PROJECT DESCRIPTION

LA BARGE PLATFORM EXPLORATION AND DEVELOPMENT PROJECT

EOG RESOURCES, INC.

EXXONMOBIL PRODUCTION COMPANY

CHEVRON U.S.A. INC.

WEXPRO COMPANY

DECEMBER 2009

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Acronyms

AO	authorized officer
APD	Application for Permit to Drill
AQD	Air Quality Division
BLM	Bureau of Land Management
CAP	Coordinated Activity Plan
COA	Conditions of Approval
CFR	Code of Federal Regulations
EIS	environmental impact statement
EOG	EOG Resources, Inc.
FEL	from east line
FLPMA	Federal Lands Policy and Management Act
FNL	from north line
FSL	from south line
FWL	from west line
LBP	La Barge Platform
N	north
NE	northeast
NEPA	National Environmental Policy Act
NOS	Notice of Staking
NOx	Nitrogen oxides
NW	northwest
R	Range
RCRA	Resource Conservation and Recovery Act
RMP	Resource Management Plan
ROW	right-of-way
SE	southeast
SW	southwest
T	Township
Tpy	Tons per year
USFS	United States Forest Service
TMD	total measured depth
TVD	total vertical depth
VOC	Volatile organic compounds
W	west
WDEQ	Wyoming Department of Environmental Quality
WOGCC	Wyoming Oil and Gas Conservation Commission

1.0 PROJECT OVERVIEW

EOG Resources, Inc., ExxonMobil Production Company, Chevron U.S.A. Inc., and Wexpro Company (collectively referred to as the "Operators") propose to explore for and develop potentially productive subsurface formations underlying oil and gas leases owned, at least in part, by the Operators within the La Barge Platform (LBP) area of northern Lincoln County and southern Sublette County, Wyoming. The Project Area consists of approximately 218,000 total acres. The Operators propose to drill, complete, produce, and eventually reclaim up to 838 new oil and gas wells on an estimated 463 new well pads as infill (vertical and horizontal), exploratory, or step-out wells to all productive formations, including the Almy, Transition zone, Mesaverde, Baxter, Frontier, Muddy, Dakota, Nugget, Bear River, and possibly other formations.

Target depths for the wells would range from approximately 1,000 to 10,000 feet. The productive life of each well would be up to 40 years. Although actual operations are subject to change due to conditions beyond the control of the Operators, each Operator plans to drill additional wells over the next 15 years. The total number of wells drilled would depend largely on factors outside of the Operators' control such as production success, engineering technology, economic factors, rig availability, and availability of commodity markets.

The following description is a conceptual representation of the Operators' future plans in the Project Area. The Operators would drill up to 263 wells vertically from new well pads and up to 575 wells either horizontally or directionally from new or existing well pads. The Operators plans to utilize a combination of vertical, directional, and horizontal drilling techniques in the Project Area will result in continued efficient development of remaining oil and gas reserves from the LBP. In addition, utilization of existing infrastructure to the extent reasonably possible will significantly minimize surface impacts over the life of project.

The Operators would utilize existing well pad disturbances and/or would co-locate new wells with existing wells throughout the Project Area to the greatest possible extent when drilling future horizontal or directional wells. The possibilities for locating new well(s) include:

- On an existing well pad, co-located with a producing well (may require additional construction to enlarge an existing pad);
- On a new well pad with multiple wellbores; and
- On a new one-well pad.

The average density of new surface well pads throughout the Project Area is one new well pad per each 1,263 acres, or one pad per two square miles of land. The types and anticipated corresponding numbers of new wells and new well pads proposed for this project are summarized in Table 1. The proposed wells would be distributed in geographic areas identified by the Operators within the Project Area, as shown on Map 1. Section 6.1 contains a description of wells and well pads proposed for each geographic area (Areas A through F) in the Project Area. The geographic areas were determined by the Operators based on unit boundaries and operatorship.

The drill depth and geologic characteristics of the target formation determine the type of drilling technology used for a particular well. In general, shallow formations would require vertical wellbores and the Frontier Formation would have both vertical and horizontal/directional wellbores.

Map 1. Project Area Boundary and Geographic Areas A through F

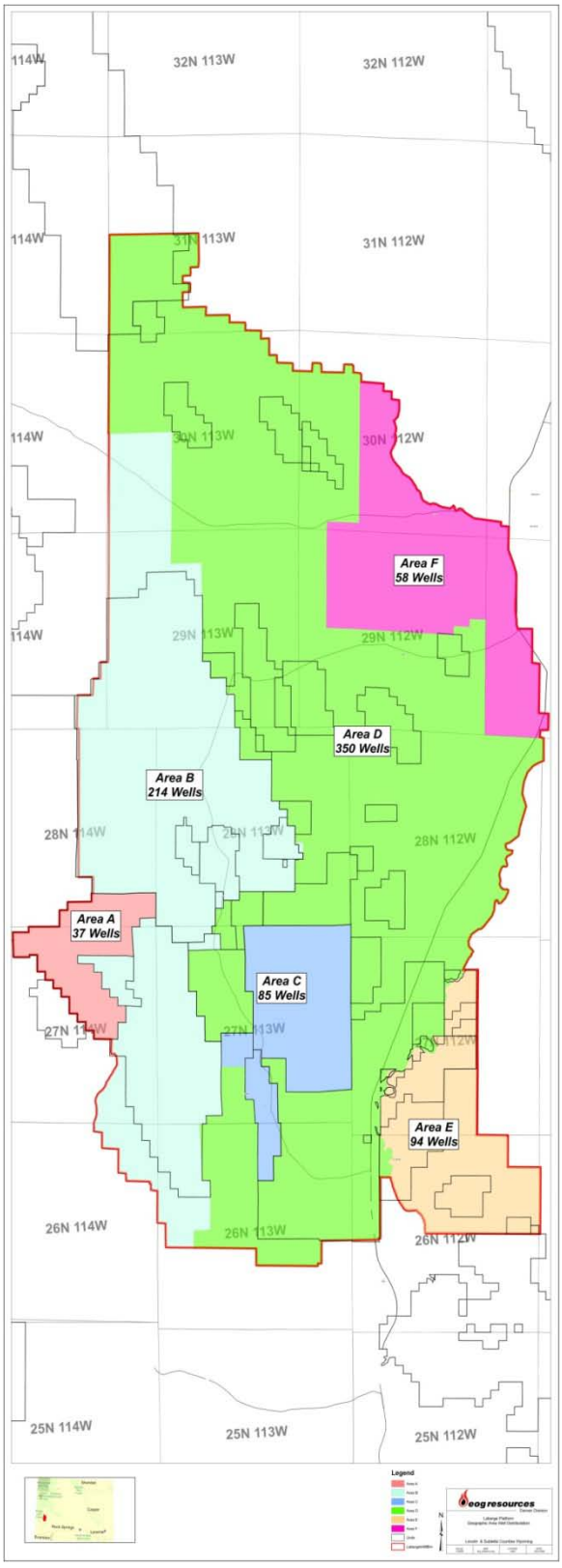

Table 1. Number of Wells by Drilling Technology and Formation

Type of Drilling Technology and Formation	New Wells	% of Total Well Count	New Well Pads
Vertical Frontier	128	15%	128
Directional/Horizontal Frontier/Baxter/Bear River	538	64%	182
Vertical Shallow Formations (Almy, Transition, Mesaverde)	172	21%	172
Total	**838**	**100**	**463**

The effective drainage area of vertical gas wells varies from 40 to 80 acres, due to geological and reservoir conditions. Within the Project Area, the Operators expect most vertical wells would be located at 80-acre surface density and downhole spacing, but there will be some variation. Where a horizontal Frontier or Baxter well is drilled, a well is anticipated to drain the natural gas from 160 to 320 acres, resulting in 2 horizontal wells per section (if 320 acres) or 4 horizontal wells per section (if 160 acres). The resultant effective spacing will be equivalent to 40 acres. The successful use of horizontal drilling would minimize surface impacts by effectively producing natural gas from an equivalent of two to four vertical wells.

The proposed shallow oil wells would continue at the present 10-acre vertical development because their shallow target formations and multiple productive intervals preclude the use of horizontal or directional drilling technologies. Operators may consider 5-acre spacing for oil well development in some parts of the Project Area, subject to regulatory approval where needed.

Project development would result in the construction of new roads and continued use of roads previously constructed and currently used in the Project Area. No major ancillary facilities are anticipated at this time. However, the need for new ancillary facilities would be analyzed on a case by case basis through the NEPA process if such a need is identified in the future. Production equipment at gas wells would be powered by currently installed electric power and natural gas. If feasible, some equipment requiring electricity would be powered by solar panels. Power lines would be needed to operate artificial lift equipment at new oil wells (see Section 6.10.1 for more information). Existing power lines to well pads would also continue to be used, and power lines to new locations may be installed on a site-specific basis.

Produced water from gas wells would be stored in a tank on the well pad and transported by truck to an approved disposal site. Vehicle traffic would be reduced by installing sufficiently large tanks to facilitate storage. Generally, use of 210 to 500-bbl tanks would allow Operators to empty a water storage tank only when necessary, greatly reducing project-related truck traffic. An average of 7 truck trips per day would haul produced water (see Section 6.10.3 for more information). Produced water and oil from the majority of oil wells would be transported via buried pipeline or truck to sales and/or existing central facilities and trucked from the central facility to an approved disposal site in the case of water and to sales in the case of the produced oil. Some oil wells may require on-site facilities, in which case the water would then be trucked to disposal from the site and the oil would be trucked or piped to sales.

2.0 PROJECT LOCATION

The Project Area is located within the Upper Green River Basin, 60 miles northwest of Rock Springs, Wyoming, and covers approximately 218,000 acres east and west of the Green River (**Map 1**). General public access to and within the Project Area is from U.S. Highway 189, State Highway 235, and Whelan

Road. Direct access would be via the existing road network, which consists of arterial roads and individual well access roads.

The Project Area is an existing oil and gas producing area on surface lands owned by the United States government, State of Wyoming, and private parties (Table 2). The Bureau of Land Management's (BLM) Pinedale and Rock Springs Field Offices administer federal lands and minerals in the Project Area.

Table 2. Project Area Surface and Mineral Ownership

Owner	Surface (approx. acres)	Minerals (approx. acres)
BLM	154,000	172,000
State of Wyoming	11,000	46,000
Private/Fee	53,000	
Project Area Total	**218,000**	**218,000**

The Project Area includes federal units in addition to non-unitized lands. Federal unit regulations require the lessees in the unit to designate a single operator whose actions and activities will benefit the interests of the majority of the leases committed to the unit. Having one designated operator for each unit provides significant benefits for managing surface resources and environmental values because BLM does not have to contend with multiple operators. On non-unitized federal leases, it is not uncommon to have multiple operators pursuing drilling on individual leases. Instead, a unified Plan of Development is required annually which allows orderly development of subsurface resources to occur while protecting environmental values and surface resources. Spacing rules are vacated for all federal exploratory units in Wyoming, including those in the Project Area, but subject to unit-specific setback requirements.

3.0 PURPOSE AND NEED

The purpose of the project is to:

- Allow the Operators to exercise their lease rights to reasonably drill and develop their leaseholds and extract the hydrocarbon resources from several hydrocarbon-bearing reservoirs, including the Almy, Transition zone, Mesaverde, Frontier, Baxter, Bear River, Muddy, Dakota, and possibly other formations.
- Evaluate the technical and economic viability of utilizing horizontal drilling in the Project Area to maximize production of the mineral resource while minimizing the amount of surface disturbance necessary to do so.
- Further define completion techniques associated with the proposed drilling technologies to economically produce hydrocarbons in the Project Area.
- Provide additional data with which to evaluate future well spacing.
- Provide additional data for use in evaluating the level of activity of future drilling in the Project Area.
- Ascertain the viability of drilling and completing throughout the year.
- Contribute to the available supply of natural gas, a clean-burning fuel.
- Generate federal and state taxes and/or royalty revenues.

- Support local economies by providing and maintaining employment opportunities and expanding the tax base.

4.0 MANAGEMENT PLAN CONFORMANCE

The proposed project is subject to conformance with the Pinedale Resource Management Plan (RMP) (BLM 2008) and the Green River RMP (BLM 1997). The Pinedale RMP (BLM 2008) states:

> The Approved RMP provides for accelerated development of known and existing oil and gas fields and resources, while maintaining viable wildlife habitats and open spaces in other areas. The Approved RMP also provides for site-specific management of intensive oil and gas development through field-level environmental analysis and decisions and implementation of operating standards and best management practices.

The Green River RMP (BLM 1997) states:

> The objective for management of the BLM-administered Federal minerals is to maintain or enhance opportunities for mineral exploration and development, while protecting other resource values (page 11).

Oil and gas extraction in the BLM Pinedale and Rock Springs field office areas is also guided by the decisions made in applicable BLM NEPA documents, including the Coordinated Activity Plan (CAP) for the Big Piney/LaBarge Area Environmental Assessment and Finding of No Significant Impact (BLM 1991) and the Enron Oil & Gas Company East LaBarge Infill Drilling Project Environmental Assessment and Finding of No Significant Impact (1992), which are incorporated by reference and available at the BLM field offices. Other NEPA documents include the Decision Record, Finding of No Significant Impact and Environmental Assessment for Mobil's Tip Top / Hogsback Unit Natural Gas Project (1994) and the Supplement for the 1995/1996 Drilling Program (1996).

5.0 DEVELOPMENT PLANS

The proposed wells and well pads would be distributed in geographic areas identified by the Operators within the Project Area, as shown on Map 1. Section 1.1 contains a description of wells and well pads proposed for each geographic area (Areas A through F) in the Project Area.

5.1 GEOGRAPHIC AREAS

Varying well densities and development strategies are proposed for each of the geographic areas shown on Map 1. The differences in development strategies are based on operatorship, types of wells proposed, and level of existing development and infrastructure. Table 3 presents a summary of the wellbores and well pads proposed for each geographic area. The Operators intend for their development plans to be specific to each identified geographic area.

Table 3. Plan of Development by Geographic Area

Geographic Area ID	Acreage	Well Count	New Well Pads
A	6,000	37	18
B	54,000	214	9
C	12,000	85	57
D	112,000	350	269

Geographic Area ID	Acreage	Well Count	New Well Pads
E	14,000	94	52
F	20,000	58	58
Total	**218,000**	**838**	**463**

5.1.1 Area A

Area A encompasses the Dry Piney Unit and consists of approximately 6,000 acres. Up to 37 gas wells are proposed to be drilled in this area over the 15 year timeframe of the proposed action. All of the wells in this area would be drilled to the Frontier formation using vertical wellbores. It is anticipated that approximately 18 new well pads may be constructed in Area A, though drilling from existing pads would be determined on a case-by-case basis based on geologic and economic conditions.

5.1.2 Area B

Area B encompasses the Hogsback and Tip Top Units, other units, as well as non-unitized land. Area B consists of approximately 54,000 acres. Up to 214 wells are proposed to be drilled horizontally to the Cretaceous Formations, including, but not limited to, the Muddy, Mowry, and Frontier formations over the next 15 years. The wells would be drilled from a combination of existing well pads and 9 new well pads. Existing well pads would need to be expanded to accommodate new wells, and four wells may be drilled from each new pad. Table 3 presents a summary of development plans for Area B.

5.1.3 Area C

Area C encompasses the Birch Creek and La Barge Units, totaling approximately 12,000 acres. Up to 85 wells may be drilled to the Baxter, Frontier, and Bear River formations in Area C over the next 15 years, which is expected to be comprised of 35 vertical wells and 50 horizontal or directional wells. Up to 57 new well pads may be constructed for drilling the 85 new wells proposed.

5.1.4 Area D

Area D is comprised of 112,000 acres within the Project Area, and encompasses the Green River Bend, North LaBarge Unit, numerous other units, and non-unitized land. Continued development of both oil and gas wells would occur under the proposed action. Up to 200 vertical or horizontal gas wells would be drilled on up to 119 new pads. Up to 150 vertical shallow oil wells would be drilled in this area on 150 new pads. A total of 350 wells could be drilled in this area over the next 15 years.

5.1.5 Area E

Area E encompasses the area east of the Green River in the Rock Springs Field Office management area, consisting of approximately 14,000 acres. The East LaBarge Unit, Stead Canyon Unit, other units, and non-unitized lands are included in this area. Up to 94 wells are proposed to be drilled in Area E on existing pads and up to 52 new well pads.

5.1.6 Area F

Area F is comprised of primarily state and private land within the Project Area. Of the approximately 20,000 acres in Area F, approximately 9,000 acres are leased and unleased federal acres. It is estimated that up to 58 federal wells may be drilled in this area over the life of the project, though specific detail of development within this area is unknown by the Operators participating in this EIS. The level of development in this area is based on a reasonably foreseeable scenario of 160-acre downhole spacing of

federal wells in this area. Due to lack of specific operator information, all wells in this area are assumed to be drilled vertically from new well pads.

The remainder of this Project Description applies to operations within the entire Project Area.

5.2 YEAR-ROUND DRILLING AND COMPLETIONS

The Operators propose to conduct drilling and completion operations throughout the year. To do so, the Operators request, as part of its Proposed Action, annual exceptions or waivers from surface use conditions that apply seasonal use timing limitations associated with individuals of the following species and/or their habitat:

- Big game, including pronghorn, mule deer, elk, and moose
- Greater sage-grouse

Each Operator would provide separate drilling plans each year for their specific geographic areas where exceptions from seasonal use timing limitations would be requested. The drilling plan would include details on use of existing pads for disturbance, traffic limitations, and remote monitoring. The drilling plan would be for specific geographic areas in which exceptions to winter stipulations would be requested. The winter drilling area may remain the same over multiple years, or may shift depending on drilling targets, production results, or new information. The winter drilling geographic area would be determined in consideration of wildlife habitat and population needs. Permitting and construction of new well pads and access roads would occur prior to winter restriction timeframes so that only drilling, completion, installation of production facilities, and production operations would occur during the winter.

The Operators are committed to mitigating potential impacts associated with winter drilling and will consider mitigation measures to address wildlife mortality along Calpet Road, habitat restoration, and other projects. Further details on the winter activity plan process, including mitigation, would be determined through consultation with the BLM and the cooperating agencies.

6.0 PROJECT OPERATIONS

6.1 PRE-CONSTRUCTION ACTIVITIES

Prior to the start of construction activities, the Operators will:

- Submit site-specific applications (Notice of Staking [NOS], Application for Permit to Drill [APD], Right-of-Way [ROW] application).
- Survey and stake the location.
- Submit detailed construction plans, as needed.
- Participate in an onsite evaluation.
- Perform cultural resource, biological, and/or other surveys, as required.

Construction or surface disturbing activities will occur generally during daylight hours only and only after approval of an APD. Infrequent circumstances may require construction to occur during nighttime hours.

6.2 ACCESS ROADS

Project development would result in the use of new roads as well as roads previously constructed and currently used in the Project Area. To avoid unnecessary surface disturbance and minimize impacts from well pad siting and road construction, the Operators would utilize satellite or other aerial imagery to digitally locate the existing infrastructure, including well pads, roads, and pipelines, and determine the most suitable locations for new surface disturbance.

The digital aerial spatial data would allow the Operators to efficiently plan new well and access road locations by:

- Maximizing the use of the existing road system;
- Minimizing the number of loop roads;
- Minimizing the crossing of side slopes greater than 25 percent;
- Minimizing profile grades; and
- Minimizing drainage crossings, with emphasis placed on drainages with potentially large runoff flows and floodplains.

In addition, the Operators will submit a Transportation Plan to the BLM concurrent with EIS development to more clearly identify measures taken to minimize road and traffic-related impacts during project development.

The Operators would construct new roads and well sites to standards described in the BLM publication *Surface Operating Standards for Oil and Gas Exploration and Development, 4th Edition*, called the Gold Book (BLM and USFS 2007) and in BLM Manual 9113 – Roads, and would incorporate site-specific best management practices to be determined at the onsite inspection. Travel during construction would be restricted to the 40-foot wide ROW unless modifications must be made to accommodate slope conditions.

Roads would be built with standard cut-and-fill and grading techniques and maintained to provide year-round access. All construction materials for project access roads would consist of native borrow and soil accumulated during road construction. Access roads would be surfaced with gravel or other appropriate material unless sufficient natural gravel exists, as determined by the AO on a site-specific basis. Gravel and rock would be obtained from existing permitted or private sources. Road crossings would incorporate culverts, as needed and/or required. The Operators would utilize materials such as rip rap to prevent erosion and head cutting from culverts and other drainages. Drainage ditches and culverts would be designed to prevent the accumulation of silt or debris and will not be blocked by the roadbed. Water would be diverted from the roadway at frequent intervals, as necessary.

Existing roads that require upgrading would also meet standards appropriate to the anticipated traffic flow and all weather road requirements. Upgrading may include ditching, drainage, graveling, crowning, and capping the roadbed as necessary to provide a well-constructed, safe roadway. Upgrading will not be performed during muddy conditions.

Most new access roads would be constructed as laterals from existing roads. The amount of surface area needed for roads depends upon topography and the types of loads they would carry. Road ROWs in the Project Area are typically 40 feet wide. The running surface of access roads is 16 to 20 feet wide. Access road lengths would vary according to the location of a specific well and its relation to the topography and existing road network. The Operators estimate that the average well pad access road length would be approximately 0.12 mile but a few individual roads may be up to 2 miles long. The exact location of well access roads would be determined at the time of the onsite with the appropriate surface management agency.

6.3 WELL PADS

Well pads would be constructed from the native sand/soil/rock materials present. Mineral materials would not be required. Locations would be leveled by balancing cut and fill areas. Construction practices may include blasting or ripping to achieve a level pad. Blasting may be required when bedrock is near the surface. Cut-and-fill slopes would be designed to allow for retention of the topsoil. Topsoil and native vegetation would be removed and stockpiled for use in the reclamation process, including the re-establishment of vegetation.

A well pad would typically include a 6 to 8-foot wide cellar to allow access to casing heads, mouse and rat holes adjacent to the wellbore to accommodate drilling operations, a flare pit, and a reserve pit. A fenced reserve pit, approximately 10 to 12 feet deep, would be excavated within the pad to temporarily store drilling fluids, cuttings, and water produced during drilling operations. The dimensions of pits vary according to well depth and size and shape of the location, but typical dimensions are 135 feet by 60 feet. All reserve pits are lined and padded, as appropriate and necessary to prevent tearing and/or puncturing of the liner. Each pit would be constructed in a way that minimizes the accumulation of surface runoff into the pit through the use of strategically placed subsoil/topsoil storage areas and/or the construction of berms and diversion ditches. If the Operators plan to drill more than one well from a single pad, the reserve pit would be re-used for the following wells. Fluids in the reserve pit from the first well would be allowed to evaporate and be transported off the location by truck for reuse in drilling operations or to an approved disposal facility. The Operators would attempt to determine whether a subsequent well would be drilled from a pad within six months of drilling the first well. In general, the Operators would not perform interim reclamation until all wells are drilled on a pad. If, at the end of six months, an Operator has not performed interim reclamation because a subsequent well had not been drilled, the Operator would either reclaim the part of the well pad not necessary for operation of the first well or would contact the AO to determine a future course of action. The fencing surrounding the pit would remain and be maintained to prevent access by range stock or wildlife until the reserve pit is reclaimed.

Operators would avoid construction in the 100-year floodplain of the Green River. Operators would employ a professional hydrologist or utilize persons trained by the professional hydrologist to determine the location of the floodplain where the location of the floodplain is questionable. No permanent structures would be constructed within the floodplain boundary unless it can be demonstrated on a case-by-case basis that there is no physically practical alternative. Reserve pits would be replaced by closed loop drilling systems in locations where constructing a reserve pit would interfere with the water table, as determined at the time of permitting a well.

Access road and well pad construction typically takes 3 to 10 days, but could be longer depending on terrain and site limitations. Between two and eight workers may be present on location during construction activities at any given time, depending on availability and types of equipment and specific well construction requirements. Personnel would access the location using an average of three light trucks each day during construction of the access road and well pad. Construction equipment may include bulldozers, motor graders, scrapers, backhoes, and trenchers.

The size and dimensions of a drill pad would depend on topography and specific well needs, such as the drilling rig to be used. In general, shallow vertical wells require smaller well pads (e.g., 1 acre) than deeper vertical and/or horizontal wells (e.g., up to 10 acres). The average well pad size for wells in the Project Area, including both deep and shallow wells is 1.8 acres. Drilling a horizontal or directional well would not result in significant differences in construction procedures, but would typically require a larger pad size to accommodate a larger drilling rig capable of reaching the measured depths typically required for a horizontally drilled Frontier well. The traditional single-well location design that has been utilized in the Project Area in the past would be modified to drill more than one well on a shared location. If a second well were to be drilled from an existing pad, an estimated additional 0.5 acre would initially be required. Multi-well pads in the Tip Top and Hogsback Units may be as large as 10 acres to accommodate numerous wells.

Long-term disturbance would be the amount of surface remaining on the well pads after the reserve pit and other areas unnecessary for ongoing and future operations are reclaimed. After interim reclamation, long-term disturbance associated with an average single-well pad would be approximately 0.50 acre. Long-term disturbance associated with an average multi-well pad would increase by 0.25 acre for each new well. Long-term disturbance for multi-well pads in the Tip Top and Hogsback Units may be up to 4 acres to accommodate production facilities for multiple wells.

6.4 DRILLING

Following construction of the access road and well pad, a drilling rig would be transported to the well site and erected on the well pad. The Operators anticipate that no more than 12 drilling rigs would be used at any one time to drill the project wells. Multiple wells on pads would likely, but not necessarily, be drilled sequentially. Operators would, however, perform interim reclamation on all well pads as soon as possible after wells are placed on production. Also refer to the section describing "interim reclamation."

Wells would be drilled utilizing conventional, mechanically powered mobile drilling rigs. The rig would be erected at the drill site after the conductor pipe has been set. Drilling operations for vertical wells would typically consist of drilling surface hole, running and cementing surface casing, drilling production hole, and running and cementing production casing. Occasionally intermediate casing would also be run. Intermediate casing would also be required on horizontal wells in most cases. The rig would be dismantled and demobilized from the location after production casing is run and cemented.

Drilling fluids consist of a fresh water/gel mixture, with water being the main constituent. Drilling fluids would be re-used for subsequent wells to the extent possible; however, Operators cannot estimate the amount of fresh water that would be saved by such re-use at this time. Formation stabilizing and hole cleaning materials may be added to the drilling fluid to achieve borehole stability and minimize possible damage to the gas producing formations. Oil based drilling fluids are not anticipated to be utilized for horizontal drilling operations based on the Operators' prior experience with horizontal drilling in the Frontier formation. No hazardous substances would be placed in the reserve pit. Reserve pits would be constructed so as not to leak, break, or allow discharge and in accordance with APD COAs. The reserve pit would be fenced on three sides during drilling operations and on the fourth side when the rig moves off the location. Fences would be constructed according to BLM requirements and as described in Onshore Order #7.

During drilling operations, a blow out preventer would be installed on the surface casing and intermediate casing, as required; to provide protection against uncontrolled entry of reservoir fluids into the wellbore should reservoir pressures exceed the hydrostatic pressure of the wellbore fluid. Such equipment would conform to regulatory requirements. In addition, a flow control manifold consisting of manual and hydraulically operated valves would be installed at ground level per regulatory requirement.

Prior to setting production casing, open hole electric and radioactive logs may be run to evaluate production potential. If deemed economically justified, steel production casing would be run and cemented in place in accordance with the well design and as specified in the APD and COAs. Evaluation logs may be run subsequent to setting and cementing production casing in lieu of open hole logs if approval has been granted by the regulatory agency.

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 the pressure requirements anticipated during completion and production operations. All casing would be new or reconditioned and tested, in accordance with applicable regulations.

Duration of drilling operations on a given well can vary greatly depending on depth and conditions encountered while drilling. A vertical Frontier well typically takes 7 to 10 days to drill. Frontier horizontal wells typically require approximately 20 to 45 days to drill, depending on directional complexity, hole conditions, and length of lateral. Drilling a vertical shallow well typically requires approximately 4 to 10 days, which is primarily dependent on hole conditions that can vary significantly within the Project Area. Drilling operations require approximately 8 to 10 personnel and six vehicles on location at any given time during normal operations. An additional 10 to 15 personnel and six vehicles are required on location to install and cement production casing.

6.5 COMPLETION AND TESTING

A typical cased wellbore in the Project Area consists of conductor pipe, surface casing, and production casing for vertical wells, and generally includes intermediate casing for horizontal wells. The surface, intermediate, and production casing/cementing programs would be designed to isolate and protect shallower formations and aquifers from the production stream and to minimize the potential for migration of fluids and pressure communication between formations. Alternative completion techniques in the horizontal portion of the wellbore may call for uncemented liners with no external isolation packers, uncemented liners with isolation packers, cemented liners/production casing, or other configurations that become viable with changing technology.

Upon release of the drilling rig, completion operations would commence utilizing a well servicing rig. Initial completion operations may also be conducted utilizing cased hole wireline equipment rather than a well servicing unit or coiled tubing unit, until such time that production tubing is installed in the well or other operational requirements dictate the use of a well servicing rig. In general, the completion of vertical wells consists of perforating the production casing, productivity and/or formation pressure testing if deemed necessary, stimulation of the formation(s) utilizing hydraulic fracturing technology, flow back of fracturing fluids, flow testing to determine post fracture productivity, and installation of production equipment to facilitate hydrocarbon sales. Horizontally drilled wells could be completed utilizing a variety of completion techniques depending on the mechanical configuration of the lateral. In general, based on current technology and well performance from existing horizontally drilled wells on the LBP, multiple stage stimulations in laterals with cemented production casing would be the most likely completion strategy.

Fracture fluids are recovered and hydrocarbons may be flared during testing operations, which are conducted on an as needed basis. Flared gas volumes are measures in accordance with BLM and WOGCC rules. Current fracture technology utilized in the Project Area includes the use of inert gases in the fracturing fluid, which minimizes the ability to employ “flareless completion” practices during early stage flow back following stimulation. Hydraulic fracture stimulation is required on the majority of wells in the Project Area in order to enhance productivity. Numerous combinations of fluids and proppants have been used historically in the Project Area in the effort to optimize stimulation. Currently, the most common stimulation technique utilizes gelled fresh water, inert gas (carbon dioxide or nitrogen), and fracture proppants to provide the conductivity necessary for productivity improvement. Sand is typically used as a proppant in the stimulation process, depending on the design criteria of individual treatments. Gels and other additives are utilized to increase fluid viscosity to ensure successful stimulation. The fracturing fluid is pumped down the wellbore through the perforations in the casing, and into the formation. Sufficient rate and pressure are reached to induce a fracture in the target formation. No diesel is used in this process. The proppant carried in the fluid serves as a bridge to keep the created fracture open and to provide a flow path that allows reservoir fluids to move more readily into the wellbore.

Post stimulation flow tests allow for recovery of stimulation fluids and evaluation of well productivity. Duration of the tests vary depending on individual well performance, but typically are conducted only long enough for fluid rates to drop to levels that allow the use of permanent production equipment and to reduce inert gas content to meet sales gas standards of third party gatherers. Flaring is typically conducted over a period ranging from 1 to 3 days, depending on the amount of water in the flow back stream. Flared gas is measured using choke nipple calculations or through a temporary flow test separator and metering facility. Flaring takes place at the end of a horizontal flow line placed at a temporary pit designed for that specific purpose or at a vertical flare stack. Flaring occurs at a distance from the wellhead that ensures equipment and structure protection and personnel safety. Following the initial flow period, the well will be shut in until facilities are in place to allow the well to be placed on sales. In some cases, production facilities would be installed prior to completion in order to provide the capability of turning the well to

sales immediately following testing. Fluids, primarily water, recovered during flow back operations will be contained in the reserve pit or tanks on location until they are disposed of at disposal wells.

Completion and testing operations require approximately 3 to 10 days to perform, but may be longer depending on the complexity of the completion program. Two to 30 people and 1 to 20 vehicles are required on location, depending on the type of operation occurring at any particular time.

6.6 WATER USAGE SUMMARY

In addition to water used for drilling and completion purposes, fresh water will also be used for hydrostatic testing of the gathering lines and for dust abatement and soil compaction during construction. All water will be obtained from permitted sources including:

- Green River #1 Water Haul located in Lot 5, Section 5, T26N, R113W, Lincoln County, Wyoming.
- Middle Piney Creek Water Haul located in the northwest quarter of the southwest quarter of Section 11, T29N, R113W, Sublette County, Wyoming (S Wells).
- Middle Piney Water Haul #2 located in Section 32, T30N, R113W, Sublette County, Wyoming (S Wells).
- Green River Bend Unit Water Source Well #1 located in Section 31, T27N, R112W (SE/NW).
- Tip Top Water Source Well #1 located in Section 28, T28N, R113W (SE/NE).

No new water source wells are proposed as part of this project. Water may be recycled for use in drilling, completion, workover, well abandonment, and hydrostatic pipeline testing operations. Stimulation fluids recovered during flow back and subsequent production operations will be temporarily contained in the reserve pit or in tanks on location and subsequently disposed of in accordance with requirements as discussed elsewhere.

Depending on the formation and type of well, between 2,000 and 14,000 barrels of water (one barrel = 42 gallons) are needed to perform drilling operations; however, when appropriate and approved by the appropriate regulatory authority, some water may be conserved by the reuse of some of the drilling fluids in subsequent drilling operations. Approximately 2,500 to 5,000 barrels of water are typically required to complete vertical Frontier wells, and 2,500 barrels to complete vertical shallow wells. Up to 15,000 barrels of water will be needed to perform completion on Frontier horizontal wells, depending on the number of stimulations required on an individual well. Horizontal wells typically require a substantially larger number of fracture stimulations due to the length of completion interval relative to a vertical well.

Up to 50 barrels of water may be used for pressure testing each gas gathering pipeline, depending on length. After testing is completed, the water will be recovered and reused for additional testing or other purposes or will be disposed of in a permitted commercial or Operator owned facility.

Up to 500 barrels of fresh water are typically used per mile of access road to mitigate fugitive dust resulting from construction operations and to aid in compaction of the newly disturbed soil. This water is applied to the access road and well pad only. A small amount of the estimated 500 barrels may be used during drilling operations during the dry summer months. Table 4 summarizes the fresh water that may be used for the project.

Table 4. Estimated Water Use Summary

	Frontier Wells		Shallow Wells[1]
	Vertical	Horizontal	Vertical
Drilling (barrels/well)	6,000	14,000	2,000
Completion (barrels/well)	5,000	15,000	2,500
Number of Wells	91	575	172
Water Use (acre-feet)	95.2	1586.4	73.6
Subtotal = 1755.2 acre-feet			

Other Water Uses			Amount (acre-feet)
Hydrostatic Testing	50 barrels/pipeline	463 gathering lines[2]	2.2
Dust Abatement	500 barrels/mile of access road	52.6 miles of access roads	2.5
Subtotal			**4.7**
Project Total = 1759.9 acre-feet			

[1] Shallow wells include Almy, Transition Zone, and Mesaverde

[2] One gathering line assumed for each wellbore.

6.7 MATERIALS MANAGEMENT

A variety of chemicals, including lubricants, paint, and additives, are used to drill, complete, and produce a well. Some of these chemicals contain constituents that may be hazardous. Hazardous materials include some greases or lubricants, solvents, acids, paint, and herbicides, among others. Potentially hazardous substances used in the development or operation of wells are kept in limited quantities on well sites and at the production facilities for short periods of time. Materials would not be stored at well locations during drilling operations. The transport, use, storage and handling of hazardous materials would follow the procedures specified by the Occupational Safety and Health Act and by the U.S. Department of Transportation under 49 CFR, Parts 171–180. U.S. Department of Transportation regulations pertain to the packing, container handling, labeling, vehicle placards, and other safety aspects.

None of the chemicals that would be used meet the criteria for being an acutely hazardous material/substance or meet the quantities criteria per BLM Manual 1703 – Hazard Management and Resource Restoration. Chemicals subject to reporting under Title III of the Superfund Amendments and Reauthorization Act in quantities of 10,000 pounds or more would not be used, produced, stored, transported, or disposed of annually during the drilling, completion, or operation of any well in the Project Area. In addition, no extremely hazardous substance, as defined in 40 CFR 355, in volumes that exceed threshold quantities, would be used, produced, stored, transported, or disposed of while producing any well.

6.8 WASTE MANAGEMENT

Most wastes that would be generated at well locations are exempt from regulation by the Resource Conservation and Recovery Act (RCRA) under the oil and gas exploration and production exemption. Exempt wastes include those generated at the wellhead through the production stream and gas plant. They include produced water, drilling mud, well completion/workover fluids, and soils affected by these exempt wastes. Non-exempt wastes may include spent solvents, discarded lubricants, paints or other substances that contain hazardous materials as defined by RCRA.

Operators develop and maintain Spill Prevention Control and Countermeasure Plans for wells in the Project Area, as required by regulation, to prevent and contain accidental releases.

6.9 INTERIM RECLAMATION

Operators would adhere to the commitments outlined in the La Barge Platform Project Reclamation Strategy (to be provided separately). The Reclamation Strategy provides additional detail on the Operators' commitment to perform reclamation in a way that allows the BLM to meet its objectives while providing Operators with the flexibility to implement reclamation effectively in cooperation with the BLM and reclamation experts. The purpose of reclamation planning is to incorporate measures that will support and return as much of the disturbed acreage in the Project Area to its pre-disturbance condition as quickly as feasible upon conclusion of drilling and completion operations on well pads.

Operators would perform interim reclamation in compliance with Onshore Order # 1. Reserve pits would be reclaimed according to the requirements specified in the approved APD after the pit is dry or the fluids have been removed. Synthetic liners would be handled according to BLM standards before backfilling the reserve pit. The reserve pit, portions of the well location and access road not needed for production operations, and pipeline ROWs would be rehabilitated according to the requirements specified in the approved APD and COAs.

If an Operator plans to drill multiple wells from a single pad, the reserve pit may be re-used for more than one well. Fluids in the reserve pit from the first well would be allowed to evaporate, transported off the location by truck, and either reused at another pad or disposed of. The Operator would attempt to determine whether a subsequent well would be drilled from a pad within six months of drilling the first well. In general, an Operator would not perform interim reclamation until the subsequent well(s) were drilled. If, at the end of six months, an Operator has not performed interim reclamation because a subsequent well had not been drilled, the Operator would either reclaim the part of the well pad not necessary for operation of the first well or would contact the AO to determine a future course of action.

During the time that a reserve pit is not reclaimed, the fencing surrounding the pit would remain and be maintained to prevent access by range stock or wildlife. Operators would utilize fencing, as needed, to surround reclaimed areas to protect new vegetation resulting from interim reclamation from grazing livestock and wildlife

6.10 PRODUCTION

Operators would continue to utilize the existing ancillary facility infrastructure within and near the Project Area to the extent possible, including water disposal and treatment facilities, compression facilities, and gas gathering and transmission pipelines. No new major ancillary facilities are planned as part of this proposal. However, the need for new ancillary facilities would be analyzed on a case by case basis through the NEPA process if such a need is identified in the future.

6.10.1 Well Production Facilities

Well production facilities would be installed as shown on an approved APD, with secondary containment structures built to conform to applicable requirements. Facilities installed on a well pad would differ according to whether the well would be producing gas or oil.

Facilities on the gas well pads may include wellhead valves and piping, separation, dehydration, metering equipment, a combined oil and water production tank, a dehydrator condensation catchment container, air emissions control equipment, a methanol storage tank and pump, and telemetry equipment. Duplicate facilities may be installed on a pad where production from individual wells cannot be commingled due to ownership differences or regulatory requirement. Production equipment at gas wells would be powered by natural gas, although equipment requiring electricity would be powered by solar panels. All gas would be measured electronically. Telemetry equipment would be used to improve well evaluation and operational efficiency, and to minimize well visits. Studies indicate that well site visits may be reduced by as much as 50 percent after the installation of telemetry (BP 2007). Production pits would not be used. Plunger lift equipment is typically installed on gas wells to provide artificial lift when production volumes drop to a level that prevents efficient removal of liquids from the wellbore using reservoir energy alone. Other types of artificial lift may be considered during the approval of an APD or subsequent to putting a well on production, including types that may result from new technologies.

Electric motors would power pumping units for oil wells. Existing primary electric line infrastructure would supply the electricity with the exception of remote locations outside the existing electrical infrastructure. Secondary electric lines would typically be installed to each new producing oil well. These secondary lines would originate from offset 10-acre wells that have existing electric lines in place to power their pumps. Electric lines to each new producing oil well would be overhead (above-ground) or buried, depending on the specific circumstances of each location. Electric lines would average 0.25 mile in length for each oil well, potentially resulting in approximately 43 miles of new electric lines in the Project Area. Above-ground electric lines would be equipped with raptor perch avoidance devices.

6.10.2 Pipelines

Gathering lines made of steel or other durable materials would typically be installed below the surface to transport the produced gas from the new wells to the gas pipeline system operated by Williams Field Services and/or Questar Gas Management Company. Operators will also consider installing surface pipelines where necessary to reduce erosion. The gathering lines consist of pipes with a 2 3/8 to 6 5/8-inch outside diameter and, in general, would be located adjacent and parallel to well access roads where possible to minimize surface disturbance. The exact location of a gathering line would be determined at the time of the onsite inspection with the appropriate surface management agency. Additional compression capacity to support project wells is not anticipated. The potential reduction of pressure on some gathering systems may require a change in the type and size of compressors utilized to transport gas, but significant changes in horsepower requirements are not anticipated as a result of this project.

Construction operations would be confined to the ROW corridor approved in ROW applications. Pipeline construction consists of trenching, pipe stringing, bending, welding, coating, lowering pipeline sections into the trench, and backfilling. The pipeline trench would be mechanically excavated with a backhoe or trencher to a minimum depth of 48 inches. The trench would be approximately 18 to 20 inches wide. Newly constructed pipelines would be hydrostatically tested to ensure structural integrity. Drilling water may sometimes be used for hydrostatic testing. Up to 50 barrels of water may be used for hydrostatic testing for each 0.25-mile gathering line. Water from drilling operations that is not used for hydrostatic testing would be disposed of as approved by the BLM and/or the State. Pipelines may also be air tested in some cases.

Typical construction widths for a pipeline are 40 feet when not adjacent to a road, decreasing to 30 feet when adjacent to an existing or new access road. Operators would reclaim pipeline routes as specified in APD or ROW approvals. Pipeline installation would result in short-term disturbance but would not result in long-term disturbance after reclamation is complete.

6.10.3 Produced Water

Relatively small amounts of fluids, including water, are produced in the Project Area (as compared to other fields in the Pinedale Field Office area). Gas wells in the Project Area produce an average of 54 barrels of water during a month, after stimulation fluids from completion operations have been recovered. In general, use of 210 to 500-bbl tanks allows Operators to empty a water storage tank infrequently for long term well operations, greatly reducing project-related truck traffic. Produced water is not stored in a reserve pit except temporarily during testing operations. During production operations, produced water would be stored in a 210-barrel (bbl) to 500-bbl tank, depending on the amount of produced water volume from a given well, on the well pad and transported by truck to a permitted disposal site. Disposal sites are located at the GRBU #1 Tank Battery in Section 36, Township 27N, Range 113W, the BNG #3 water disposal facility in Section 28, Township 28N, Range 113W, the LaBarge Saltwater Disposal Facility, the Birch Creek Unit E Battery, or other previously approved disposal sites located in the Project Area.

All vessels containing stored fluids or other chemicals needed for production operations would be enclosed within a berm constructed with an impenetrable barrier such that any spilled fluid would be completely contained within the bermed area. The surface beneath the bermed area would be lined with clay or other synthetic material to prevent spilled fluids from migrating to the surface soils and to the subsurface.

6.10.4 Workovers

Periodically, a workover on a well may be required. A well servicing rig is generally utilized during workover operations to perform various tasks such as wellbore or surface equipment repairs, reservoir evaluation, formation evaluation by wireline, or stimulation treatments to restore or enhance well performance. Workover operations are typically performed during daylight hours and are of short duration; however, depending on the scope of the work to be performed, workover operations can sometimes take from several days to several weeks to be completed. Unless fracture stimulation is necessary, workover operations typically require from 5 to 10 workers on location at any given time. During fracture treatments, an additional 10 to 20 workers could be present on location. Additional surface disturbance is rarely necessary to conduct workover operations; however, temporary pits may occasionally be utilized to store fluids. Approval from the BLM AO would be requested should the need for new surface disturbance arise.

6.10.5 Final Reclamation

Abandonment of the well and its facilities would occur at the end of the productive life of a well in compliance with applicable federal and state regulations as well as the COAs to the APDs. The Operators would adhere to the commitments outlined in the La Barge Platform Project Reclamation Strategy (to be submitted).

Operators would cut off the casing at the base of the cellar or 3 feet below the final graded ground level, whichever is deeper, and cap the casing with a metal plate a minimum of 0.25 inch thick. The cap would be welded in place with the well name and location engraved on the top. The cap would be constructed with a weep hole and placed 3 feet below ground level or to BLM specifications.

All surface equipment would be removed from the site. The surface would be recontoured to its original appearance, to the extent possible. Topsoil that was stockpiled during construction would be distributed on the surface of the former well pad to blend the site with its natural surroundings.

All disturbed areas would then be planted with a seed mixture of native grass and plant species as specified by the appropriate surface management agency. Seed mixtures applied during rehabilitation operations would comply with the specifications of the appropriate surface management agency. Upon completion of reclamation operations, an Operator would notify the AO when the location is ready for inspection. Operators recognize that final abandonment would not be approved on federal lands until the surface reclamation work required by the approved APD or approved abandonment notice has been completed by the BLM.

6.11 SURFACE DISTURBANCE SUMMARY

Project development would result in surface disturbance. Short-term disturbance refers to initial disturbance prior to interim reclamation of the reserve pits, unused portions of the well pads and roads, and the pipeline route. Long-term disturbance refers to disturbance of the surface associated with the life of a well in addition to the running surface of access roads. The following assumptions were made to estimate surface disturbance.

Area B

- A typical new well pad in the Tip Top and Hogsback area requires an initial disturbance of approximately 10 acres to accommodate multiple wells, and long-term disturbance of approximately 2.5 acres after interim reclamation.
- Placing new wells on existing pads requires approximately 4 acres of new disturbance with long-term disturbance of 2.5 acre after interim reclamation.

Areas A, C, D, E, and F

- A typical well pad in the Project Area requires an initial disturbance of approximately 1.8 acres and long-term disturbance of approximately 1.3 acres after interim reclamation.
- A second well on a pad would require an additional 0.5 acre for drilling and completion, and 0.25 acre after interim reclamation.
- Average access road length would be 600 feet, resulting in 0.55 acre of short-term surface disturbance and 0.22 acre of long-term disturbance, corresponding to the running surface of the road.
- A Frontier horizontal well would typically require an additional 0.25 acre to accommodate a larger drilling rig.
- Initial surface disturbance for a single vertical or directional well pad to shallow formations would average approximately 1.6 acres.
- Long-term disturbance associated with each single well pad would be approximately 0.5 acre. Long-term disturbance associated with an average 2-well pad would be approximately 0.75 acre for each shared well pad. Pads with more than 2 wells would be proportionately larger.
- For the purpose of calculating surface disturbance, it is assumed that all co-located wells would be placed on Frontier vertical well pads.
- Access road construction width would be 40 feet. Reclamation would be initiated after construction, and long-term bare ground from access roads would be 20 feet in width.
- Pipeline construction width would be 30 feet, and long-term disturbance from pipelines would be zero. Pipelines would be installed parallel to access roads and pipelines are assumed to be approximately 600 feet long.

- An estimated 100% of all new vertical wellbores would be located on new well pads; approximately 54% of all new horizontal or directional wells would be located on new well pads.

Table 5 displays a summary of estimated project-related new disturbance.

Table 5. Summary of Surface Disturbance

Facility	Count/Length	Short-term Disturbance (acres)	Short-term % of Project Area	Long-term Disturbance (acres)	Long-term % of Project Area
Well Pads	463 pads	1,317	0.6%	521	0.2%
Roads	52.6 miles	255	0.1%	128	0.05%
Pipelines	52.6 miles	191	0.08%	0	0%
Total		**1,763**	**0.78%**	**649**	**0.25%**

Project implementation would result short-term surface disturbance of less than 1% of the Project Area. Long-term surface disturbance after interim reclamation would be approximately 649 acres, or 0.25%, of the Project Area.

7.0 OPERATOR-COMMITTED DESIGN FEATURES

Operators will adhere to all lease conditions, in addition to all federal and state laws, regulations, and policies. In addition, the Operators are committed to the following environmental protection measures, many of which are currently implemented in the LBP Project Area. The Operators also anticipate that additional environmental protection measures and mitigation measures may be identified during the EIS process and added to the Proposed Action at a future time, or may be discussed and agreed to during onsite inspections at the time of APD submittal.

7.1 AIR QUALITY

- Operators will comply with the Wyoming Department of Environmental Quality – Air Quality Division (WDEQ-AQD) policies and rules. Numerous air quality control measures are being evaluated for use in the Project Area, including the following:
    - Operators are evaluating the use of desiccant dehydrators in lieu of glycol dehydrators. Glycol dehydrators vent methane, VOCs, and HAPs to the atmosphere from the glycol regenerator, bleed natural gas from pneumatic control devices, and burn natural gas in the glycol reboiler. Glycol dehydration units account for almost 56% of VOCs emitted by production facilities; therefore, replacing these units could result in significant decrease in VOC emissions over time.
    - Operators are evaluating the efficacy of plumbing trace pump exhaust (VOCs) back into the burner of the separator. By doing so, Operators would reduce the pneumatic pump emissions to zero and reduce makeup gas that would normally be used to heat the burner. Pneumatic pump operations currently account for over 30% of volatile organic compound (VOC) emissions on facilities in Sublette County. This technique, therefore, has the potential to reduce VOC emissions by up to 30% from production equipment currently being used within the Project Area.

- Operators are evaluating the efficacy of plumbing tank vents into combustors to eliminate VOCs. Although this handling of vented gas will eliminate VOC emissions, it will result in a very slight increase in NO_x.
- Operators will evaluate removing idle, unused, or unnecessary equipment after determining what the benefit may be in terms of reduced emissions.
- Operators are evaluating the feasibility of reducing or eliminating NO_x on compressor engines through electrification or replacement of current engines with lower-emissions engines.
- Operators are working with drilling contractors to improve emissions on drill rigs. This process is ongoing. Operators anticipate that all rigs in the area would be Tier II or cleaner by the time of project implementation.

- Necessary air permits to construct, test, and operate facilities will be obtained from the WDEQ-AQD. All internal combustion equipment will be kept in good working order. BACT will be implemented as required by WDEQ-AQD.
- Operators will use either flaring or "green completions" to eliminate venting natural gas, thereby significantly reducing VOC emissions.

7.2 Cultural and Paleontological Resources

- Operators will conduct site-specific surveys or block surveys for cultural resources and paleontological resources, as applicable. Operators will take appropriate action to avoid or mitigate impacts to these resources, if they are identified, in compliance with all applicable rules and regulations.

7.3 Surface Disturbance and Transportation Planning

- Concurrent with the development of the EIS, the Operators will develop a transportation plan to document methodology for minimizing surface disturbance and associated impacts to soils and water, and will submit the plan to the BLM during development of the EIS. The transportation plan will include provisions for rehabilitation of operator-controlled unused and mutually agreed to unnecessary roads, which will be identified during plan development, dust suppression, and traffic reduction.
- The Operators will provide the BLM with a geospatial database of all newly constructed access roads and well pads at least annually. The geospatial database will include the attributes required by Onshore Oil and Gas Order #1.
- The Operators will construct new roads and well sites to standards described in the BLM Gold Book (BLM and USFS, 2007) and in BLM Manual 9113 – Roads.
- The Operators will design and construct all new roads to a safe and appropriate standard, "no higher than necessary" to accommodate their intended use.
- The Operators will surface access roads with gravel or other appropriate material, unless sufficient natural gravel exists, as determined by the AO on a site-specific basis.
- The Operators will provide sufficient tank capacity on the pads of producing wells to minimize collection and transport of produced water to its disposal site.

- Operators will perform interim reclamation of well locations and access roads soon after all sequentially drilled wells were put into production. Reclamation timeframes would comply with Onshore Order #1.

7.4 SOILS AND SEDIMENTATION

- Operators will consider installing surface pipelines where necessary to reduce erosion, on a site-specific basis to be determined at the time of the on-site inspection during permitting.
- Operators will implement best management practices as described in their site-specific Storm Water Pollution Prevention Plans and will consult with the AO during the time of on-site inspection during permitting to determine procedures/construction techniques to prevent bank erosion from construction and use, erosion, and sedimentation.
- Operators will utilize best management practices and materials such as rip rap, where practicable, to prevent erosion and head cutting from culverts and other drainages.
- Operators will employ site-specific measures to prevent sedimentation into the Green River and its tributaries.
- Operators will not construct using frozen or saturated soils or during periods when watershed damage is likely to occur.

7.5 WATER RESOURCES

- Operators will maintain a 500-foot offset to riparian areas and surface water, or, if not viable, will consult with the AO to develop site-specific mitigation if no other practical option exists.
- Operators will avoid new construction within the 100-year floodplain of the Green River. No permanent structures will be constructed within its boundary unless it can be demonstrated on a case-by-case basis that there is no physically practical alternative.
- Operators will line all reserve pits and pad them as necessary to prevent tearing or puncturing of the liner and fluid migration to the subsurface.
- Operators will construct impenetrable containment berms completely around production facilities designed to store fluids (i.e., production tanks, produced water tanks, methanol tanks). The pad floor beneath the tanks would be constructed with a clay layer or with synthetic material to prevent fluid migration to the subsurface.

7.6 VISUAL RESOURCES

- Operators will paint all new facilities a color that best allows the facility to blend with the background, such as Shale Green Munsell Color Code 5Y 4/2, which typically is consistent with a vegetated background, or the color specified by the AO.
- Operators will perform final reclamation recontouring of all disturbed areas, including access roads, to the original contour or a contour that blends with the surrounding topography.

7.7 VEGETATION

- Operators will utilize fencing, as appropriate; to protect reclaimed areas from grazing until revegetation can be established.
- Operators will control weeds on disturbed areas within the exterior limits of the access roads, well pads, and pipeline routes in accordance with approval from the AO.

7.8 LIVESTOCK GRAZING

- Operators will repair or remedy any damage to the function of range improvements (e.g. fence damage, cattle guard cleaning, livestock loss) from operations as soon as possible.
- Operators will continue to conduct operations so as to retain access to cattle movement corridors (trails) so that livestock can be managed.
- All pads will be completely fenced until reclamation is successful. All new fences will adhere to standards provided by BLM Handbook H-1742-1. Fences will be maintained appropriately.

7.9 WILDLIFE AND OTHER

- During drilling and completion, all garbage and non-flammable waste materials will be contained within a self-contained, portable dumpster or trash cage. As needed, the waste will be transported to an approved disposal facility.
- Operators may use remote telemetry to monitor wells throughout the field to reduce truck travel. Telemetry equipment would be used to improve well evaluation and operational efficiency, and to minimize well visits. This measure will reduce the amount of operational traffic in the field during production to minimize the long-term impacts to wildlife.
- Operators will provide sufficient tank capacity on the pads of producing wells to minimize, as feasible, collection and transport of produced water to disposal sites. This measure will reduce the amount of operational traffic in the field during production to minimize the long-term impacts to wildlife.
- Anti-perch devices will be installed on all overhead power lines to reduce perches for predators, thereby minimizing predation of sage-grouse and other wildlife.

8.0 OPERATOR COMMITTED BEST MANAGEMENT PRACTICES

As detailed in this Project Description, the Operators will employ the following Best Management Practices (BMPs) on a site-specific basis on their facilities to reduce, prevent, or avoid adverse environmental impacts. These BMPs were identified in Appendix 5 of the Pinedale FEIS/PRMP (Fluid Mineral Best Management Practices). Many of these BMPs are currently implemented in the Project Area. This list is not all inclusive and may be modified over time as conditions change and new practices are identified. The Operators anticipate that appropriate application of BMPs will be identified by the BLM during the EIS, and subsequent APD, processes.

8.1 BIG GAME CRUCIAL WINTER RANGE AND OTHER WILDLIFE HABITAT

- Horizontal drilling of gas wells.
- Drilling of multiple wells from a single pad.
- Closed drilling systems where the water table or topographic considerations interfere with the reserve pit, to be determined at the time of permitting.
- Flareless or “green” completions where feasible.
- Remote well monitoring throughout the field.
- Transportation planning throughout the field to reduce road density and minimize traffic-related impacts.
- Cluster development will be evaluated on-lease and where winter exceptions are granted.
- Habitat enhancement projects may be identified and implemented.

- Using BLM standard wildlife fences where fencing is installed.

8.2 Sage Grouse Habitat

In addition to the BMPs in Section 8.1, Operators will employ the following:

- Installation of raptor anti-perch devices on all overhead power lines.
- Adhering to stipulations and conditions of approval regarding sage-grouse, unless exceptions granted.

8.3 VRM Class II and III Areas

- Repetition of elements of form, line, color, and texture to blend facilities with the surrounding landscape.
- Painting all new facilities a color that best allows the facility to blend with the background, typically a vegetated background.
- Final reclamation recontouring of all disturbed areas, including access roads, to the original contour or a contour that blends with the surrounding topography.
- Screening of facilities from view if deemed appropriate and necessary.
- Reclamation of all unused well pads within one year.
- Following the contours of the land to reduce unnecessary disturbance.
- Recontour and revegetation of disturbances to blend with the surrounding landscape.
- Reclamation of unused or mutually agreeable unnecessary roads to the original contour.

8.4 Air Quality

- Use water and dust suppressant on roads, as agreed to in a Transportation Plan (to be developed).
- Post speed limits on wellsite access roads, as appropriate.
- Implement transportation planning throughout field.

8.5 Fluid Mineral Construction, Operation, and Reclamation

- Horizontal drilling of gas wells.
- Drilling multiple wells from a single pad.
- Closed drilling systems where the water table or topographic considerations interfere with the reserve pit.
- Remote well monitoring throughout the field.
- Transportation planning throughout the field to reduce road density and minimize traffic-related impacts.
- Design and construction of all new roads to a safe and appropriate standard, “no higher than necessary” to accommodate their intended use.
- Reuse of existing roads and well pads where feasible.
- Interim reclamation of well locations and access roads soon after the well is put into production.
- Storage of chemicals within secondary containment in case of a spill.
- Onsite bioremediation of oil field wastes and spills.
- Removal of trash, junk, waste, and materials not in current use on facilities controlled by the Operators participating in this EIS.

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