2005 ROD for the Castle Peak and Eight Mile Flat Oil and Gas Expansion EIS would also continue on BLM-administered lands. Activities and project components on federal lands discussed in the No Action Alternative are not unique to Newfield's Proposed Action as analyzed in this DEIS. Those activities and components either have been analyzed in prior NEPA documents or will be analyzed in future NEPA documents.

A summary of surface disturbance associated with implementation of the No Action Alternative is presented in **Table 2.4-1**. This includes development approved through other NEPA documents or approved by other agencies but not yet constructed as of December 31, 2011 (see **Table 2.4-2**), plus conceptual facilities on State and private surface land. The "as of" December 31, 2011 date footnoted under **Table 2.4-2** 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 Proposed Action and alternatives.

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Table 2.4-1. Surface Disturbance under the No Action Alternative

Project Feature	Size (disturbance width [feet] or acres/facility)	Federal Lands			State Lands			Private Lands			Project Total		
		Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]
Well Pads													
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	2.0 acres	0	0	0	107	214	107	21	42	21	128	256	128
New Green River Oil and/or Deep Gas Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	0.2 acres	0	0	0	295	59	59	124	25	25	419	84	84
Wells Remaining to be Drilled under other Approved or Proposed Newfield Projects	0.2 acres[2]	241	48	48	0	0	0	0	0	0	241	48	48
Subtotal	**--**	**241**	**48**	**48**	**402**	**273**	**166**	**145**	**67**	**46**	**788**	**388**	**260**
Access Roads													
New Roads Co-located with Pipelines	40 feet[3]	0 miles	0	0	21 miles	102	102	2.5 miles	12	12	23.5 miles	114	114
Existing Roads Co-located with New Pipelines	10 feet[4]	1.5 miles	2	2	30.5 miles	37	37	13 miles	16	16	45 miles	55	55
Subtotal	**--**	**1.5 miles**	**2**	**2**	**51.5 miles**	**139**	**139**	**15.5 miles**	**28**	**28**	**68 miles**	**169**	**169**
Pipelines													
Pipelines Co-located with New Roads	30 feet[5]	0 miles	0	0[6]	21 miles	76	51[6]	2.5 miles	9	6[6]	23.5 miles	85	57[6]
Pipelines Co-located with Existing Roads	30 feet[5]	1.5 miles	5.5	3.5[6]	30.5 miles	111	74[6]	13 miles	47	31.5[6]	45 miles	164	109[6]
Subtotal	**--**	**1.5 miles**	**5.5**	**3.5**	**51.5 miles**	**187**	**125**	**15.5 miles**	**56**	**37**	**68 miles**	**249**	**166**
Central Facilities[7]													
Compressor Stations (New and Upgrades)	10.0 acres	2	20	20	0	0	0	0	0	0	2	20	20
Gas Processing Plants	10.0 acres	0	0	0	1	10	10	0	0	0	1	10	10
Water Treatment and Injection Facilities	7.0 acres	0	0	0	1	7	7	0	0	0	1	7	7
Gas and Oil Separation Plants (GOSPs)	22.0 acres	0	0	0	1	22	22	0	0	0	1	22	22
Fresh Water Collector Well	1.7 acres	1	0	0	0	0	0	0	0	0	1	1.7	.7
Pump Stations	5.0 acres	0	0	0	1	5	5	0	0	0	1	5	5
Subtotal	**--**	**0**	**20**	**20**	**4**	**44**	**44**	**0**	**0**	**0**	**7**	**64**	**64**
Total New Disturbance	**--**	**--**			**--**			**--**			**--**	**870**	**659**

Source Note: Project totals for numbers of wells, miles of roads/pipelines, and numbers of facilities have been broken down by federal, state and private surface land categories for analysis purposes only. These totals represent a rough estimate based on conceptual locations of surface facilities and infrastructure.

1 Residual disturbance calculations are based on the assumption that interim reclamation will be initiated and successful.
2 For purposes of analysis, approximately half of the wells are assumed to be vertical wells drilled on existing well pads and half are assumed to be vertical wells drilled on new 2-acre well pads.
3 Initial disturbance assumes that a 70-foot wide disturbance corridor would be needed for construction, of which 40 feet would be used for new road construction and 30 feet for pipeline installation.
4 Initial disturbance assumes that a 40-foot wide disturbance corridor would be needed for construction, of which 10 feet would be used for general road improvements and 30 feet for pipeline installation.
5 Initial disturbance assumes that a 30-foot wide disturbance corridor would be needed for pipeline installation within new and existing road ROWs in the absence of utility lines.
6 Residual disturbance assumes that a 10-foot wide portion of the original 30-foot wide disturbance corridor would be reclaimed leaving a 20-foot wide corridor for the long-term pipeline corridor.
7 Central facilities would not likely be constructed on federal surface under the No Action alternative. However, for the purposes of consistent analysis amongst the alternatives the facilities are conceptually shown on federal surface.

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Table 2.4-2. Previously Approved and Planned Oil and Natural Gas Development Projects on BLM-Administered Lands in the MBPA under the No Action Alternative

Project	Development Approved	Number of Wells Drilled and in Production	Number of Wells Remaining to be Drilled and Placed in Production under the Castle Peak EIS and MDP EAs[1]
Castle Peak and Eight Mile Flat Oil and Gas Expansion EIS	778[2]	560	218
Other NEPA[3]	23	--	23
Total	**801**	**560**	**241[1]**

1 As of December 31, 2011.
2 Although 923 wells were assessed in the Castle Peak and Eight Mile Flat EIS (with 150 of those planned for conversion to waterflood injection for a net of 823 producing wells) the August 2005 ROD approved a net of only 778 producing wells.
3 Other NEPA includes approved Master Development Plans (MDPs) Number 17 through 22 and 25. MDPs 17 through 22 and 25 authorized a total of 146 wells; however, only 23 of those wells are outside of the Castle Peak Project Area.

Based on the projects presented in **Table 2.4-2**, it is estimated that approximately 241 wells remain to be drilled on BLM-administered lands in addition to the 3,395 existing wells within the MBPA (as of December 31, 2011).

In addition to the approved 241 wells that have not yet been drilled, an additional approximately 547 oil and gas wells would be developed on State and private lands or minerals in the MBPA under the No Action Alternative, for a total of 788 producing wells. Newfield proposes to drill wells at an average rate of up to 360 wells per year. Under this drilling scenario, construction, drilling, and completion of all 788 wells would occur over an approximately 2.2-year period. The total number of wells drilled would depend largely on outside factors such as production success, engineering technology, reservoir characteristics, economic factors, commodity prices, rig availability, and lease stipulations. The anticipated life of an individual well is 20 to 30 years, and the anticipated time it would take for field abandonment and final reclamation is 5 years. Therefore, the anticipated LOP under the No Action Alternative would be approximately 28 to 38 years.

Conceptual locations for the approximately 788 wells on Federal, State, and private lands are illustrated on **Figure 2-2 (Attachment 1)**. Development methods on State and private lands or minerals would be essentially identical to those used to develop wells on BLM-administered lands, subject to UDOGM or private landowner requirements.

Key components of the No Action Alternative include the following (see **Figure 2-2 – Attachment 1)**:

- Development of up to 128 Green River oil wells on 40-acre surface and downhole spacing drilled from new 2-acre well pads, all of which would eventually be converted into waterflood injection wells;
- Development of up to 419 Green River oil wells and/or deep gas wells on 20-acre downhole spacing that would be vertically, directionally, or horizontally drilled from existing and/or

proposed 40-acre surface spaced Green River oil well pads with average surface disturbance of about 0.2 acres per pad;

- Development of up to 241 additional Green River oil wells from other previously approved and planned Newfield oil and natural gas development projects. For purposes of analysis, approximately half of the wells are assumed to be vertical wells drilled on existing well pads and half are assumed to be vertical wells with average surface disturbance of about 0.2 acres per pad;
- Construction of approximately 23 miles of new 70-foot wide ROW that would be used for new road construction (40-foot width) and pipeline installation (30-foot width).
- Construction of approximately 45 miles of 70-foot wide ROW that would be used for up to 40-foot wide expansion of existing access road ROW for co-located road upgrade (10-foot width) and pipeline installation (30-foot width); ;
- Construction of up to two (2) new 8,000 hp compressor stations;
- Construction of a 50 MMscf/d centralized Green River oil well gas processing plant;
- Construction of one new water treatment and injection facilities for management and distribution and injection of produced water;
- Construction of one new GOSP for oil and produced water collection; and
- Construction of one water pump station.

Surface disturbance anticipated under the No Action Alternative is shown in **Table 2.4-1**. Initial surface disturbance would occur during and immediately after the construction, drilling, completion, and testing activities. Prior to interim reclamation, initial surface disturbance for well pads, access roads, pipeline ROWs, and other surface facilities would equal approximately 870 acres. Those portions of the well pads, access road ROWs, pipeline ROWs, and other facilities not needed for production operations would be reclaimed within two to three growing seasons assuming optimal conditions are present. The remaining surface disturbance would be residual or “long-term” disturbance of approximately 659 acres for the 28 to 38-year LOP.

Specific details of construction-related activities and specific design features for well drilling and completion; production, operations, and maintenance activities; final reclamation and abandonment; and hazardous materials and solid waste under the No Action Alternative are identical to those previously described in **Section 2.2**, *Development Activities Common to All Action Alternatives* and will not be repeated further in this section. Specific details of project activities, specific design features, and surface disturbance summaries that are unique to the No Action Alternative are described below in the following sections.

2.4.1 Alternative-specific Activities

2.4.1.1 Well Pad Construction

Under No Action Alternative, Newfield would construct and develop an additional 547 wells consisting of 128 Green River oil wells on 40-acre surface and downhole spacing (to be eventually converted to injection wells for waterflood recovery) and 419 Green River oil wells and/or deep gas wells on 20-acre downhole spacing that would be drilled from existing and/or proposed 40-acre surface spaced Green River oil well pads. Where the 419 Green River oil wells and/or deep gas wells on 20-acre downhole spacing would be drilled and co-located on existing or proposed well pads, it is assumed for the purposes of analysis that these pads would require an enlargement of 0.2 acres each.

Newfield would also develop an additional 241 oil and gas wells from other previously approved and planned projects. For purposes of analysis, approximately half of the wells are assumed to be vertical wells drilled on existing well pads and half are assumed to be vertical wells drilled on new 2-acre well pads. Therefore, the initial surface disturbance resulting from the construction of all 788 wells (547 wells on State and private surface land and 241 wells from other previously approved and planned projects) would be approximately 388 acres (see **Table 2.4-1**). This would include approximately 256 acres for the 128 Green River oil wells constructed on new well pads, 84 acres for the new Green River oil wells and/or deep gas wells constructed on existing well pads, and 48 acres for the vertical oil and gas wells from other previously approved and planned projects. Following well completion(s), portions of the well pad not needed for production would be reseeded and reclaimed according to specifications of the appropriate SMA. Assuming successful interim reclamation, long-term well pad disturbance under the No Action alternative would be reduced to approximately 260 acres.

2.4.1.2 Access Road Construction

Implementation of the No Action Alternative would require the construction of up to 23 miles of new access roads and expansion and/or upgrades to approximately 45 miles of existing roads on State and private surface lands. ROWs and surface corridor widths for roads under the No Action Alternative would be similar to those described in **Section 2.3.1.2**. Therefore, the initial surface disturbance resulting from the construction of new access roads and expansion and/or upgrades to existing roads would be approximately 114 and 55 acres, respectively.

2.4.1.3 Pipeline Construction

Under the No Action Alternative, approximately 23 miles of pipeline would be installed adjacent to proposed access roads (co-located) and approximately 45 miles of pipeline would be installed along existing roads (see **Table 2.4-1)**. ROWs and surface corridor widths for pipelines under the No Action Alternative would be less than those in the action alternatives because a fewer number of individual pipelines would be installed within the ROW under this alternative. Therefore, under the No Action Alternative, approximately 30 feet would be needed for the installation of pipelines. Following construction activities, a 10-foot wide portion of the initial 30-foot width disturbance corridor for pipelines not needed for operational activities would be reclaimed. The residual long-term disturbance associated with these facilities would be 57 and 109 acres for pipelines co-located along new and existing roads, respectively. As indicated in **Section 2.2.2.2**, in limited situations, a proposed pipeline would be installed independent of an access road (i.e., cross-country). Under Alternative B, an estimated 6 miles of cross-country pipeline could be installed. Based on a 50-foot wide ROW, cross-country pipelines could result in approximately 36 acres of surface disturbance. As there are no conceptual locations for cross-country pipelines they are not shown on maps for Alternative B, nor are they included in the GIS-based disturbance calculation tables.

2.4.1.4 Compressor Stations

Under the No Action Alternative, Newfield would construct up to two new compressor stations within the MBPA. Each compressor station would occupy a site approximately 10 acres in size and could include up to 8,000 hp of compression. Therefore, the initial surface disturbance resulting from the construction of the two new compressor stations would be approximately 20 acres.

Central facilities, including the compressor stations, would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 20 acres.

2.4.1.5 Central Processing Plant

The conceptual location for the proposed gas processing plant is the same under all of the action alternatives and is illustrated on **Figure 2-3 (Attachment 1)**. Construction of the proposed gas processing plant would require the disturbance of approximately 10 acres.

Central facilities, including the proposed central gas processing plant, would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 10 acres.

2.4.1.6 Water Treatment and Injection Facilities

Under the No Action Alternative, Newfield would construct one (1) new treatment and injection facility within the MBPA. The water treatment and injection facility would occupy a site approximately 7 acres in size.

As with other central facilities, water treatment and injection facilities would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 7 acres.

2.4.1.7 Gas and Oil Separation Plants (GOSPs)

Under the No Action Alternative, Newfield would construct one new GOSP that would be used for the initial separation of produced water and gas from the oil prior to shipment to the refinery for further processing. The new GOSP would occupy a site approximately 22 acres in size.

As with other central facilities, GOSPs would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 22 acres.

2.4.1.8 Pump Stations

Under the No Action Alternative, Newfield would construct one water pump station, which would boost pressure to ensure consistent delivery of fresh and produced water to the water treatment and injection facilities within the MBPA. The new pump station would occupy a site approximately 5 acres in size.

As with other central facilities, initial surface disturbance associated with the construction of pump stations would not be reclaimed during interim reclamation because the entire disturbed area would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 5 acres.

2.4.2 Well Drilling

Under the No Action Alternative, Newfield would construct and develop approximately 547 oil and gas wells on State and private lands in the MBPA. An additional 241 wells would be constructed on Federal, State, and private lands under other previously approved and planned projects. Of the 788 total wells drilled under the No Action Alternative, 241 would be drilled on Federal Lands, approximately 402 would be drilled on State lands, and 145 wells would be drilled on Private land (see **Table 2.4-1**). Numbers of wells have been broken down by federal, state, and private surface land categories for analysis purposes only.

Based upon current technology and drilling rates in the MBPA, up to five drilling rigs could be active in the MBPA at any given time. Depending on the type of well drilled (i.e., Green River oil well or deep gas well), an average of 360 wells would be drilled annually. Also, based on the amount of days needed to drill a deep gas well, the timeframe to fully explore and develop the resource may need to be extended. The continued deep gas exploration program may or may not be initiated immediately upon the start of the proposed Project, and would be dependent on current and near-term commodity pricing for natural gas.

2.4.3 Interim Reclamation

Under the No Action Alternative, approximately 211 acres of initial disturbance (24 percent) associated with construction of proposed well pads, road and pipeline ROWs, and other project facilities not needed for operational purposes would be reclaimed. This would reduce the long-term disturbance associated with implementation of the No Action Alternative to approximately 659 acres.

2.4.4 Water Requirements

A breakdown of water requirements for well drilling and completion, dust suppression, and waterflooding operations under the No Action Alternative is presented in **Table 2.4.4-1**.

Table 2.4.4-1. Water Requirements for Well Drilling and Completion, Dust Suppression, and Waterflooding Operations under the No Action Alternative

Activity/Phase	Number of Wells	Amount of Water Required per Well (acre-feet)	Total Water Use (acre-feet)	Annual Water Use (acre-feet)
Well Drilling and Completion[1]				
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	128	0.9	115	52*
New Green River Oil and/or Deep Gas Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	419	0.9	377	171*

Activity/Phase	Number of Wells	Amount of Water Required per Well (acre-feet)	Total Water Use (acre-feet)	Annual Water Use (acre-feet)
Wells Remaining to be Drilled under other Approved or Proposed Newfield Projects	241	0.9	217	99
Subtotal for the 2.2-year active well drilling and completion period	**788**	**--**	**709**	**322***
Dust Suppression				
Construction of New Well Pads and Associated Roads and Pipeline/Utility Corridors	78	0.08[2]	6	4
Subtotal for the 2.2-year active well drilling and completion period	**--**	**--**	**6**	**4**
Operation of New Well Pads and Associated Roads and Pipeline/Utility Corridors	78	0.13[3]	203 - 304[4]	10
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**203-304**	**10**
Waterflooding Infrastructure and Operations				
Conversion of up to 150 Proposed Wells to Injection Wells	150	0.01[5]	10,950 – 16,425	548[6]
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**10,950 – 16,425**	**548**
TOTAL	**--**	**--**	**11,868 – 17,444**	**884**

1 Assumes a 2.2-year active well drilling and completion period.

2 Approximately five water truck (approximately 650-bbls or 0.08 acre-feet) would be needed for dust suppression per new well pad, access road, and pipeline/utility corridor during construction activities, for approximately 10 percent of the proposed project (i.e., up to 78 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

3 Approximately eight water truck (approximately 1000-bbls or 0.13 acre-feet) would be needed annually for dust suppression per new well pad, access road, and pipeline/utility corridor during project operation, for approximately 10 percent of the proposed project (i.e., up to 78 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

4 Calculated based on 10 acre-feet annually over the 20- to 30-year construction and operational period.

5 Assumes 0.01 acre-feet of water per well daily.

6 Based on a 20-year project period during which producing wells would be converted to injection wells.

* Based on average annual water use.

Note: Summations may not total precisely due to rounding.

2.4.4.1 Drilling and Completion

An estimated average of 7,000-bbls (0.9 acre-feet) of water would be required to drill and complete an individual Green River oil well or a deep gas well. Water used during the drilling and completion phase at an individual well would be piped to the water treatment and injection facilities for treatment/recycling. Total water use for drilling and completion of all 788 wells under the No Action Alternative would be approximately 709 acre-feet.

2.4.4.2 Dust Suppression

As with other action alternatives, it is assumed that water would be needed for dust suppression for approximately 10 percent of the proposed project during construction (i.e., for approximately 78 new well pads and their associated roads, pipeline corridors, and other surface facilities). Therefore, based on this assumption, Newfield would use a total of approximately 6 acre-feet of water for dust suppression during construction activities under the No Action Alternative.

Similarly, water would be needed annually for dust suppression per well pad, associated access road, and pipeline corridor during project operation, again for approximately 10 percent of the proposed project (i.e., for approximately 78 well pads and their associated roads, pipeline corridors, and other surface facilities). Based on these assumptions, implementation of the No Action Alternative would require 10 acre-feet of water per year for dust abatement during project operations.

2.4.4.3 Waterflooding Infrastructure and Operations

Newfield would use waterflooding technology on the 40-acre surface and downhole spaced Green River wells after about the first 3 years of production. A total of approximately 75 to 100 bpd (or approximately 0.01 acre-feet per day) of water would be required for each waterflood injection well. Under the No Action Alternative, Newfield would convert approximately 150 of their proposed wells to injection wells, therefore requiring approximately 1.5 acre-feet of fresh water per day for injection purposes. Based on the requirement of 1.5 acre-feet of water per day, the annual water requirement for waterflooding operations would be approximately 548 acre-feet.

2.4.5 Produced Water Disposal

Under the No Action Alternative, a single water treatment and injection facility would be constructed. Surface disturbance from the proposed water management facility would be approximately 7 acres. In addition, a single pump station would be constructed under the No Action Alternative, disturbing a total of approximately 5 acres.

Although estimated future water production is difficult to predict because of variable water saturation conditions as the oil and gas formations are produced and depleted, it is estimated for purposes of analysis in this EIS that Newfield will recycle all of the water that would be produced under this alternative for use in waterflood operations.

2.4.6 Workforce Requirements

The active workforce needed to implement the No Action Alternative is shown in **Table 2.4.6-1**.

Table 2.4.6-1. Estimated Workforce Requirements under the No Action Alternative

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Construction and Installation						
Access Road	4 days/mile	68 miles	8	2,176	989	5
Well Pad	3 days/site	778	8	18,672	8,487	36
Pipelines	10 days/mile	68 miles	10	6,800	3,091	13
Drilling and Casing	4 days/well	778	8	24,896	11,316	48
Well Completion	4 days/well	778	20	62,240	28,291	118
Well Production	10 days/well	778	16	124,480	56,582	236
Central Facilities	45 days/site	7	20	6,300	2,864	12
Total				**245,564**	**111,620**[1]	**468**
Operation and Maintenance						
Road/Well Pad Maintenance	120 days/year	N/A	3	10,080	360	2
Pumpers	260 days/year	N/A	16	116,480	4,160	18
Office	260 days/year	N/A	2	14,560	520	3
Well Workover	5 days/well	15 per year	2	4,200	150	1
Total				**145,320**	**5,190**[2]	**24**
Reclamation and Abandonment[3]						
Wells	3 days/well pad	778	4	9,336	N/A	--
Roads and Pipelines	4 day/mile	68 miles	4	1,088	N/A	--
Central Facilities	30 day/facility	7	16	3,360	N/A	--
Total				**13,784**	--	--

[1] Based on a 2.2-year construction schedule

[2] Based on a 28-year construction, production, and operation schedule.

[3] Includes interim reclamation.

2.5 ALTERNATIVE C – FIELD-WIDE ELECTRIFICATION

This alternative was developed in response to air quality issues raised during the public and agency scoping process. The principal component of this alternative entails a phased field-wide electrification system that would be integrated in the MBPA over an estimated 7-year period. This alternative would incorporate the same construction and operational components described in **Section 2.2**, except that gas-driven motors would be converted to electric motors as field electrification is phased into the MBPA.

Under Alternative C, the same number of oil and gas wells (5,750) would be developed on BLM, State, and private lands as described under the Proposed Action. Under this drilling scenario, construction, drilling, and completion of all 5,750 wells would occur for approximately 16 years. The total number of wells drilled would depend largely on outside factors such as production success, engineering technology, reservoir characteristics, economic factors, commodity prices, rig availability, and lease stipulations. The anticipated life of an individual well is 20 to 30 years, and the anticipated time it would take for field abandonment and final reclamation is 5 years. Therefore, the anticipated LOP under Alternative C would be 41 to 51 years. Conceptual locations for the approximately 5,750 wells, well pads, and other surface facilities are illustrated on **Figure 2-3 (Attachment 1)**.

Alternative C includes the following primary components (see **Figure 2-3 – Attachment 1**):

- Development of up to 750 Green River oil wells on 40-acre surface and downhole spacing drilled from new 2-acre well pads, all of which would be converted into waterflood injection wells after approximately 3 years of production;

- Development of up to 2,500 Green River oil wells on 20-acre downhole spacing that would be vertically, directionally, or horizontally drilled from existing and/or proposed 40-acre surface spaced Green River oil well pads, consistent with current State spacing requirements;

- Development of up to 2,500 vertical deep gas wells on 40-acre surface and downhole spacing drilled from new 3-acre well pads, which would be constructed adjacent to Green River oil well pads to reduce new surface disturbance and use existing utility infrastructure and access roads;

- Construction of approximately 243 miles of new 100-foot wide ROW that would be used for new road construction (40-foot width) and pipeline installation (60-foot width). Up to 70-foot wide expansion along approximately 363 miles of existing access road ROW that would be used for road upgrade (10-foot width) and pipeline installation (60-foot width);

- Construction of 20 new compressor stations for deep gas well development;

- Expansion of three existing Green River oil well compressor stations and construction of one new compressor station for gas associated with Green River oil well development;

- Construction of a 50 MMscf/d centralized gas processing plant;

- Construction of seven new and expansion of six existing water treatment and injection facilities for management and distribution and injection of produced water;

- Construction of up to 12 GOSPs for oil and produced water collection;

- Development of one fresh water collector well for waterflood operations;

- Construction of six water pump stations; and

- Phased field-wide electrification consisting of construction of approximately 34 miles of overhead, cross-country 69kV transmission line (pole line), 156 miles of distribution lines, and construction of 11 generating stations (also known as substations).

Surface disturbance anticipated under Alternative C is shown in **Table 2.5-1**. Initial surface disturbance would occur during and immediately after the construction, drilling, completion, and testing activities.

Prior to interim reclamation, initial surface disturbance for well pads, access roads, pipeline ROWs, and other surface facilities would equal approximately 16,308 acres. Those portions of the well pads, access road ROWs, pipeline ROWs, and other facilities not needed for production operations would be reclaimed within two to three growing seasons assuming optimal conditions are present. The remaining surface disturbance would be residual or "long-term" disturbance of approximately 7,926 acres for the 41 to 51-year LOP.

Specific details of construction-related activities and specific design features for the construction of well pads and roads, pipelines, compressor stations, GOSPs, and pump stations; well drilling and completion; production, operations, and maintenance activities; water requirements; produced water disposal; final reclamation and abandonment; and hazardous materials and solid waste for Alternative C are identical to those previously described under the Proposed Action and will not be repeated further in this section. Specific details of project activities, design features, and surface disturbance summaries that are unique to Alternative C are described below in the following sections.

2.5.1 Alternative Specific Activities

2.5.1.2 Phased Field-wide Electrification

Under Alternative C, a phased field-wide electrification system would be integrated in the MBPA. Installation would begin following project approval and would be completed over an estimated 7 years. Electrification would be used to power pumps at water treatment and injection facilities, pumps and heaters at GOSPs, compressors at central facilities, and separators and pump jacks at well site facilities.

Up to 11 generating stations (also known as substations) would be constructed in the MBPA and each would be fueled by natural gas that is extracted within the MBPA. Each generating station would consist of two 20-megawatt of electricity (MWe) gas turbine generators and one 10-MWe steam turbine generators capable of generating a combined 50-megawatt (MW) of power.

Each new generating station would occupy a site approximately 5 acres, therefore, the surface disturbance resulting from the construction of proposed generating stations within the MBPA would be approximately 55 acres. The combined total generating capacity of these facilities within the MBPA would be approximately 550MW of power. As with other central facilities, initial surface disturbance associated with the construction of generating stations would not be reclaimed during interim reclamation because the entire disturbed area would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 55 acres.

Table 2.5-1. Surface Disturbance under Alternative C

Project Feature	Size (disturbance width [feet] or acres/facility)	Federal Lands			State Lands			Private Lands			Project Total		
		Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]
Well Pads													
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	2.0 acres	632	1,264	632	86	172	86	32	64	32	750	1,500	750
New Green River Oil Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	0.2 acre	2,135	427	427	300	60	60	65	13	13	2,500	500	500
New Deep Gas Well Pads on 40-Acre Surface and Downhole Spacing	3.0 acres	2,135	6,405	2,135	300	900	300	65	195	65	2,500	7,500	2,500
Subtotal	**--**	**4,902**	**8,096**	**3,194**	**686**	**1,132**	**446**	**162**	**272**	**110**	**5,750**	**9,500**	**3,750**
Access Roads													
New Roads Co-located with Pipelines	40 feet[2]	208 miles	1,008	1,008	31 miles	150	150	4 miles	19	19	243 miles	1,178	1,178
Existing Roads Co-located with New Pipelines	10 feet[3]	311 miles	377	377	34 miles	41	41	18 miles	22	22	363 miles	440	440
Subtotal	**--**	**519 miles**	**1,385**	**1,385**	**65 miles**	**192**	**192**	**22 miles**	**41**	**41**	**606 miles**	**1,618**	**1,618**
Pipelines													
Pipelines Co-located with New Roads	60 feet[4]	208 miles	1,513	630	31 miles	225	94	4 miles	29	12	243 miles	1,767	736[5]
Pipelines Co-located with Existing Roads	60 feet[4]	311 miles	2,262	942	34 miles	247	103	18 miles	131	55	363 miles	2,640	1,100[5]
Transmission Lines	30 feet	27 miles	98	49	2 miles	7	4	5 miles	18	9	34 miles	124	62
Distribution Lines	20 feet	--	--	--	--	--	--	--	--	--	156 miles	N/A[6]	N/A
Subtotal	**--**	**546 miles**	**3,874**	**1,622**	**67 miles**	**480**	**201**	**27 miles**	**178**	**76**	**796 miles**	**4,531**	**1,898**
Central Facilities													
Compressor Stations (New and Upgrades)	9.4 acres	21	197	197	3	28	28	0	0	0	24	226	226
Gas Processing Plants	10.0 acres	0	0	0	1	10	10	0	0	0	1	10	10
Water Treatment and Injection Facilities	8/5 acres[7]	12	78	78	1	8	8	0	0	0	13[8]	86	86
Gas and Oil Separation Plants (GOSPs)	22.0 acres	10	220	220	2	44	44	0	0	0	12	264	264
Fresh Water Collector Well	1.7 acre	1	0	0	0	0	0	0	0	0	1	1.7	.7
Pump Stations	3.0 acres	5	15	15	0	0	0	1	3	3	6	18	18
Generating Stations (Substations)	5.0 acres	10	50	50	1	5	5	0	0	0	11	55	55
Subtotal	**--**	**59**	**560**	**560**	**9**	**95**	**95**	**1**	**3**	**3**	**68**	**659**	**659**
Total New Disturbance	**--**	**--**	**13,915**	**6,761**	**--**	**1,899**	**934**	**--**	**494**	**230**	**--**	**16,308[9]**	**7,925**

Source Note: Project totals for numbers of wells, miles of roads/pipelines, and numbers of facilities have been broken down by federal, state and private surface land categories for analysis purposes only. These totals represent a rough estimate based on conceptual locations of surface facilities and infrastructure.

1 Residual disturbance calculations are based on the assumption that interim reclamation will be initiated and successful.
2 Initial disturbance assumes that a 100-foot wide disturbance corridor would be needed for construction, of which 40 feet would be used for new road construction and 60 feet for pipeline/utility line installation.
3 Initial disturbance assumes that a 70-foot wide disturbance corridor would be needed for construction, of which 10 feet would be used for general road improvements and 60 feet for pipeline/utility line installation.
4 Initial disturbance assumes that a 60-foot wide disturbance corridor would be needed for pipeline/utility line installation within new and existing road ROWs.
5 Residual disturbance assumes that 35-foot wide portion of the original 60-foot wide disturbance corridor would be reclaimed leaving a 25-foot wide corridor for the long-term pipeline/utility corridor.
6 Proposed distribution lines would be co-located within road and pipeline ROWs, so no additional disturbance would be associated with these facilities.
7 Includes six new and six expanded water treatment and injection facilities.
8 Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each.
9 Numbers are rounded to the nearest whole number.

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Each generating station would connect with overhead transmission lines to the other stations so as to provide a redundant power supply. While it is anticipated that excess electricity would be generated, it is unlikely that this electricity would be sold back to the grid due to the limitations in obtaining new power purchase agreements with existing utilities.

Transmission lines would run cross-country and would be installed in a 30-foot-wide construction ROW with a long-term, 15-foot maintenance/inspection ROW. Approximately 34 miles of transmission lines would be installed along a 30-foot-wide disturbance corridor. Therefore, the initial surface disturbance resulting from installation of the proposed transmission lines would be approximately 124 acres. Following construction activities, portions of the initial 30-foot-wide disturbance corridor for power lines not needed for inspection and maintenance would be reclaimed. This would reduce the long-term disturbance associated with power line installation to approximately 62 acres.

A series of overhead or buried distribution lines would carry electricity from transmission lines to central facilities located on individual well pads. In addition, approximately 156 miles of overhead or buried distribution lines would be installed in the same ROW corridors as the proposed water pipelines (see **Sections 2.3.1.2** and **2.3.1.3**). Therefore, there would be no appreciable increase in initial surface disturbance beyond the calculations previously estimated for pipelines that are co-located with new and existing roads.

Surface facilities along power lines would consist of the following features:

- Transmission lines would be built on single tubular steel poles with a span of approximately 600 feet between the poles.

- Above ground distribution lines would be built on a mix of tubular steel and single wood utility poles approximately 65 feet tall. The span between poles would be approximately 300 feet for wooden poles and 600 feet for tubular steel poles.

- Buried distribution lines would be aluminum 3-1/C cable installed with ground and junction boxes, as needed.

Electrification of the MBPA would take approximately 7 years to complete. Consequently, under this alternative, gas-fired engines would be used for operational field equipment until the electrification process is complete. Equipment needed for electrification is listed in **Table 2.5.1.2-1.**

2.5.2 Interim Reclamation

Under Alternative C, approximately 8,383 acres of initial disturbance (51 percent) associated with construction of proposed well pads, road and pipeline ROWs, and other project facilities not needed for operational purposes would be reclaimed. This would reduce the long-term disturbance associated with implementation of Alternative C to approximately 7,925 acres.

Table 2.5.1.2-1. Surface Equipment Required for Field-Wide Electrification

Surface Facility	Surface Equipment Per Facility/Pad
Primary Substation/Generation Zone	• Four, 25-MWe gas turbine generators; • Two, 10-MWe steam turbines; • One water softening plant
Well Pads	• One 100 kVA, 24.5 kV-480V pole mount or pad mount transformer; • One 480V, 225Amp Bus rating, NEMA 4X Outdoor Rated Low Voltage Motor Control center; • One 480V, 40-hp rated, Well Pump Motor Soft Starter; and • One 480V, 100 Amp Bus Rated, Heat Trace Panel
Compressor Stations	• One 30-foot X 14-foot Power Distribution Center Building; • One 5000 kVA, 24.5-4.16 kV pad mount transformer; • One 500 kVA, 4160-480V pad mount transformer; • One 4160V, 1200 Amp Bus Rating, Low Voltage Motor Control Center; and • Small electrical transformer and distribution power for building and site lighting and other miscellaneous loads
Gas Processing Plant	• One 30-foot X 14-foot Power Distribution Center Building; • One 1000 kVA, 24.5-4.16 kV pad mount transformer; • One 150 kVA, 4160-480V pad mount transformer; • One 4160V, 1200 Amp Bus Rating, Medium Voltage Controller; • 600 Amp Bus Rating, Low Voltage Motor Control Center; and • Small electrical transformer and distribution power for building and site lighting and other miscellaneous loads.
Water Treatment and Injection Facility	• One 24-foot X 12-foot Power Distribution Center Building; and • One 2000 kVA, 24.5-4.16 kV pad mount transformer.
GOSPs	• One 24-foot X 12-foot Power Distribution Center Building; • One 1500 kVA, 24.5-480V pad mount transformer; • One 480V, 2000 Amp Bus Rating, Low Voltage Motor Control center; and • Small electrical transformer and distribution power for building and site lighting and other miscellaneous loads.

2.5.3 Workforce Requirements

The active workforce needed for development of Alternative C is estimated in **Table 2.5.3-1**.

Table 2.5.3-1. Estimated Workforce Requirements under Alternative C

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Construction and Installation						
Access Road	4 days/mile	606 miles	8	19,392	1,212	5
Well Pad	3 days/site	5,750	8	138,000	8,625	36
Pipelines, Transmission and Distribution Lines	10 days/mile	796 miles	10	79,600	4,975	21

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Drilling and Casing	4 days/well	5,750	8	184,000	11,500	48
Well Completion	4 days/well	5,750	20	460,000	28,750	120
Well Production	10 days/well	5,750	16	920,000	57,500	240
Central Facilities	45 days/site	68	20	61,200	3,825	16
Total				**1,862,192[1]**	**116,387**	**486**
Operation and Maintenance						
Road/Well Pad Maintenance	120 days/year	N/A	3	12,600	360	2
Pumpers	260 days/year	N/A	36	327,600	9,360	39
Office	260 days/year	N/A	4	36,400	1,040	4
Well Workover	5 days/well	30 per year	2	10,500	300	1
Total				**387,100[2]**	**11,060**	**46**
Reclamation and Abandonment[3]						
Wells	3 days/well pad	5,750	4	69,000	N/A	--
Roads, Utility Lines and Pipelines	4 day/mile	606 miles	4	9,696	N/A	--
Central Facilities	30 day/facility	68	16	32,640	N/A	--
Total				**111,336**	--	--

[1] Based on a 16-year construction schedule.
[2] Based on a 35-year construction, production, and operation schedule.
[3] Includes interim reclamation.

2.6 ALTERNATIVE D – RESOURCE PROTECTION (AGENCY PREFERRED ALTERNATIVE)

In accordance with CEQ regulations, the BLM is required to identify a preferred alternative in the EIS if one or more exists. Alternative D, the Resource Protection Alternative, is the Agency Preferred Alternative. Alternative D was developed to respond to issues raised during scoping about reducing potential impacts to sensitive resource and land uses. For the MBPA, the primary objective of the Resource Protection Alternative is to meet the purpose and need for the Project while minimizing impacts to floodplain, riparian, and wetland habitats and threatened and endangered species by 1) avoiding new surface disturbance within the Pariette Wetlands Area of Critical Environmental Concern (ACEC); 2) minimizing the amount of new surface within USFWS proposed Level 1 and 2 Core Conservation Areas (for two federally-listed plant species: the Uinta Basin hookless cactus [*Sclerocactus wetlandicus*] and the Pariette cactus [*Sclerocactus brevispinus*]); 3) precluding surface disturbance (with the exception of

Newfield's proposed water collector well) within 100-year floodplain and riparian habitats; and 4) adjusting new development based on existing well density in other portions of the MBPA through the use of directional drilling technology. **Figure 2-4 (Attachment 1)** depicts the location of the ACEC and Core Conservation Areas in the MBPA.

2.6.1 Pariette Wetlands ACEC

Under Alternative D, the most restrictive conditions for oil and gas development would occur within the Pariette Wetlands ACEC as follows: 1) No new surface disturbance or well pad expansions would be allowed on federal lands; and 2) SITLA and private lands would follow UDOGM and SMA requirements. In order to access the natural gas reserves beneath the Pariette ACEC, directional wells would be drilled from both new multi-well pads and existing well pads located adjacent to, but outside of, the ACEC. Recent advancements in horizontal drilling technology have increased the maximum horizontal displacement to distances of up to 2,500 feet without significant technical and economic challenges. While a substantial portion of the hydrocarbon reserves could be recovered under the Pariette Wetlands ACEC as a result of directional drilling, it is estimated that approximately 6,605 acres of natural gas reserves beneath the Pariette ACEC (or approximately 62 percent of the total area of the Pariette ACEC) would be inaccessible because of limitations on drilling locations.

2.6.2 Cactus Core Conservation Areas

Another principal component of Alternative D entails environmental protection measures proposed for *Sclerocactus* species. Under Alternative D, BLM would adopt enhanced USFWS management guidelines and recommended protection of Core Conservation Areas to minimize the effects of energy development on *Sclerocactus* habitat. As proposed under Alternative D, two levels of core conservation areas would be used to manage development in relation to cactus habitat. Areas where cactus numbers are known to be highly concentrated (most dense per unit area) are classified as Level 1 Core Conservation Areas. The most restrictive conditions for oil and gas development would occur in Level 1 areas, where no new surface disturbance or well pad expansions would be allowed. The majority of these areas are located within the Pariette ACEC. The total size of the Level 1 Core Conservation Areas located within the Pariette Wetlands ACEC is 4,337 acres

In Level 2 areas located outside the Pariette ACEC, surface disturbance would be minimized to the greatest extent practicable by using existing infrastructure (i.e., access roads and pipelines) and directional drilling from multi-well pads that would either require the expansion of existing well pads or the construction of a limited number of new multi-well pads. Under Alternative D, approximately 155 fewer well locations would be drilled and 766 fewer acres of surface disturbance would occur within Level 1 and 2 Core Conservation Areas than would occur under the Proposed Action. Additionally, with an increased number of Green River oil wells that would be converted to injection wells (discussed below), Alternative D would further reduce surface disturbance in Level 2 Core Conservation Areas by reducing existing infrastructure to smaller disturbance areas. This would help reduce the disturbance in Level 2 Core Conservation Areas that already exceed the 5 percent surface disturbance density ceiling.

2.6.3 New Development Based on Existing Well Density

An additional goal of Alternative D is to reduce the amount of surface disturbance from the proposed project by reducing the number of new wells pads, reclaiming areas of existing disturbance, and increasing the use of multi-well pads. Numerous existing single-well pads would be converted to a complex of multi-well, directional drilling pads and waterflood injection wells, which would have a lower overall disturbance in comparison to the Proposed Action and Alternative C.

As discussed in Section 2.2**, Figure 2.6-1 (Attachment 1)** shows the existing high and low-density development areas within the MBPA. High-density development areas are those areas that have from 6- to 16-well pads per 640-acre section (i.e., one [1] well pad per 40 to 106 acres). Low-density development areas are defined as those areas that have had no gas development at all or contain up to five well pads per section.

Of the 197 sections (or portions of sections) within the MBPA, 115 sections (or portions of sections [about 58 percent]) are within the high-density development areas. Average existing surface disturbance within the high-density development areas is 39.0 acres per section and the average number of well pads per section is 14.3. Approximately 82 sections (or portions of sections) occur within the low-density development areas. The average existing disturbance within the low-density development areas is 11.9 acres per section and the average number of existing well pads per section is 2.8.

Within high-density development areas that contain 16 well pads per section, four of the 16 existing wells pads within each section would be expanded by about 0.2 acres for directional drilling (up to four wells from each pad) and the remaining 12 well pads within each section would be converted to waterflood injection wells. In sections that contain fewer than 16 well pads, three or fewer of the existing wells pads within each section would be expanded by about 0.2 acres for directional drilling and the remaining well pads within each section would be converted to waterflood injection wells resulting in the reclamation of 1.74 acres per pad. This would result in a substantial decrease in the residual or long-term amount of surface disturbance within the MBPA compared to the other action alternatives (see **Table 2-7**).

This effect is even more dramatic when shown graphically. **Figure 2.6-2 (Attachment 1)** compares a typical 640-acre section drilled at a 40-acre surface density (16 well pads), with simulations of four of the well pads expanded for directional drilling and the conversion of the remaining 12 well pads into waterflood injection wells. Under this scenario, the 12 existing pads, with an average size of 2 acres each (or 24 acres total) would be reclaimed down to approximately 0.26 acre, which is the average area of disturbance associated with a waterflood injection well. Therefore, an average of 1.74 acres would be reclaimed for each well pad that is converted into a waterflood injection well. This equates to nearly 21 acres per section (for 12 wells), or a total of 1,991 acres within the high-density development areas.

For low-density development areas with no existing oil and gas development, the proposed surface density would be no more than four new well pads per 640-acre section (i.e., one well pad per 160 acres). In sections with previous existing oil and gas development, one new multi-well pad would be permitted and one or more existing well pads would be used as multi-well pad(s). However, there would be no restriction on the number of wells that could be drilled from those well pads provided that the wells conform to UDOGM downhole spacing requirements, which is currently 20 acres.

This alternative would incorporate the same construction and operational components as the Proposed Action and Alternative C, but with fewer new well pad locations and a substantially greater number of multiple directional wells drilled. The volume of water needed and number of water injection wells would be higher under Alternative D because the number of oil wells requiring secondary recovery would be higher. Under Alternative D, approximately 5,058 oil and gas wells would be developed on BLM, State, and private lands in the MBPA. Newfield would drill associated wells at an average rate of 360 wells per year. Under this drilling scenario, construction, drilling, and completion of all 5,058 wells would occur for approximately 14 years. The total number of wells drilled and would depend largely on outside factors such as production success, engineering technology, reservoir characteristics, economic factors, commodity prices, rig availability, and lease stipulations. The anticipated life of an individual well is 20 to 30 years, and the anticipated time it would take for field abandonment and final reclamation is 5 years.

Therefore, the anticipated LOP under Alternative D would be 39 to 49 years. Conceptual locations for the approximately 5,058 wells and other surface facilities are illustrated on **Figure 2-4 (Attachment 1)**.

Alternative D includes the following primary components (see **Figure 2-4 – Attachment 1**):

- Development of up to 204 Green River oil wells with a 160-acre surface density drilled from new 2-acre well pads, all of which would eventually be converted into waterflood injection wells;
- Development of up to 1,539 vertical deep gas wells on 40-acre spacing drilled from new 3-acre well pads;
- Development of up to 3,315 Green River oil wells on 20-acre spacing that would be vertically, directionally, or horizontally drilled from existing and/or proposed 40-acre spaced Green River oil well pads, of which, 940 would eventually be converted to waterflood injection wells. This would occur over an approximate 10-year period.
- Construction of approximately 73 miles of new 100-foot wide ROW that would be used for new road construction (40-foot width) and pipeline installation (60-foot width). Up to 70-foot wide expansion along approximately 331 miles of existing access road ROW that would be used for road upgrade (10-foot width) and pipeline installation (60-foot width);
- Construction of up to 17 new compressor stations for deep gas well development;
- Construction of up to one 50-MMscf/d centralized Green River oil well gas processing plant;
- Construction of up to nine gas driven water treatment and injection facilities for management and distribution and injection of produced water;
- Construction of up to eight GOSPs for oil and produced water collection;
- Development of one fresh water collector well for waterflood operations; and
- Construction of four water pump stations.

Surface disturbance anticipated under Alternative D is shown in **Table 2.6-1**. Initial surface disturbance would occur during and immediately after the construction, drilling, completion, and testing activities. Prior to interim reclamation, initial surface disturbance for well pads, access roads, pipeline ROWs, and other surface facilities would equal approximately 9,805 acres. Those portions of the well pads, access road ROWs, pipeline ROWs, and other facilities not needed for production operations would be reclaimed within two to three growing seasons assuming optimal conditions are present. The remaining surface disturbance would be residual or “long-term” disturbance of approximately 2,818 acres during the LOP.

Specific details of construction-related activities and specific design features for well completion; production, operations, and maintenance activities; final reclamation and abandonment; and hazardous materials and solid waste under the Alternative D are identical to those previously described in **Section 2.2**, *Development Activities Common to All Action Alternatives* and will not be repeated further in this section. Specific details of project activities, specific design features, and surface disturbance summaries that are unique to Alternative D are described below in the following sections.

Table 2.6-1. Surface Disturbance under Alternative D

Project Feature	Size (disturbance width [feet] or acres/facility)	Federal Lands			State Lands			Private Lands			Project Total		
		Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]	Number or Miles	Initial (short-term) Surface Disturbance (acres)	Residual (long-term) Surface Disturbance (acres)[1]
Well Pads													
New Green River Oil or Deep Gas Wells Pads with a 160-Acre Surface Density	2.0 acres	172	344	172	30	60	30	2	4	2	204	408	204
New Green River Oil Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	0.2 acre	2,873	575	575	348	70	70	94	19	19	3,315	663	663
Expansion of Existing Well Pads to Accommodate Deep Gas on 40-Acre Surface and Downhole Spacing	3.0 acres	1,326	3,978	1,326	171	513	171	42	126	42	1,539	4,617	1,539
Subtotal	**--**	**4,371**	**4,897**	**2,073**	**549**	**643**	**271**	**138**	**149**	**63**	**5,058**	**5,688**	**2,406**
Well Pad Conversions													
Existing Well Pads Converted to Water Injection Wells	-1.74 acres	975	--	-1,697	109	--	-190	30	--	-52	1,144	--	-1,991
Subtotal New Well Pads	**--**	**4,371**	**4,897**	**2,073**	**549**	**643**	**271**	**138**	**149**	**63**	**5,058**	**5,688**	**2,406**
Net Total	**--**	**--**	**4,897**	**376**	**--**	**643**	**81**	**--**	**149**	**11**	**--**	**5,688**	**415**
Access Roads													
New Roads Co-located with Pipelines	40 feet[2]	73 miles	354	354	0 miles	0	0	0 miles	0	0	73 miles	354	354
Existing Roads co-located with New Pipelines	10 feet[3]	292 miles	354	354	25 miles	30	30	14 miles	17	17	331 miles	401	401
Subtotal	**--**	**365 miles**	**708**	**708**	**25 miles**	**30**	**30**	**14 miles**	**17**	**17**	**404 miles**	**755**	**755**
Pipelines													
Pipelines Co-located with New Roads	60 feet[4]	73 miles	531	221	0 miles	0	0	0 miles	0	0	73 miles	531	221[5]
Pipelines Co-located with Existing Roads	60 feet[4]	292 miles	2,124	885	25 miles	182	76	14 miles	102	42	331 miles	2,407	1,003[5]
Subtotal	**--**	**365 miles**	**2,655**	**1,106**	**25 miles**	**182**	**76**	**14 miles**	**102**	**42**	**404 miles**	**2,938**	**1,224**
Central Facilities													
Compressor Stations (New and Upgrades)	9.4 acres (avg.)	15	141	141	2	19	19	0	0	0	17	160	160
Gas Processing Plants	10.0 acres	0	0	0	1	10	10	0	0	0	1	10	10
Water Treatment and Injection Facilities	8/5 acres[6]	9	57	57	1	8	8	0	0	0	10	65[7]	65
Gas and Oil Separation Plants (GOSPs)	22.0 acres	7	154	154	1	22	22	0	0	0	8	176	176
Fresh Water Collector Well	1.7 acre	1	0	0	0	0	0	0	0	0	1	1.7	.7
Pump Stations	3.0 acres	4	12	12	0	0	0	0	0	0	4	12	12
Subtotal	**--**	**36**	**364**	**373**	**5**	**60**	**60**	**0**	**0**	**0**	**41**	**423**	**423**
Total New Disturbance	**--**	**--**	**8,623**	**2,502**	**--**	**914**	**246**	**--**	**268**	**70**	**-**	**9,805**	**2,818**

Source Note: Project totals for numbers of wells, miles of roads/pipelines, and numbers of facilities have been broken down by federal, state and private surface land categories for analysis purposes only. These totals represent a rough estimate based on conceptual locations of surface facilities and infrastructure.

1 Residual disturbance calculations are based on the assumption that interim reclamation will be initiated and successful.

2 Initial disturbance assumes that a 100-foot wide disturbance corridor would be needed for construction, of which 40 feet would be used for new road construction and 60 feet for pipeline/utility line installation.

3 Initial disturbance assumes that a 70-foot wide disturbance corridor would be needed for construction, of which 10 feet would be used for general road improvements and 60 feet for pipeline/utility line installation.

4 Initial disturbance assumes that a 60-foot wide disturbance corridor would be needed for pipeline/utility line installation within new and existing road ROWs.

5 Residual disturbance assumes that 35-foot wide portion of the original 60-foot wide disturbance corridor would be reclaimed leaving a 25-foot wide corridor for the long-term pipeline/utility corridor.

6 Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each.

7 Includes nine water treatment and injection facilities.

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2.6.4 Alternative-specific Activities

2.6.4.1 Well Pad Construction

Under Alternative D, 5,058 wells would be developed, consisting of up to 204 Green River oil wells on a 160-acre surface density, all of which would eventually be converted into waterflood injection wells after about 3 years of production; 3,315 Green River oil wells on 20-acre downhole spacing that would be vertically, directionally, or horizontally drilled from existing and/or proposed 40-acre spaced Green River oil well pads, 936 of which would eventually be converted to waterflood injection wells; and 1,539 new well pads to accommodate deep gas on 40-acre surface and downhole spacing. Therefore, the initial surface disturbance resulting from the construction of all 5,058 wells would be approximately 5,688 acres (see **Table 2.6-1**). This would include approximately 408 acres for the 204 Green River oil wells, 663 acres for the 3,315 Green River oil wells on existing or proposed well pads, and 4,617 acres for the 1,539 vertical deep gas wells. Following well completion(s), portions of the well pad not needed for production would be reseeded and reclaimed according to specifications of the appropriate SMA. Assuming successful interim reclamation, long-term well pad disturbance under Alternative D would be reduced to approximately 2,406 acres.

Under Alternative D, up to 940 Green River oil wells would be converted to waterflood injection wells. This would occur over an approximate 10-year period. Under this scenario, the 1,144 existing Green River oil pads (with an average size of 2 acres each) would be reclaimed down to approximately 0.26 acre, which is the average area of disturbance associated with a waterflood injection well. Therefore, an average of 1.74 acres would be reclaimed for each Green River oil well pad that is converted into a waterflood injection well. This equates to a total of 1,694 acres reclaimed within the MBPA over the long-term. Assuming successful interim reclamation, this would reduce the long-term well pad disturbance under Alternative D to approximately 415 acres (see **Table 2.6-1**).

2.6.4.2 Access Road Construction

Implementation of Alternative D would require the construction of up to 73 miles of access roads and expansion and/or upgrades to approximately 331 miles of existing roads on BLM, State, and private lands. ROWs and surface corridor widths for roads under Alternative D would be consistent with activities previously described for the Proposed Action (see **Section 2.3.1.2**). The initial surface disturbance resulting from the construction of new access roads and expansion and/or upgrades to existing roads would be approximately 354 and 401 acres, respectively.

2.6.4.3 Pipeline Construction

Under Alternative D, approximately 73 miles of pipeline would be installed adjacent to proposed access roads (co-located) and approximately 331 miles of pipeline would be installed along existing roads. Corridor widths for pipelines under Alternative D would be the same as those previously described for the Proposed Action (see **Section 2.3.1.3**), except that under Alternative D, all pipelines would be buried. Installation of pipelines along proposed and existing roads would result in approximately 531 and 2,407 acres of initial surface disturbance, respectively. Following successful interim reclamation, the long-term disturbance associated with these facilities would be 221 and 1,003 acres for pipelines co-located along new and existing roads, respectively. As indicated in **Section 2.2.2.2**, in limited situations, a proposed pipeline would be installed independent of an access road (i.e., cross-country). Under Alternative D, an estimated 40 miles of cross-country pipeline could be installed. Based on a 50-foot wide corridor, cross-country pipelines could result in approximately 242 acres of surface disturbance. As there are no conceptual locations for cross-country pipelines they are not shown on maps for Alternative D, nor are they included in the GIS-based disturbance calculation tables.

2.6.4.4 Compressor Stations

Under Alternative D, Newfield would construct up to 17 new compressor stations within the MBPA. Each station would occupy an approximate 10 acre site and would produce up to 8,000-hp of compression. Compressor stations would not be reclaimed until they are no longer needed (up to 50 years) resulting in prolonged surface disturbance of approximately 160 acres.

2.6.4.5 Central Processing Plant

Under Alternative D, Newfield would construct one new central gas processing plant within the MBPA. The plant would occupy a site approximately 10 acres in size. Therefore, the initial surface disturbance resulting from the construction of the one new central gas processing plant would be approximately 10 acres.

Central facilities, including the proposed central gas processing plant would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 10 acres.

2.6.4.6 Water Treatment and Injection Facilities

Under Alternative D, up to nine water treatment and injection facilities would be constructed within the MBPA. The proposed water treatment facilities would be used for recycling of produced water that would either be co-mingled with fresh water and piped for waterflood injection wells, or trucked from the facility to be used at subsequent wells for completion activities.

Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each. Therefore, the initial surface disturbance resulting from the construction of five new water treatment and injection facilities and expansion of five existing facilities would be approximately 65 acres.

As with other production facilities, water treatment and injection facilities would not be reclaimed during interim reclamation because the total area of initial surface disturbance would be needed for operational activities. Therefore, the residual long-term surface disturbance would be the same as the initial surface disturbance of approximately 65 acres.

Additional information on proposed water treatment and injection facilities is provided in **Section 2.2.2.7**.

2.6.4.7 Gas and Oil Separation Plants (GOSPs)

Under Alternative D, up to eight new GOSPs would be constructed that would be used for the initial separation of produced water and gas from the oil prior to shipment to the refinery for further processing. Conceptual locations for GOSPs are illustrated on **Figure 2-4 (Attachment 1)**. Each new GOSP would occupy a 22-acre site and would remain in use for the anticipated LOP (up to 50 years) making a prolonged disturbance of approximately 176 acres.

Additional information on proposed GOSPs is provided in **Section 2.2.2.8**.

2.6.4.8 Pump Stations

Under Alternative D, four water pump stations would be constructed to ensure delivery of water to treatment and injection facilities. Each new pump station would occupy a 3-acre site resulting in a total long-term disturbance of 12 acres.

2.6.5 Well Drilling

Under Alternative D, 5,058 wells would be developed, consisting of up to 204 Green River oil wells on a 160-acre surface density, all of which would eventually be converted into waterflood injection wells after about 3 years of production; 3,315 Green River oil wells on 20-acre downhole spacing that would be vertically, directionally, or horizontally drilled from existing and/or proposed 40-acre spaced Green River oil well pads, 952 of which would eventually be converted to waterflood injection wells after about 3 years of production; and 1,539 existing well pads that would be expanded to accommodate deep gas on the Green River, Wasatch, Mesaverde, Blackhawk/Mancos, and/or Frontier/Dakota formations 40-acre spacing pattern. Of the 5,058 wells drilled under the Proposed Action, approximately 4,371 would be drilled on Federal Lands; 549 would be drilled on State lands; and 138 wells would be drilled on Private land (see **Table 2.6-1**). Numbers of wells have been broken down by federal, state and private surface land categories for analysis purposes only, and could change based on site-specific conditions.

Based upon current technology and drilling rates in the MBPA, up to 12 drilling rigs could be active in the MBPA at any given time. Depending on the type of well drilled (i.e., Green River oil well or deep gas well), an average of 323 wells would be drilled annually. Also, based on the amount of time needed to drill a deep gas well, the timeframe to fully explore and develop the resource may need to be extended up to 30 years based on commodity pricing for natural gas.

Information on well drilling is provided in **Section 2.2.3**.

2.6.6 Interim Reclamation

Under Alternative D, approximately 6,987 acres of initial disturbance (71 percent) associated with construction of proposed well pads, road and pipeline ROWs, and other project facilities not needed for operational purposes would be reclaimed. This would reduce the long-term disturbance associated with implementation of Alternative D to approximately 2,818 acres.

Information on interim reclamation is provided in **Section 2.2.5**.

2.6.7 Water Requirements

2.6.7.1 Drilling and Completion

An average of 7,000-bbls (0.9 acre-feet) of water would be required to drill and complete an oil well and up to 48,000-bbls (6.2 acre-feet) of water would be used to drill and complete a deep gas well under Alternative D. Total water use for drilling and completion of all 5,058 wells under Alternative D would be approximately 12,710 acre-feet (see **Table 2.6.7-1**).

Information on water requirements for drilling and completion activities is provided in **Section 2.2.8.1**.

Table 2.6.7-1. Water Requirements for Well Drilling and Completion, Dust Suppression, and Waterflooding Operations under Alternative D

Activity/Phase	Number of Wells	Amount of Water Required per Well (acre-feet)	Total Water Use (acre-feet)	Annual Water Use (acre-feet)
Well Drilling and Completion[1]				
New Green River Oil Wells on 40-Acre Surface and Downhole Spacing	204	0.9	184	13*
New Green River Oil Wells on 20-acre Downhole Spacing on Existing and/or Proposed 40-acre Surface Spaced Green River Oil Well Pads	3,315	0.9	2,984	213*
New Deep Gas Well Pads on 40-Acre Surface and Downhole Spacing	1,539	6.2	9,542	682*
Subtotal for the 14-year active well drilling and completion period	**5,058**	**--**	**12,710**	**908***
Dust Suppression				
Construction of New Well Pads and Associated Roads and Pipeline/Utility Corridors	505	0.08[2]	40	3
Subtotal for the 14-year active well drilling and completion period	**505**	**--**	**40**	**3***
Operation of New Well Pads and Associated Roads and Pipeline/Utility Corridors	505	0.13[3]	1,320 – 1,980[4]	66
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**1,320 – 1,980**	**66**
Waterflooding Infrastructure and Operations				
Conversion of up to 1,144 Proposed Wells to Injection Wells	1,144	0.01[5]	83,520 – 125,280[6]	4,176
Subtotal for the 20- to 30-Year Construction and Operational Period	**--**	**--**	**83,520 – 125,280**	**4,176**
TOTAL	**--**	**--**	**97,590– 140,010**	**5,153**

1 Assumes a 14-year active well drilling and completion period.

2 Approximately five water trucks (approximately 650-bbls or 0.08 acre-feet) would be needed for dust suppression per new well pad, access road, and pipeline/utility corridor during construction activities, for approximately 10 percent of the proposed project (i.e., up to 505 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

3 Approximately eight water truck (approximately 1000-bbls or 0.13 acre-feet) would be needed annually for dust suppression per new well pad, access road, and pipeline/utility corridor during project operation, for approximately 10 percent of the proposed project (i.e., up to 505 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities).

[4] Calculated based on 66 acre-feet annually over the 20 to 30-year construction and operational period.

[5] Assumes 0.01 acre-feet of water per well daily.

[6] Calculated based on 4,176 acre-feet annually over the 10-year conversion period.

[*] Based on average annual water use.

Note: Summations may not total precisely due to rounding.

2.6.7.2 Dust Suppression

Approximately 650-bbls or 0.08 acre-feet of fresh water would be needed for dust suppression per new well pad, associated access road, and pipeline/utility corridor for approximately 10 percent of the proposed during construction (i.e., for approximately 505 new well pads and their associated roads, pipeline/utility corridors, and other surface facilities). A total of approximately 3 acre-feet of fresh water would be needed for dust suppression during construction activities under Alternative D.

In addition, approximately 1,000 bbls or 0.13 acre-feet of water would be needed annually for dust suppression per well pad, associated access road, and pipeline/utility corridor during project operations, again for approximately 10 percent of the proposed project (i.e., for approximately 505 well pads and their associated roads, pipeline/utility corridors, and other surface facilities). Therefore, implementation of Alternative D would require approximately 66 acre-feet of water annually for dust abatement during project operations.

Information on water used for dust suppression activities is provided in **Section 2.2.8.2**.

2.6.7.3 Waterflooding Infrastructure and Operations

A total of approximately 75 to 100-bpd (or approximately 0.01 acre-feet per day) of water would be required for each waterflood injection well. Under Alternative D, Newfield would convert 1,144 of their proposed oil wells to injection wells that require approximately 11.44 acre-feet of fresh water per day for injection purposes (0.01 acre feet/well multiplied by up to 1,144 wells). Based on the requirement of 11.44 acre-feet of water per day, the annual water requirement for waterflooding operations would be approximately 4,176 acre-feet per year, or about 41,760 acre-feet over the 10-year conversion period. Under Alternative D, Newfield would be required to use 40 to 50% recycled water for waterflooding purposes.

Information on water requirements for waterflooding infrastructure and operations is provided in **Section 2.2.8.3**.

2.6.8 Produced Water Disposal

Under Alternative D, up to nine new water treatment and injection facilities and a new water disposal well would be constructed. Surface disturbance from the 10 water management facilities would be approximately 65 acres. Surface disturbance from construction and drilling of the water disposal well is included in the surface disturbance summarized for well pads. In addition, up to four pump stations would be constructed under Alternative D, disturbing a total of approximately 12 acres.

If required, the water disposal well would be drilled in the MBPA on an existing well pad or using an existing well boring. The new disposal well would have an average capacity of 4,000 BWPD. Although future water production is difficult to predict because of variable water saturation conditions as the oil and gas formations are produced and depleted, it is estimated for purposes of analysis in this EIS that

Newfield will recycle nearly all of the water that would be produced under this alternative for use in waterflood operations.

Additional information on produced water disposal is provided in **Section 2.2.9**.

2.6.9 Workforce Requirements

The active workforce needed to develop Alternative D is estimated in **Table 2.6.6-1**.

Table 2.6.6-1. Estimated Workforce Requirements under Alternative D

Work Category	Time Requirements	Number of Facilities	Personnel Required (No. per day)	Workdays for Project	Average Workdays per Year	Average Workers per Day
Construction and Installation						
Access Road	4 days/mile	404 miles	8	12,928	923	4
Well Pad	3 days/site	5,058	8	121,392	8,671	36
Pipelines	10 days/mile	404 miles	10	40,400	2,886	12
Drilling and Casing	4 days/well	5,058	8	161,856	11,561	48
Well Completion	4 days/well	5,058	20	404,640	28,903	120
Well Production	10 days/well	5,058	16	809,280	57,806	241
Central Facilities	45 days/site	41	20	36,900	2,636	11
Total				**1,587,396**	**113,386**[1]	**472**
Operation and Maintenance						
Road/Well Pad Maintenance	120 days/year	N/A	3	16,560	360	1
Pumpers	260 days/year	N/A	36	430,560	9,360	39
Office	260 days/year	N/A	3	35,880	780	3
Well Workover	5 days/well	15 per year	2	6,900	150	1
Total				**489,900**	**10,650**[2]	**44**
Reclamation and Abandonment[3]						
Wells	3 days/well pad	5,058	4	60,696	N/A	--
Roads and Pipelines	4 day/mile	404 miles	4	6,464	N/A	--
Central Facilities	30 day/facility	41	16	19,680	N/A	--
Total				**86,840**	**--**	**--**

1 Based on a 14-year construction schedule.
2 Based on a 46-year construction, production, and operation schedule.
3 Includes interim reclamation.

2.7 COMPARISON SUMMARY OF DESIGN FEATURES AMONG ALTERNATIVES

Table 2-7 summarizes the number of well pads, miles of access road, miles of pipeline, production facilities, and other design or project features that would occur under each alternative.

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Table 2.7-1. Design Feature Summary Comparison among Alternatives

ALTERNATIVE		ALTERNATIVE A - PROPOSED ACTION			ALTERNATIVE B - NO ACTION ALTERNATIVE			ALTERNATIVE C - FIELD-WIDE ELECTRIFICATION			ALTERNATIVE D - AGENCY PREFERRED ALTERNATIVE		
Project Feature	**Size (disturbance width [feet] or acres/facility)**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**
Well Pads													
New Green River Oil Well Pads on 40-acre Surface and Downhole Spacing	2.0 acres	750	1,500	750	128	256	128	750	1,500	750	--	--	--
New Green River Oil Well Pads on 20-acre Spacing on Existing and/or Proposed 40-acre Spaced Green River Oil Well Pads	0.2 acre	2,500	500	500	419	84	84	2,500	500	500	3,315	663	663
New Deep Gas Well Pads on 40-acre Surface and Downhole Spacing	3.0 acres	2,500	7,500	2,500	--	--	--	2,500	7,500	2,500	--	--	--
New Green River Oil and/or Gas Well Pads with 160-Acre Surface Density	2.0 acres	--	--	--	--	--	--	--	--	--	204	408	204
Wells Remaining to be Drilled under other Approved or Proposed Newfield Projects	2.0 acres[2]	--	--	--	241	48	48	--	--	--	--	--	--
Expansion of Existing Well Pads to Accommodate Deep Gas on 40-Acre Surface and Downhole Spacing	3.0 acres	--	--	--	--	--	--	--	--	--	1,539	4,617	1,539
Subtotal	**--**	**5,750**	**9,500**	**3,750**	**788**	**388**	**260**	**5,750**	**9,500**	**3,750**	**5,058**	**5,688**	**2,406**
Well Pad Conversions													
Existing Well Pads Converted to Water Injection Wells	-1.74 acres	--	--	--	--	--	--	--	--	--	1,144	--	-1,991
Subtotal Well Pad Conversions	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**-1,991**
Subtotal New Well Pads	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**5,058**	**5,688**	**2,406**
Net Total	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**5,688**	**415[3]**
Access Roads													
New Roads Co-located with Pipelines	40 feet[4]	243 miles	1,178	1,178	23.5 miles	114	114	243 miles	1,178	1,178	73 miles	354	354
Existing Roads with New Pipelines	10 feet[5]	363 miles	440	440	45 miles	55	55	363 miles	440	440	331 miles	401	401
New Roads Remaining to be Constructed under other Approved or Proposed Newfield Projects	40 feet	--	--	--	--	--	--	--	--	--	--	--	--

ALTERNATIVE		ALTERNATIVE A - PROPOSED ACTION			ALTERNATIVE B - NO ACTION ALTERNATIVE			ALTERNATIVE C - FIELD-WIDE ELECTRIFICATION			ALTERNATIVE D - AGENCY PREFERRED ALTERNATIVE		
Project Feature	**Size (disturbance width [feet] or acres/facility)**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**
Existing Roads Remaining to be Upgraded under other Approved or Proposed Newfield Projects	10 feet	--	--	--	--	--	--	--	--	--	--	--	--
Subtotal	**--**	**606 miles**	**1,618**	**1,618**	**68 miles**	**169**	**169**	**606 miles**	**1,618**	**1,618**	**404 miles**	**755**	**755**
Pipelines and Utility Lines													
Pipelines Co-located with New Roads	60 feet[6]	243 miles	1,767	736[7]	--	--	--	243 miles	1,767	736	73 miles	531	221
Pipelines Co-located with Existing Roads	60 feet[6]	363 miles	2,640	1,100[7]	--	--	--	363 miles	2,640	1,100	331 miles	2,407	1,003
Pipelines Co-located with New Roads	30 feet[8]				23.5 miles	85	57[9]		--	--	--	--	--
Pipelines Co-located with Existing Roads	30 feet[8]	--	--	--	45 miles	164	109[9]	--	--	--	--	--	--
Proposed Transmission Lines	30 feet	--	--	--	--	--	--	34 miles	124	62	--	--	--
Proposed Distribution Lines	20 feet	--	--	--	--	--	--	156 miles	N/A[10]	N/A	--	--	--
Subtotal	**--**	**606 miles**	**4,407**	**1,836**	**68 miles**	**249**	**166**	**796**	**4,531**	**1,898**	**401**	**2,938**	**1,224**
Central Facilities													
Compressor Stations (New/Upgrades)	10 acres	24	226	226	2	20	20	24	226	226	17	160	160
Gas Processing Plants	10.0 acres	1	10	10	1	10	10	1	10	10	1	10	10
Water Treatment and Injection Facilities	8/5 acres[11]	13	86	86	1	7	7	13	86	86	10	65	65
Gas and Oil Separation Plants (GOSPs)	22.0 acres	12	264	264	1	22	22	12	264	264	8	176	176
Fresh Water Collector Well	1.7 acres	1	**1.7**	**.7**	1	**1.7**	**.7**	1	**1.7**	**.7**	1	**1.7**	**.7**
Pump Stations	3/5 acres[12]	6	18	18	1	5	5	6	18	18	4	12	12
Generating Stations	5.0 acres	--	--	--	--	--	--	11	55	55	--	--	--
Subtotal	--	**57**	**604**	**604**	**7**	**64**	**64**	**68**	**659**	**659**	**41**	**423**	**423**
Total New Disturbance	**--**	**--**	**16,129**	**7,808**	**--**	**870**	**659**	**--**	**16,308**	**7,925**	**--**	**9,805**	**2,818**
Life of Project (LOP)		41 to 51 Years			28 to 38 Years			41 to 51 Years			39 to 49 Years		

ALTERNATIVE		ALTERNATIVE A - PROPOSED ACTION			ALTERNATIVE B - NO ACTION ALTERNATIVE			ALTERNATIVE C - FIELD-WIDE ELECTRIFICATION			ALTERNATIVE D - AGENCY PREFERRED ALTERNATIVE		
Project Feature	**Size (disturbance width [feet] or acres/facility)**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**	**Number or Miles**	**Initial (short-term) Surface Disturbance (acres)**	**Residual (long-term) Surface Disturbance (acres)[1]**
Water Requirements													
Drilling and Completion		1,150 acre-feet per year			322 acre-feet per year			1,150 acre-feet per year			908 acre-feet per year		
Dust Suppression during Construction		3 acre-feet per year			4 acre-feet per year			3 acre-feet per year			3 acre-feet per year		
Dust Suppression during Operations		75 acre-feet per year			10 acre-feet per year			75 acre-feet per year			66 acre-feet per year		
Waterflooding Infrastructure and Operations		2,738 acre-feet per year			548 acre-feet per year			2,738 acre-feet per year			4,176 acre-feet per year		
Total Water Requirement for Project		74,731 – 102,861 acre-feet			11,868 – 17,444 acre-feet			74,731 – 102,861 acre-feet			97,590– 140,010 acre-feet		
Workforce Requirements													
Workdays for Project		2,326,448			404,668			2,360,628			2,164,136		
Average Workdays per Year		125,651			116,810			127,447			124,036		
Average Number of Workers per Day		524			492			532			516		

[1] Residual disturbance calculations are based on the assumption that interim reclamation would be initiated and successful.
[2] For purposes of analysis, approximately half of the wells are assumed to be vertical wells drilled on existing well pads and half are assumed to be vertical wells drilled on new 2-acre well pads.
[3] The net total includes the 1991 acre decrease in surface disturbance as a result of well pad conversion.
[4] Initial disturbance assumes that a 100-foot wide disturbance corridor would be needed for construction, 40 feet of which would be utilized for new road construction, and 60 feet of which would be utilized for pipeline/utility line installation.
[5] Initial disturbance assumes that a 70-foot wide disturbance corridor would be needed for construction, 10 feet of which would be utilized for general road improvements, and 60 feet of which would be utilized for pipeline/utility line installation.
[6] Initial disturbance assumes that a 60-foot wide disturbance corridor would be needed for pipeline/utility line installation within new and existing road ROWs.
[7] Residual disturbance assumes that 35 foot wide portion of the original 60-foot wide disturbance corridor would be reclaimed leaving a 25-foot wide corridor for the long-term pipeline/utility corridor.
[8] Initial disturbance assumes that a 30-foot wide disturbance corridor would be needed for pipeline installation within new and existing road ROWs because fewer would be needed.
[9] Residual disturbance assumes that a 10-foot wide portion of the original 30-foot wide disturbance corridor would be reclaimed leaving a 20-foot wide corridor for the long-term pipeline corridor.
[10] Proposed distribution lines would be co-located within road and pipeline ROWs, so no additional disturbance would be associated with these facilities.
[11] Each new water treatment and injection facility would occupy a site approximately 8 acres in size. Existing water treatment and injection facility locations proposed for expansion would be increased in size by approximately 5 acres each.
[12] Each new pump station would occupy a site approximately 3 acres or 5 acres in size.

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2.8 ALTERNATIVES CONSIDERED BUT DISMISSED FROM ANALYSIS

All issues identified during scoping have been addressed in the range of alternatives carried forward for analysis. Alternatives C and D were specifically developed in response to issues raised by the BLM, Cooperating Agencies, and the public during both internal and public scoping. In addition, all alternatives considered during the alternative development phase were carried forward for full analysis. Therefore, there were no alternatives considered but dismissed from analysis.

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