2. ALTERNATIVES INCLUDING THE PROPOSED ACTION

2.0 INTRODUCTION

This section describes the alternatives developed to address the issues, and presents a comparison of the alternative features and a summary of the effects that would result from implementing each alternative. Section 2.2 presents these alternatives in detail.

2.1 DEVELOPMENT OF ALTERNATIVES

Alternatives present different management options in response to the purpose and need for the Proposed Action and address the relevant issues related to the Proposed Action. The development of alternatives to the Proposed Action is critical to the complete and thorough implementation of NEPA and its accompanying regulations. In accordance with 40 CFR 1502.14(a), the BLM is required to sharply define issues and evaluate all reasonable alternatives. The Proposed Action calls for developing oil and natural gas reserves from federal lands within the BNGPA. There are numerous methods by which this goal could be reached, although not all methods are technically or economically feasible. Alternatives to the Proposed Action were based on input from the Operators, the BLM, and the public.

The effects analysis (Section 4) describes the known or potential effects that would result if the alternatives were implemented.

Alternative A is the No Federal Action Alternative. The private and state wells and associated infrastructure would be developed in the project area. The BLM would not approve the federal wells or associated infrastructure. This alternative limits natural gas production and development to private and state land and minerals only, in order to reduce the overall potential impacts to water, wildlife, and cultural resources.

Alternative B is the Proposed Action with Additional Mitigation. The Operators' proposed project would be approved for the private, state, and federal wells and construction of the associated infrastructure. Mitigating measures that are not already part of the Operators' proposal have been included as part of this alternative. This alternative was developed to analyze full implementation of the Operators' proposal, while incorporating mitigating measures identified during project review that would avoid or reduce impacts to area cultural and natural resources.

Alternative C is the Maximum Development Alternative. This alternative was developed to assess effects of more development than either A or B.

2.1.1 Alternatives Considered but Eliminated from Detailed Analysis

Several additional alternatives were considered, but were not further evaluated for reasons described below.

Directional/Horizontal Drilling

Directional/horizontal drilling can only be considered a viable alternative if the method and geological environment meet the several technical and economic requirements to overcome the challenges of applying this technique to Upper Cretaceous formations within the BNGPA. The limitations of directional drilling are primarily dependent on maximum hole angle, rate of angle change, and friction considerations. The critical components to be considered in determining whether a well can successfully be drilled and completed as a directional well are:

- depth of well to the potentially productive zone;
- type of anticipated product (oil, gas, condensate, or combination) in combination with reservoir pressures and the applicability of directional/horizontal drilling to each respective formation;
- reservoir/formation characteristics (formations suitable for directional/horizontal well completions); and
- multiple-zone completions.

It is apparent that not all fractured reservoirs benefit economically by the application of this technology.

The downhole assembly/stimulation needed to produce the well can limit the use of directional/horizontal drilling. The Operators need to assess the presence of a number of critical reservoir, operational, and well design parameters. The two most critical reservoir performance parameters are the reservoir thickness and vertical-to-horizontal permeability ratio.

The oil and gas resources of the Bowdoin Dome have been known since before World War I. Natural gas was discovered in 1913 with production beginning the same year. Natural gas production was very limited until 1929, and by the end of 1930, there were approximately 25 producing natural gas wells that serviced Glasgow and Malta. As discussed on page 3-43 and reflected in Table 3.8-2, natural gas production in the BNGPA has been taking place for several decades. Production on this structure is chiefly from relatively shallow (less than 3,000 feet) reservoirs in the Upper Cretaceous Carlile Shale, Mowry and Greenhorn Formations, and Belle Fourche Shale, and is from a combination of stratigraphic and structural traps. In the BNGPA, production from the Carlile Shale comes from the Bowdoin Sandstone, a facies equivalent of the shale that reaches about 300 feet in thickness near the town of Mosby. The Greenhorn Formation is about 250 feet thick in the Bowdoin Dome area, where it is a principal gas-producing unit. The Mosby Sandstone Member of the Belle Fourche Shale is known as the Phillips Sandstone on Bowdoin Dome, where it is a major gas-producing unit.

Directional and horizontal drilling was also eliminated from detailed analysis due to the technical viability of drilling such a well. The formations within the BNGPA are stack reservoirs that are completed within the same well bore. The BNGPA has up to five zones of interest. A vertical well is the only economic way to commingle and produce these five zones in one well bore. In most cases directional/horizontal wells are significantly longer than conventional vertical wells are deep. This is required so the drainage points of the reservoir are evenly distributed to maximize resource recovery. Longer wells do create a problem as more reservoir energy is required to move the gas through the longer pipe to the surface. In most (if not all) Rockies reservoirs, the reservoir energy is depleted as the resource is recovered. Based on these principles, a shallower vertical well would flow longer than a directional/horizontal well, given the same reservoir energy. For most energy depletion reservoirs, vertical wells that are spread optimally in the reservoirs will effectively recover more natural gas reserves.

During the last three years directional drilling techniques have been utilized in approximately one-third of the wells in the nearby Bear Paw South Field to facilitate resource recovery in areas with significant faulting and/or topographic challenges. These wells are relatively shallow with measured depths of 2,500–3,000 feet and true vertical depths around 2,000 feet. Typically the well bore deviation does not exceed 45 degrees due to operational concerns and the bottom-hole location has a reach of 500–1,000 feet from the surface location.

Directional drilling is not practical in the BNGPA for the same reasons as horizontal drilling. As an example, a BNGPA well at 2,000 feet requires a 200-foot surface conductor casing. If drilling to a 160-acre location from the center of a 160-acre location, a horizontal displacement of 933 feet must be achieved. The necessity of starting the curve of the horizontal displacement below the casing shoe of the conductor pipe would require the well bore inclination to be greater than 45 degrees from vertical, which brings the problem of artificial lift placement into question again.

Central Pad Multi-Well

The alternative of directionally drilling several wells from one central location was also considered. In addition to the limitations already discussed above, this central multi-well location requires a much larger footprint that is equal to or larger than four single-well pads. The access road to a multi-well pad facility must be upgraded to handle three times the normal traffic of a single-well pad. Consideration must also be given to the fact that the drilling rig would be in operation three times longer than for a single well.

Maximization of resource recovery is a significant consideration. The optimum method of recovering reserves is an important factor in selecting the appropriate methodology for unique reservoir conditions, as well as for minimizing the reserves left behind.

The formations within the BNGPA are stack reservoirs that are completed within the same well bore. The BNGPA has up to five zones of interest. A vertical well is the only economic way to commingle and produce these five zones in one well bore.

The wells in the BNGPA are not deep enough to share a single pad for multiple wells. It is not possible to achieve a high enough angle to reach the reservoir’s optimum depletion spacing.

Produced-water Disposal and Treatment Options

Discussed below are the various water-disposal scenarios that were considered for the Bowdoin Natural Gas Project. These water-handling alternatives were considered but were not analyzed in detail for this EA. Typically, the amount of produced water within the BNGPA averages less than five barrels/day/well (BWPD). Wells converted to artificial lift may produce up to 15 BWPD. This relatively small amount of produced water would not necessitate the installation of a gathering system to collect the produced water from each location for transportation to one or more centrally located treatment and disposal facilities. The cumulative economic and environmental effect of the installation of produced-water gathering and treatment facilities makes the concept unfeasible. All practical water-disposal methodologies were considered but are not being proposed as the primary method of handling produced water at this time. The considered methodologies include re-injection, treatment and surface discharge, surface discharge without treatment, and land application. In the future, the increased use of artificial lift production systems in the field may significantly increase the volume of water produced and necessitate the evaluation of produced-water management alternatives including a gathering system to replace truck transportation to centralized facilities designed to manage water from numerous wells producing greater than five BWPD.

Re-injection: This method of produced-water management is not viable because of the environmental disturbance as described above. In addition, geological conditions within the BNGPA do not offer any known zones capable of taking produced water for a period of time sufficient to support the cost of installation of the required re-injection infrastructure.

Conventional Surface Discharge of Untreated Water: This method of disposal would not be widely permitted in the BNGPA due to naturally occurring salinity in the produced water. While a few natural gas wells within the area would meet the 'freshwater discharge' criteria, most would not.

Land Application: In this disposal method, treated (and in some cases, untreated) water is disposed of on the land surface and consumed by evapotranspiration. Typically, the water is applied using spray irrigation equipment (i.e., center pivot or side-roll systems). This method of disposal must be curtailed during winter months and as a consequence, storage is required during the winter. Land application is limited by the presence of well-drained, low-clay-content soils which are less susceptible to reduction in infiltrative capacity through the application of produced water. Use of this method of disposal is limited, and additional review and studies of land application would be considered by the respective agencies before issuing these types of irrigation permits.

Treatment: Salinity and sodium absorption ratio (SAR) have been identified as the primary concerns in natural-gas-produced water. These parameters are related to irrigation. Existing treatment technologies such as reverse osmosis and ion exchange have been tested to condition natural-gas-produced water to make it suitable for irrigation.

In the reverse osmosis (RO) procedure, the natural-gas-produced water is forced through a semi-permeable membrane using a high-pressure pump. The term 'osmosis' refers to the natural tendency for a solvent (in this case, water) to move through a membrane from a solution with a low solute (salt) concentration to a solution with a high solute concentration. By applying pressure to the concentrated side of the membrane, it is possible to reverse this phenomenon and force the water from a higher salt solution to a lower salt solution; hence, reverse osmosis.

In a typical application, RO may remove 95 percent or more of the salts from the raw water. This high salt-removal rate is attractive for a water supply system, where the total dissolved solids (TDS) of the treated water should be well below 500 parts per million (ppm). For BNGPA-produced water, however, 95 percent salt removal is excessive and cost-prohibitive at this time. This water would be so pure that it would rapidly accumulate salts if discharged to the ground surface. Typically, treated water is mixed with raw water to produce an effluent that is comparable to native surface waters. RO results in a brine stream of 20 to 50 percent of the volume of the influent stream, depending upon the efficiency of the RO filter. The RO brine stream would likely be disposed of in an approved injection well. Currently, there is neither an approved injection well nor a geologic formation capable of being approved for injection within the BNGPA or within its proximity. Again, low volumes of water produced in the BNGPA do not warrant a sophisticated disposal system that would also be cost-prohibitive.

In ion-exchange treatment, natural-gas-produced water is passed over a resin bed that exchanges positively charged ions in the raw water for hydrogen ions. The resulting high concentration of hydrogen ions creates a low pH (i.e., acidic) effluent that is buffered to a neutral pH with calcium carbonate. The ion-exchange process typically reduces both TDS and SAR. The process results in a brine stream that, depending upon the efficiency of the ion-exchange process, can be as little as one percent of the influent stream. The brine stream must be disposed of in an approved injection well.

2.2 DESCRIPTION OF THE ALTERNATIVES

A comparison of the major components for the three alternatives is found in Table 2.3-1. A detailed description of each alternative follows.

2.2.1 Alternative A—No Federal Action

The No Federal Action Alternative is required under the President's Council on Environmental Quality (CEQ), 40 CFR 1502.14(d), and applicable BLM implementing regulations. The No Action Alternative provides a benchmark, enabling decision-makers to compare the magnitude of environmental effects of the action alternatives. Under the No Action Alternative, the BLM would reject the Operators' proposal to develop natural gas in the BNGPA as described in the Proposed Action. Rejection of the Operators' proposal would not be a rejection of all oil and gas development activities in the area, as the BLM would not have approval authority on fee and state wells except in the case of reverse split-estate lands (federal surface and fee or state minerals).

The analysis of the No Federal Action Alternative includes the development and production of wells and infrastructure associated with the proposed fee and state wells (558 private and 62 state) in the BNGPA. No approval would be issued by BLM under this alternative for the wells and facilities associated with federal leases. Figure 1.1-1 shows the project boundary and land-ownership for the BNGPA. Figure 2.2-1 shows the existing oil and gas infrastructure in the BNGPA.

The No Federal Action Alternative includes these elements: the MBOGC would approve the drilling, completion, and production of 558 private wells and 62 state wells; construction of associated infrastructure of access roads, flowlines, and power lines (approved on a site-specific basis as needed for electricity to produce the natural gas); reclamation of disturbed areas; existing water management options; and the use of meter and compressor facilities. These 620 wells would be drilled and completed in the Upper Cretaceous including, but not limited to the Niobrara, Bowdoin (Carlile), Greenhorn, Phillips, Belle Fourche, and Mowry Formations (a/k/a Colorado Group). Of the 620, 220 would be replacement wells at a legal location within the applicable 160-acre spacing unit. The average life of the project is expected to be 30 to 50 years with final reclamation to be as specified in **Appendix D—Reclamation Plan**. Components of the proposed project are listed in Section 2, Table 2.3-1.

2.2.2 Alternative B—Proposed Action with Additional Mitigation

The Operators' proposed BNGPA development is the Proposed Action alternative. The plan describes the project and Best Management Practices (BMPs) designed to implement the project. The analysis of Alternative B includes the development and production of wells and infrastructure associated with the proposed federal, private and state wells (635 federal, 558 private, and 62 state; see Table 2.3-1) in the BNGPA.

The Proposed Action includes the drilling, completion, and production of 635 federal, 558 private, and 62 state wells; construction of associated infrastructure of access roads, flowlines, and power lines (approved on a site-specific basis as needed for electricity to produce the natural gas); reclamation of disturbed areas; existing water management options; and the use of meter and compressor facilities. These 1,255 wells would be drilled and completed in the Upper Cretaceous including, but not limited to the Niobrara, Bowdoin (Carlile), Greenhorn, Phillips, Belle Fourche, and Mowry Formations (a/k/a Colorado Group). Of this total, 435 wells (215 federal, 22 state, and 198 private) would be replacement wells at a legal location within the applicable 160-acre spacing unit. The life of the project is expected to be 30 to 50 years, with final reclamation to be as specified in **Appendix D—Reclamation Plan**. Components of the proposed project are listed in Table 2.3-1.

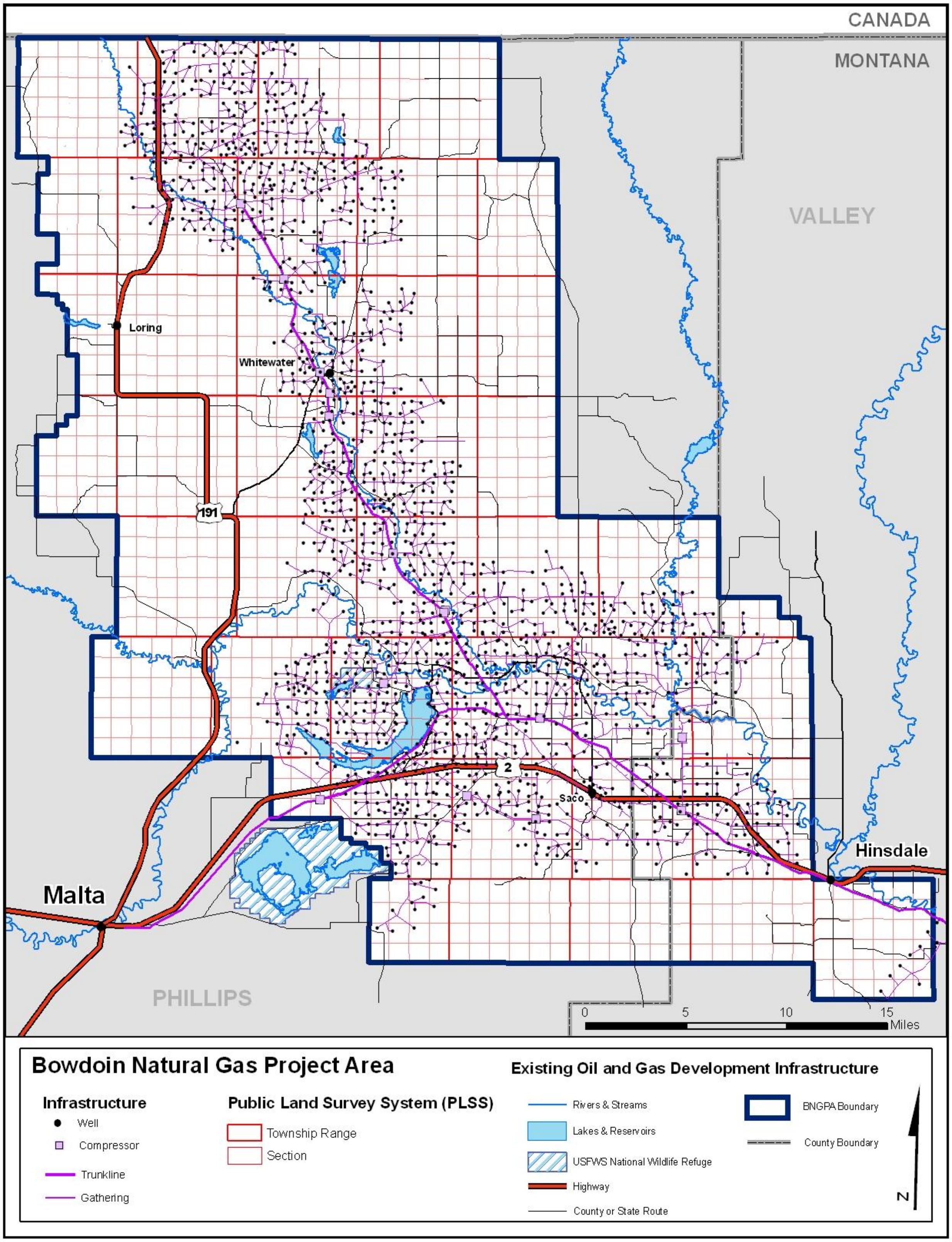
2.2.3 Alternative C—Maximum Development Alternative

A maximum development alternative has also been analyzed. The plan describes the project and BMPs designed to implement the project. The analysis of Alternative C includes the development and production of wells and infrastructure associated with the proposed federal, private, and state wells (964 federal, 847 private, and 94 state; see Table 2.3-1) in the BNGPA.

Alternative C includes the drilling, completion, and production of 964 federal, 847 private, and 94 state wells; construction of associated infrastructure including access roads, flowlines, and power lines (approved on a site-specific basis as needed for electricity to produce the natural gas); reclamation of disturbed areas; existing water-management options; and the use of meter and compressor facilities. These 1,905 wells would be drilled and completed in the Upper Cretaceous including, but not limited to the Niobrara, Bowdoin (Carlile), Greenhorn, Phillips, Belle Fourche, and Mowry Formations (a/k/a Colorado Group). Of this total, 660 wells (326 federal, 33 state, and 301 private) would be replacement wells at a legal location within the applicable 160-acre spacing unit.

The average life of the project is expected to be 30 to 50 years, with final reclamation to be as specified in **Appendix D—Reclamation Plan**. Components of the proposed project are listed in Table 2.3-1.

Figure 2.2-1. Existing Oil and Gas Infrastructure in the BNGPA



2.2.4 Project Description Common to all Alternatives

The following description of the project applies to all three alternatives.

Preconstruction

Development activities would be approved prior to initiation of construction through applicable permitting procedures including filing with BLM the appropriate right-of-way application with an applicable map.

The Operators would file all appropriate permit applications with the MBOGC. As more is learned about the gas resources in the BNGPA, MBOGC-specific spacing orders for the area could change and further development could be proposed.

Road Construction/Access

The Operators would use existing crowned and ditched roads within the BNGPA to the extent practicable, and construct new roads only where necessary to gain access to specific drill sites. Access road mileage and disturbance acres for the three alternatives would be as follows:

- **Alternative A.** Access would primarily use approximately 207.5 miles of existing and proposed two-track roads. The resulting surface disturbance would be 301.8 acres.
- **Alternative B.** Access would primarily use approximately 418.75 miles of existing and proposed two-track roads. The resulting surface disturbance would be 609.1 acres.
- **Alternative C.** Access would primarily use roughly 636 miles of existing and proposed two-track roads. The resulting surface disturbance would be 925.1 acres.

Surface Ownership of the project area is approximately 33 percent federal, 61 percent private, and 6 percent State of Montana. Access road mileage and surface disturbance shown above would be proportional to surface ownership.

Pipeline corridors would also be used as temporary roads for access to well sites when feasible. Culverts and/or low-water crossings would be installed at drainage crossings, if needed. Gravel needed for surfacing material would come from a pit permitted by MDEQ.

The road and pipeline routes are proposed as agreed to by the appropriate private-surface owner or state agency. Where possible, whether proposed two-track road or existing, the roads would serve as a common corridor for gas and electric lines. The project map (Figure 1.1-1) shows the project boundary, existing and proposed wells, access roads, pipelines, power lines, and the central gathering/metering/water-processing facilities in the project area. The location of roads and pipelines would be determined in the APD for each individual well. The Operators would construct any required access roads on federal surface in accordance with standards presented in BLM Manual Section 9113 (1985, 1991).

Well Pad

The Operators propose to utilize a traditional well pad design used in north-central Montana. Single-well pads would be approximately one acre in size. The actual disturbance for the drilling rig being utilized by the Operators in the area is 120 by 190 feet in size (approximately 0.52 acres). All available vegetation and topsoil would be salvaged and stockpiled for future reclamation operations. Erosion-control BMPs would be utilized on well pads to control sediment movement off of the site. If less than six inches of topsoil are available, topsoil along with an appropriate quantity of other suitable spoil (with BLM approval) would be salvaged so that a minimum of six inches of plant-growth material would be available for use during revegetation operations. Topsoil and suitable subsoil piles would be constructed so as to minimize erosion to local drainage channels. Appropriate signs would be placed on all topsoil and suitable subsoil stockpiles. Soil that is not re-spread within 30 days would be covered with a tackifier, mulch, or other approved cover.

Well pads would be constructed and leveled using standard cut-and-fill construction techniques (see section **2.2.5**, **Applicant-Committed Mitigation**). Components of the well pad include a reserve pit and an emergency pit for emergency and development flaring. At each drilling location, drilling wastes including cuttings, water, and drilling muds would be placed into a reserve pit. Each pit would be approximately 12 feet wide by 60 feet long by 4 feet deep (for 1,000- to 1,500-foot total depth [TD] wells) or 6 feet deep (for 1,500- to 2,000-foot TD wells) and enclosed with a wire fence and/or fencing panels to keep out livestock and wildlife. After conclusion of drilling operations, fluids in the pits would be removed and either used for other drilling operations or disposed of properly. The pits would be backfilled after the remaining muds have dried. Wastes accumulated during drilling and completion operations would be contained on the well site and disposed at the Saco sanitary landfill. Toilet facilities would be provided for field operations. The locations would not be graveled, but left in a natural state. These locations would also be used during completion operations and then reclaimed to a smaller size, which is dependent upon the area needed for the produced-water evaporation pit. If warranted, the reserve pit would be lined with a 12-mil reinforced poly-liner to temporarily contain drilling fluids, cuttings, and produced water. The poly-liner would be impermeable (i.e., having a permeability of less than 10^{-7} m/sec) and chemically compatible with all substances that might be placed in the pit. Venting of any gas produced would be over an unlined emergency pit. All pits would be constructed in accordance with MBOGC requirements. Any drilling operations that require the use of exotic non-natural muds (e.g. oil-based mud, mineral oil, etc.) will require a closed-loop system in which the drilling mud will be completely contained. The preferred method of accomplishing this is to utilize steel tanks that adequately contain the mud.

Drilling

Each well drilled would require the transportation of approximately five truckloads of drilling-related equipment and materials. This would include the drill rig, drill pipe, drilling fluid products, and related support equipment. Additional vehicle traffic would also be required for the transportation of personnel and expendable supplies such as fuel, drilling fluid additives, water, etc. The specific amount of vehicle traffic would vary, depending on the progress of drilling operations, but would likely not exceed a total of 6–7 vehicle trips/day including rig transport over a two-day period for each drill site during drilling operations. Drilling depths would vary within the project area; however, wells would typically be 1,500-3,000 feet deep. Drilling each well would require 5,000 barrels (bbls) (210,000 gallons; 0.64 acre-feet) of water. Generally, water used for drilling would be purchased from an existing commercial water source. Drilling a gas well would typically take two days.

Wells would be drilled by conventional gas well-drilling rigs. After about three weeks of no activity, cased-hole logs would be run on the well, which would be completed in one day. The following casing program would be followed:

Surface Casing—Generally, a minimum of 100 feet (or 10 percent of the projected total depth of the well, whichever is greater) of 7-inch, 17 #/ft API-graded H-40 casing would be set. New limited-service pipe may be used for the surface casing, but would require prior approval by

BLM before being installed in a federal well. The surface casing would be set utilizing a minimum of 65 sacks of Class 'G' cement with reasonable necessary additives (this allows for 70 percent excess over the calculated annular volume). The surface casing would be cemented back to surface either during the primary cement job or by remedial cementing. Five bbls of fresh-water flush would be used ahead of cement when cementing surface casing. At a minimum, a top wiper plug would be used while displacing cement into place and would be displaced no closer than 30 feet from above the shoe. Surface casing would have a centralizer on each of the bottom three joints.

Production Casing—At a minimum, production casing would be consistent with 4½-inch, 9.5#/ft, J-55 casing. The production casing would be set utilizing a minimum of 11.5 sacks of class 'G' cement per 100 feet of hole, with reasonable necessary additives (this allows for 25 percent excess over the calculated annular volume at a cement yield of 1.15 cubic feet/sack). Higher-yield cement (i.e., 50-50 Poz) is allowed under this plan provided the cement would reach a compressive strength of 1,500 psi.

Cementing of production casing is not required; however, when this technique is utilized, the production casing would be cemented back to surface either by primary cementing or by remedial cementing. A best attempt would be made to assure that all productive intervals are isolated with good cement coverage around the pipe. This would be accomplished by placing centralizers at 100 feet above and below the productive interval and placing the centralizer every 100 feet between the top and bottom centralizer. Ten bbls of fresh-water flush would be used ahead of cement when cementing production casing.

Each well is typically drilled to approximately 400 feet deeper than the top of the Phillips/ Greenhorn formation or to the base of the Mowry formation. Production casing would then be run and the selected productive intervals would be jet perforated. Fresh water would be used in the drilling operations. All wells capable of commercial production would be completed and produced and the associated infrastructure would be constructed and installed.

Once the well is drilled and completed, normal traffic on the access road would include pumper vehicles and occasionally a water truck to remove production water from the well's evaporation pit.

Alternative A: 558 private wells would be drilled on 558 well sites and 62 state wells would be drilled on 62 well sites (see Table 2.3-1) with one well drilled on each well site at 160-acre site spacing (four wells per 640 acres). Anticipated depth of the wells would be from approximately 1,000 to 3,000 feet TD. The drilling period is anticipated to last 10–15 years.

Alternative B: 635 federal wells would be drilled on 635 well sites, 558 private wells would be drilled on 558 well sites and 62 state wells would be drilled on 62 well sites (see Table 2.3-1) with one well drilled on each well site at 160-acre site spacing (four wells per 640 acres). Anticipated depth of the wells would be from approximately 1,000 to 3,000 feet deep. The drilling period is anticipated to last approximately 10–15 years.

Alternative C: 964 federal wells would be drilled on 964 well sites, 847 private wells would be drilled on 847 well sites, and 94 state wells would be drilled on 94 well sites (see Table 2.3-1) with one well drilled on each well site at 160-acre site spacing (four wells per 640 acres). Anticipated depth of the wells would be from approximately 1,050 to 2,450 feet deep. The drilling period is anticipated to last approximately 10–15 years.

Completion, Testing, and Production

When necessary, well completion isolates aquifers with cemented surface and production casing to prevent mixing fluids between formations and to isolate production zones. The well is perforated using jet powder charges that burn designed holes through the casing and cement into the production zones, creating a path for fluid travel into the well bore. If the production zone or formation does not allow enough flow into the well bore for economic production, this zone is called 'tight.' A decision may be made to stimulate the production zone. Wells in the Bowdoin area are stimulated utilizing the fracturing technique. Fracturing is done by pumping fluid into the well bore with enough pressure to crack (fracture, or 'frac') the rock. Once this fracture is initiated, sand is added to the frac fluid and pumped into the fracture, which holds (props) the fracture open. The frac fluid is able to transport the sand because it includes a guar polymer-based viscosifier. The system used most frequently in the Bowdoin Dome is a simple fresh-water base with a polymer viscosifier, which is called a slick water or linear gel system. Once the fracture is completed the well is opened up through a choke and allowed to flow back the fracturing fluid into the reserve pit. Because of low reservoir pressures, nitrogen is added to the frac fluid, which creates foam to help energize the formation and aids in flow-back of the fluids and avoidance of a water block. This improves the ability to recover more of the frac fluid from the formation more quickly.

Once the well is drilled, completion operations would occur over a number of weeks. The completion time would be dependent on the number of zones being completed. Bowdoin-area wells are typically completed in one to five zones. It typically requires 11 days to complete one zone, although well site activity only occurs for four days out of the 11 and, in many cases, only for a matter of hours during those active days. Completion travel consists of 12 semi-truck-sized loads traveling three days out of 11 and a smaller number of trucks traveling two days for each production zone being completed.

During field operations, each well is visited at least once and sometimes twice each week by a fieldman or pumper to ensure the evaporation pits are not overflowing, there are no gas leaks, and the site is secure. Each fieldman typically visits 10–12 wells per day.

Pipeline Construction and Production

If testing indicates that a well would be commercially viable, flowlines and gathering lines would be installed. Where required, product lines would be connected with pumps/compressors that would be located within the BNGPA. Gas produced as a result of the proposed project would be transported by buried gathering lines and pipelines that would be installed adjacent to existing common corridors (e.g., roads, pipelines, and gathering lines) whenever practicable. Proposed flowlines (pipelines) to be installed would be 3.0-inch outside diameter (OD) plastic, 3- and 4-inch inside diameter (ID) steel. Plastic lines would be plowed to a minimum depth of 38" and all steel lines would be trenched to a depth of 42 inches. The typical right-of-way would be 50 feet in width and actual disturbed area during construction would be 25 feet in width for steel lines and approximately 5 feet for plowed plastic lines. Gathering companies are not required to perform hydrostatic testing; however, hydrostatic testing using water, gas, or air may be performed. In addition, leak testing may be performed by filling a pipe with gas or air and monitoring the pressure, typically for a period of 4–8 hours. Radiographic inspection of approximately 33 percent of welded steel lines would also be performed. Steel lines would be externally coated with fusion-bonded epoxy for corrosion protection. Line locations would be marked on the ground surface to prevent third-party damage.

Approximate surface disturbances due to flowline construction are shown by alternative in Tables 2.2-1 through 2.2-3. Note that these are short-term disturbances, which would be completely reclaimed after construction.

Table 2.2-1. Surface Disturbances due to Flowlines for Alternative A

Flowline Type	Length (miles)	Width (feet)	Disturbed Acres
Plowed	103.75	5	62.9
Ditched	103.75	25	314.4
Total			377.3

Table 2.2-2. Surface Disturbances due to Flowlines for Alternative B

Flowline Type	Length (miles)	Width (feet)	Disturbed Acres
Plowed	210	5	126.9
Ditched	210	25	634.8
Total			761.7

Table 2.2-3. Surface Disturbances due to Flowlines for Alternative C

Flowline Type	Length (miles)	Width (feet)	Disturbed Acres
Plowed	318	5	192.7
Ditched	318	25	963.6
Total			1,156.3

Surface ownership of the project area is 33 percent federal, 61 percent private, and 6 percent State of Montana. Flowline surface disturbance for each alternative would be proportional to surface ownership.

Once the flowlines (plastic and steel) are installed, rights-of-way would be backfilled and reseeded with a BLM-approved mixture or a different mixture if requested by the affected surface owner(s). The reclaimed rights-of-way would be monitored until vegetation is re-established. Erosion control would be installed where necessary. The gathering companies would utilize BMPs, such as straw-bale barriers and filter-fabric fence, as required to control erosion prior to the re-establishment of vegetation on disturbed surfaces. BLM-approved gates or cattleguards would be installed where needed for access. Flowlines crossing gravel roads would be installed in an open cut that would be backfilled; flowlines crossing highways would be installed by boring underneath the pavement. Irrigation canals would be open-cut when feasible or bored or flumed if not (dictated by Bureau of Reclamation). All steel lines would be cathodically protected.

Production and maintenance operations would occur on a year-round basis and would last for the LOP (30–50 years). Access roads to productive well sites would be maintained by the Operators to BLM standards, and would allow year-round access. Access roads would be inspected periodically by the Operators to minimize resource damage and ensure safe operating conditions. Production and maintenance operations would be conducted in accordance with industry standards for safety and efficiency.

Surface facilities at each producing well would consist of a wellhouse and possibly an artificial lift device (approximately 12 feet by 6 feet, 10 feet tall) enclosed in three-rail welded fence panels. The wellhouse would be painted a color to blend with the surrounding area. Approximately 70 percent of the new locations would have a 40-foot square evaporation pit, and 30 percent of the locations would have a 60-foot square evaporation pit. The area within the fence would be graveled while the area outside the fence would be reclaimed after installation of production equipment. The existing field compressor sites would be utilized by this proposal.

Abandonment and Reclamation

All wells would be plugged in accordance with MBOGC or BLM (as applicable) rules and regulations. Site abandonment would include the removal and salvage of all above-ground facilities in accordance with the Sundry Notice, including production facilities and equipment, tanks, meters, etc. The BLM requires that drilling pits be pumped dry and either fenced or backfilled immediately upon well completion. The location of mud disposal for each well must be disclosed in the APD. If a liner has been used in the reserve pit, any liner material must be removed to below ground level before being covered (BLM 1989). BLM rules require earthwork for interim and final reclamation to be completed within six months of well completion or well plugging (weather permitting). Upon specific approval, reserve pit fluids could be allowed to dry by evaporation for approximately one year prior to reserve pit closure and drill site reclamation. When the pit is backfilled, cuttings and drilling muds would be covered to a depth of at least three feet. Produced-water evaporation pits would be handled similarly to reserve pits: fluids would be allowed to evaporate followed by any residual solids being buried under at least three feet of fill material. If drilling or production fluids remain in the pit after one year, alternate methods of drying, removal of the fluids, or other treatment measures would be implemented by the Operators in consultation with the BLM or MBOGC. Necessary permits would be acquired by the Operators if fluids were transported off-site for disposal.

Buried pipelines would be purged of combustible materials and abandoned in place. Following site abandonment, all well sites and roads would be abandoned and reclaimed unless they were determined to be left in place by the authorizing agency or private land-owner.

Reclamation operations would be conducted on all disturbed lands in accordance with MBOGC requirements and surface owner agreements. The short-term goal of reclamation would be to stabilize disturbed areas as rapidly as possible, whereas the long-term goal would be to return the land to conditions approximately equal to those that existed prior to disturbance. Reclamation would occur during two phases: interim and final. If production facilities were installed, reclamation of all disturbed areas not required for production operations would be initiated. Reclamation of all disturbed surface areas along pipeline rights-of-way would also be initiated as soon as practicable (see **Appendix D—Reclamation Plan** for complete details).

Interim reclamation would occur on areas that would be re-disturbed prior to final project abandonment (e.g., topsoil and suitable subsoil stockpiles). For well pad cut-and-fill slopes on producing wells, Operators may, after consulting with MBOGC, BLM, or surface owner (as applicable), elect to conduct either temporary or permanent reclamation. However, Operators would not use temporary reclamation as a means to delay permanent reclamation on areas that would not be re-disturbed.

Interim reclamation would include regrading and recontouring slopes to a 3:1 ratio or less. Regraded surfaces would be ripped between two and four inches below the bottom of a compacted layer, if necessary, to reduce soil compaction. Interim reclamation areas would then be seeded using a certified weed-free seed mix agreed upon with the surface owner, or specified by BLM.

Unused areas around well pads, unused pits, flowlines, pipelines, power lines to wells, cut-and-fill slopes of roads, and any other surfaces not required for field use would be graded to form stable, rounded slopes that blend with the natural terrain. Erosion-control structures and/or sediment containment systems would be built or installed as needed, areas would be ripped, and temporary seeding would be completed. Seeding would occur within three months of completing construction or during the next seeding window, whichever occurs first. Appropriate measures, chemical, biological or mechanical, would be followed to prevent the spread of weed infestations and to reduce potential for spreading weed seed via equipment use.

Upon completion of all production operations, final reclamation of LOP disturbance would be initiated. Reclamation operations would generally include: (1) complete cleanup of the disturbed areas (drill sites, access roads, etc.); (2) restoration of the disturbed areas to the approximate ground contour that existed prior to construction; (3) ripping of compacted areas; (4) replacement of topsoil over all disturbed areas; (5) seeding of reclaimed areas with a certified weed-free seed mixture agreed upon with the surface owner; and (6) fertilizing, if considered necessary. Reclamation measures for each disturbed area would be derived from consultation with the surface owner, and would be specific to each site and the conditions at that site. Interim and final reclamation would occur during the first seasonal opportunity (i.e., after October 15 until the soil is frozen, and before May 15). Reclamation activities would not be conducted using frozen soil material. Spring seeding would be conducted only if fall seeding is not feasible.

Power Sources

The Operators anticipate the need for external power sources to support the BNGPA. These power sources include the use of solar, wind, natural-gas engines, and electrical lines. If and when additional power lines are needed for electricity necessary to produce the natural gas, the respective Operator would make a site-specific proposal. The proposal would address site-specific issues including, but not limited to topography, land-owner and regulatory desires, and cultural and wildlife resources. The Operator would employ BMPs to minimize impacts associated with the proposal.

Electronic Measurement

The Operators propose installing remote electronic measurement at new well locations in the BNGPA where economic and technical conditions warrant the use of such equipment. Electronic measurement allows the Operator’s field personnel to remotely monitor the gas production from each well for temperature, pressure, and well flow. Therefore, the remote electronic measurement reduces field trips by the Operator’s field personnel. The remote electronic measurement would be powered by a solar panel/battery recharge system.

Produced Water

Each producing well site would have a produced-water evaporation pit constructed. Approximately 70 percent of the new locations would have a 40 foot x 40 foot evaporation pit, and 30 percent of the locations would have a 60 foot x 60 foot evaporation pit. All pits would be about 5 feet in depth. The size and number of evaporation pits is not anticipated to increase with artificial lift, although water-hauling to centralized facilities would increase. Approximately 25 percent of the evaporation pits may require periodic water-hauling because of fluctuations in water production. In these cases, the water would be hauled to a permitted disposal site. One operator trucks excess water to a 182,000 bbl facility located in the NW¼SW¼ of Section 7 T36N, R31E in Phillips County, while another makes approximately two trips per day to a 32,000 bbl central water pit located in the SE¼NE¼ of Section 7, T32N, R33E in Phillips County, Montana. Accumulated solids (if any) would be transported to an approved disposal site. Other Operators have, or may also construct, similar permitted, centralized produced-water disposal facilities.

Artificial Lift

The Operators would install artificial lift (AL) systems at new and existing well locations where required by reservoir and wellbore conditions. Artificial lift is utilized to remove formation water from the wellbore to enhance gas production, and ultimate gas recovery, while minimizing additional impact on the field's environment. If AL is not utilized, ultimately available natural gas will decrease and certain wells will be prematurely abandoned. Examples of AL include, but are not limited to, progressive cavity (PC) pumps or reciprocating rod pumps or pumpjacks (PJ). Pumpjacks and PC pumps are currently being used in the BNGPA.

Anticipated location of installations

In most natural gas reservoirs, particularly 'high-quality' reservoirs such as Gulf Coast sandstones, the structural position of the wells is the primary controlling factor with respect to water production. Wells located lower on the structure (down-dip) are generally the first to produce water and require AL for continued gas production. While structural position is undoubtedly one of the factors in controlling water production in the BNGPA, the nature of the reservoirs makes the issue more complex. Unlike high-quality reservoirs, wells in the BNGPA located higher on the structure can yield higher water production than wells located lower on the structure. At least one causative factor is the productive reservoirs in the BNGPA, which are generally considered to be 'shaley sands.' The reservoirs contain high percentages of clays (generally illite / smectite and illite / mica mixes) that reduce both effective porosity and permeability. Further, these clays allow the reservoir rocks to hold more water than would otherwise be possible.

While understanding what controls water production in the BNGPA from a geologic standpoint is difficult, the petroleum engineering aspects of the problem are fairly straightforward: As gas production naturally declines over time through reservoir depletion, the 'critical velocity' needed to lift water from the wellbore is no longer attainable. Hence, water builds up in the wellbore and either inhibits gas production or causes the well to quit producing altogether. This problem is commonly known as 'liquid loading.' Artificial lift is a means of mechanically removing the water from the wellbore to alleviate this problem.

Until recently, operators in the BNGPA had very little need for AL. However, two operators have now installed AL on approximately 39 federal wells and numerous fee-surface wells within the BNGPA. These installations have demonstrated that AL is now necessary in portions of the BNGPA and can be successfully employed to optimize gas production and reserves.

Based on the Operators' current and anticipated future needs, the following tables summarize AL installations by operator and in total.

Table 2.2-4. Artificial Lifts, All Operators

Year	Operator	Total AL (PC or PJ)	AL on Federal Surface	AL on Other Surface
1	All operators	115	72	43
2	All operators	105	63	42
3	All operators	135	72	58
Life of Field (Total AL operating at a time)	All operators	990	375	315

Table 2.2-5. Artificial Lifts, Fidelity E&P

Year	Operator	Total AL (PC or PJ)	AL on Federal Surface	AL on Other Surface
1	Fidelity E&P	10	4	6
2	Fidelity E&P	25	10	15
3	Fidelity E&P	50	20	30
Life of Field (Total AL operating at a time)	Fidelity E&P	350	150	200

Table 2.2-6. Artificial Lifts, Noble

Year	Operator	Total AL (PC or PJ)	AL on Federal Surface	AL on Other Surface
1	Noble	100	65	35
2	Noble	75	50	25
3	Noble	75	50	25
Life of Field (Total AL operating at a time)	Noble	550	165	85

Table 2.2-7. Artificial Lifts, Omimex

Year	Operator	Total AL (PC or PJ)	AL on Federal Surface	AL on Other Surface
1	Omimex	5	3	2
2	Omimex	5	3	2
3	Omimex	10	2	3
Life of Field (Total AL operating at a time)	Omimex	30	20	10

Table 2.2-8. Artificial Lifts, Decker

Year	Operator	Total AL (PC or PJ)	AL on Federal Surface	AL on Other Surface
1	Decker	14	12	2
2	Decker	14	12	2
3	Decker	14	12	2
Life of Field (Total AL operating at a time)	Decker	60	40	20

Assumptions:
1. Company continues to install siphon strings as opposed to AL.
2. Company converts selected wells to siphon strings.
3. Average 10 new wells per year for 30 years = 300 wells.
4. Average 20% of total wells will be AL = 60 wells.

The two options for AL equipment, progressive cavity (PC) and pumpjack (PJ), are discussed below.

Option 1: Progressive Cavity Pump (PC pump) – Installation and Use

Production site requirements

The use of a PC pump would not expand the footprint of the existing well site. The PC pump would be located within the well site location, with the footprint being approximately 3.5 x 16 feet. The PC pump would be installed on the well head inside the existing well house. If powered by a generator, the generator would sit outside the well house within the well site footprint. The generator would be approximately 28 x 58 inches and 34 inches high.

Installation requirements

A truck-mounted rig would be needed to modify the well and install the required tubing and rods (this would also likely be needed for other AL methods, since the production tubing is too small in diameter for any AL method).

Operational requirements

PC pumps would be powered by an electric motor or a natural gas-fired generator. Because of the small amount of available electrical power, approximately 80 percent of AL applications would have a generator as a power source. In areas where electrical power is within a close radius of a proposed location, electrical power could be considered, either above or below ground when needed.

The typical generator used on PC pumps has a 4-stroke, lean-burn, natural gas-fired engine ranging from 8.8 to 26.2 horsepower (hp) in size. The engines would meet emissions levels of similarly sized diesel-fired Tier 4 certified engines. The natural gas-fired generators would operate continuously and normally run at very low revolutions per minute (rpm). At 500 rpm, the estimated output for an average-size engine used in the BNGPA is 4 hp, and its gas consumption is approximately 1,000 standard cubic feet per day (mscfd).

Anticipated sound levels

Generator-powered PC pumps have sound readings of 80 decibels (dBA) at 100 percent load and 63 dBA at a 50 percent load with the use of a ‘quiet package’ or increased muffling. If electrical power were utilized the noise reading would be negligible.

Water production

The use of PC pumps would increase a well’s water production (as well as natural-gas production) over the near term (preliminary data indicates that per-well water production may be up to 15 BWPD with the initiation of AL). This rate of water production would decline approximately 5–8 percent per year. The increased water production would likely exceed what could be handled by the existing evaporation pit at each location. Water-hauling by truck to a central evaporation facility (discussed under Produced Water) would likely be required.

Maintenance requirements

PC pumps can run for approximately three years before any well or tubing maintenance is required. Generators for PC pumps require an oil change every 30–60 days, which would have the same environmental impact as a typical site visit to the site by the pumper.

Visual impacts

Since the PC pump would be enclosed in a well house that is painted with the current BLM-approved color, there would be no additional visual impact. If the PC pump were powered by a generator, the generator case could be colored to minimize the visual impact; this would be unnecessary if electrical power were used.

Option 2: Pumpjack Unit – Installation and Use

The use of a pumpjack would not expand the footprint of the existing wellsite. Within the wellsite location, the pumpjack footprint would be approximately 16 x 3.5 feet. Maximum height during stroke is approximately 13.5 feet.

Installation Requirements

A truck-mounted rig would be needed to modify the well and install the required tubing and rods (this would also likely be needed for other AL methods, since the small diameter production tubing is too small for any AL method). The skid-mounted pumpjack would be placed on approximately two inches of crushed rock, which would serve as the base/foundation for the installation. There would be no permanent structure associated with the pumping unit.

Operational requirements

Pumpjacks would be powered by an electric motor or a natural gas-fired generator. Because of the small amount of available electrical power, approximately 80 percent of AL applications would have a generator as a power source. In areas where electrical power is within a close radius of a proposed location, electrical power could be considered, either above or below ground when needed.

The typical generator used on pumpjacks has a 4-stroke, lean-burn, natural gas-fired engine ranging from 8.8 to 26.2 hp in size. The engines would meet emissions levels of similarly sized diesel-fired Tier 4 certified engines. The natural gas-fired generators would operate continuously and normally run at very low rpm. At 500 rpm, the estimated output for an average-size engine used in the BNGPA is 4 hp, and its gas consumption is approximately 1 mscfd.

Anticipated sound levels

The engine-powered pumpjack measurements at the factory suggest that factory-installed mufflers limit the sound of the engine to approximately 86 dBA at a distance of one meter directly in front of the exhaust outlet, while the noise level was 71.2 dBA at a distance of one meter and at a 90° angle from the exhaust outlet. In certain areas within the BNGPA, an Operator has worked with BLM to install ‘hospital-grade’ (or equivalent) mufflers, and BLM reviewed these field installations. These mufflers are expected to achieve a 35–40 dBA reduction in noise levels. One reference suggests that the noise level may be approximately 40 dBA at a distance of 7–10 meters from the source (see Table 4.15-1).

Water production

The use of pumpjacks would increase a well’s water production (as well as natural-gas production) over the near term (preliminary data collected by Noble Energy indicates that per-well water production would be up to 15 BWPD with the initiation of AL). This rate of water production would decline approximately 5–8 percent per year. The increased water production would likely exceed what can be handled by the existing evaporation pit at each location. Water-hauling by trucks to a central evaporation facility (discussed under Produced Water) would likely be required.

Maintenance requirements

Generators for pumpjack engines require an oil change every 30–60 days, which would have the same environmental impact as a typical site visit by the pumper.

Visual impacts

The pumpjacks may create a greater visual impact than other AL methods, primarily due to size. BLM and surface owners identify painting of pumpjacks and other equipment to minimize impacts. The Operators would work with BLM and the surface owners to determine methods to minimize visual impacts such as the application color schemes that blend into the landscape.

Power Sources

The Operators anticipate the need for external power sources to support the BNGPA, particularly for the use of artificial lift. These power sources include the use of solar, wind, natural gas engines, and electrical lines. If and when additional power lines are needed for electricity necessary to produce the natural gas, the respective Operator would make a site-specific proposal. The proposal would address site-specific issues including, but not limited to, topography, land-owner and regulatory desires, and cultural and wildlife resources. The Operators would attempt to employ BMPs to minimize impacts associated with the proposal.

Gas-Gathering Operations

Typical operations include the gathering of natural gas via gathering lines. These gathering lines bring the gas to strategically placed field compressors. The gas is then compressed by field compressors (Bitter Creek) and delivered to four field outlets. These outlets are Williston Basin Interstate Pipelines' (WBIP) Saco Compressor Station, Omimex's Whitewater Compressor Station, WBIP's Malta Delivery Point, and WBIP's Whitewater Delivery Point.

- The WBIP Saco Compressor Station sends gas to the east past Hinsdale, Fort Peck, Glasgow, Vida, and ends north of Glendive. Montana Dakota Utilities (MDU) has firm capacity on this line and uses the capacity to serve all the towns located along this route. From north of Glendive, MDU can route the gas to many different markets, as well as to storage.
- The Omimex Whitewater Compressor Station sends gas north to the Northern Border Pipeline, which has markets in the mid-continent areas.
- The WBIP Malta Delivery Point takes gas from a Bitter Creek field compressor station and delivers it to the Malta town border station. MDU uses this gas to serve the town of Malta.
- The WBIP Whitewater Delivery Point takes gas from a Bitter Creek gathering line and delivers it to the Whitewater town border station. MDU uses this gas to serve the town of Whitewater.

Following is the current breakdown of produced gas destinations as of March 2006:

- WBIP Saco..52%
- Omimex Whitewater 46%
- WBIP Malta Delivery..2%
- WBIP Whitewater Delivery ....<1%

This breakdown does not take into consideration the in-field usage for compressor fuel, catalytic heaters, meter-shed stoves, farm taps, or similar uses.

Gas Compression

The Operators are proposing the addition of four new compressor stations. Three of the four stations would be 300 feet x 300 feet in size while the fourth would be 500 feet x 500 feet. Total surface disturbance for the compressor stations would be approximately 12.0 acres. Each site would have one new compressor. Two of the four stations would be powered by 600-hp compressors (Ajax DPC-2803LE units) and the other two would be powered by 400-hp compressors (Ajax DPC 2802LE units). In addition, the Operators are proposing to add two 400-hp compressors to existing compressor stations (East Saco and West Saco). Table 2.2-9 shows proposed compression for the BNGPA. Additional compression may be proposed as field conditions warrant and may be subject to additional NEPA analysis.

Table 2.2-9. Proposed Gas Compression

Station	Station Unit #	Description	HP	Field	GEOGRAPHICAL LOCATION			
					County	Section	Twp	Range
N Saco	#1	Ajax DPC-2803LE	600	Bowdoin East	Phillips	6	32N	34E
SE Nelson	#1	Ajax DPC-2803LE	600	Bowdoin East	Phillips	31	32N	33E
Cole	#1	Ajax DPC-2802LE	400	Bowdoin East	Phillips	7	32N	33E
System H	#1	Ajax DPC-2802LE	400	Bowdoin West	Phillips	33	37N	30E
East Saco	#2	Ajax or Screw	400	Bowdoin East	Valley	25	32N	34E
West Saco	#2	Ajax or Screw	400	Bowdoin East	Phillips	26	32N	33E
Total proposed hp			2,800					

2.2.5 Applicant-Committed Measures

Following are mitigation measures and agency-required procedures on public lands to avoid or mitigate resource or other public land-use impacts. These measures would be applied on privately owned surface and State of Montana lands only if the oil and gas estate is federally administered or unless otherwise specified by the involved private and/or the State surface owners**.** An exception to a mitigation measure and/or design feature may be approved on public land on a case-by-case basis when deemed appropriate by the BLM. An exception would be approved only after a thorough, site-specific analysis determined that the resource or land use for which the measure was put in place is not present or would not be significantly impacted.

2.2.5.1 Preconstruction Planning and Design Measures

The Operators and the BLM would make on-site interdisciplinary inspections of each proposed and staked facility site (e.g., well sites), new access road, and pipeline alignment project so that site-specific recommendations and mitigation measures can be developed.

- New road construction and maintenance of existing roads in the BNGPA would be accomplished in accordance with BLM Manual 9113 standards unless private land-owners or the State of Montana specify otherwise.
- The Operators would prepare and submit an APD for each drill site on federal leases to the BLM for approval prior to initiation of construction. Also prior to construction, the Operators or their contractors would submit a Sundry Notice and/or right-of-way application for each pipeline and access road segment on federal leases. The APD would include a Surface Use Plan that would show the layout of the drill pad over the existing topography, dimensions of the pad, volumes and cross-sections of cut-and-fill, location and dimensions of reserve pit, and access-road egress and ingress. The APD, Sundry Notice, and/or right-of-way application plan would also itemize project administration, time frame, and responsible parties. In addition, a reclamation plan would be developed by the Operators for each facility in consultation with the BLM.
- The Operators would slope-stake construction activities when required by the BLM (e.g., steep and/or unstable slopes) and receive approval from the BLM prior to the start of construction.

2.2.5.2 Resource-Specific Requirements

The Operators propose to implement the following resource-specific mitigation measures and agency requirements.

Geology/Minerals/Paleontology

Mitigation measures presented in the Soils and Water Resources sections would avoid or minimize many of the potential impacts to the surface mineral resources. Protection of subsurface mineral resources from adverse impacts would be provided by the BLM casing and cementing policy.

Paleontological resource values would be protected through the following mitigation measure:

- If recommended by the BLM, survey each proposed facility located in areas with known and potential vertebrate paleontological resource significance (Class II) using a BLM-approved paleontologist prior to surface disturbance (BLM 1987*b*; 1990*a*). If paleontological resources are discovered at any time during construction, halt all construction activities and immediately notify BLM personnel. Work would not proceed until paleontological materials are properly evaluated by a qualified paleontologist.

Climate and Air Quality

- Prohibit burning of garbage or refuse at the drill sites or other facilities.
- When an air quality, soil loss, or safety problem is identified as a result of fugitive dust, initiate immediate abatement. The BLM would approve the procedure (e.g., application of water and magnesium chloride) for dust abatement at facility construction sites as well as locations for use and application rates. Water, if approved for this purpose, must be obtained by the Operator from State-approved source(s).

Soils

- Reduce the area of disturbance to the absolute minimum necessary for construction and production operations while providing for the safety of personnel (see Table 2.3-1, page 2-

39, Soils, Approximate Area of Disturbance). The Operators would restrict off-road vehicle activity.

- Where feasible, locate buried pipelines immediately adjacent to roads to avoid creating separate areas of disturbance and in order to reduce the total area of disturbance.
- Avoid using frozen or saturated soils as construction material.
- Minimize construction activities in areas with soils that have a severe erosion hazard, and apply special slope-stabilizing structures if construction cannot be avoided in these areas.
- Avoid development on areas where erosion cannot be effectively controlled/mitigated and reclamation to BLM standards is likely to be unsuccessful.
- Design cutslopes in a manner that would allow retention of topsoil, application of surface treatments, such as mulch, and subsequent revegetation.
- Selectively strip and salvage topsoil from all disturbed areas to an average depth of four to six inches at each location.
- Where possible, minimize disturbance to vegetated cut-and-fill areas on existing improved roads.
- Install runoff and erosion control measures such as water bars, berms, and silt fences if needed, as prescribed in **Appendix D—Reclamation Plan**.
- Inspect all runoff and erosion-control structures on a regular schedule, and after major runoff events. During inspection, clean and maintain the control structures in functional condition. Conduct inspection and maintenance on schedule for the duration of construction, drilling, production, and final reclamation until successful revegetation and soil stability is attained.
- Complete interim reclamation to minimize the footprint of disturbance on all areas where final reclamation procedures cannot be promptly implemented. Interim reclamation measures include recontouring, spreading topsoil, and seeding and/or implementing erosion- and weed-control measures.
- Implement final reclamation measures when all disturbance and use of an area are finished. Final reclamation will serve to return the area to the approximate pre-disturbance condition and set the course for eventual ecosystem restoration. Final reclamation procedures may include recontouring, respreading topsoil, ripping, erosion and weed control, seeding, and grazing deferment.
- Conduct monitoring and maintenance of final reclamation, to include observing and measuring the success of final reclamation efforts, and determine if further reclamation efforts are needed.
- To prevent or minimize impacts caused by vehicle travel on wet roads, allow vehicle traffic on BNGPA roads only during dry or frozen conditions. Alternatively, improve roads in areas with high traffic-use patterns.

Water Resources

- Limit construction of drainage crossings to no-flow periods or low-flow periods.
- Minimize the area of disturbance within ephemeral and intermittent drainage channel environments.

- Prohibit construction of well sites, access roads, and pipelines within 500 feet of surface water and/or riparian areas. Exceptions would be granted by the BLM based on an environmental analysis and site-specific mitigation plans.
- Implement minor routing variations during access road layout to avoid steep slopes adjacent to ephemeral or intermittent drainage channels. Maintain a 100-foot-wide buffer strip of natural vegetation where possible (not including wetland vegetation) between all construction activities and ephemeral and intermittent drainage channels.
- Do not install culverts on ephemeral drainages. The use of culverts on intermittent drainage crossings would be analyzed on a case-by-case basis. Design all drainage-crossing structures to carry 25- to 50-year discharge events, or as otherwise directed by the BLM.
- Design channel crossings to minimize changes in channel geometry and subsequent changes in flow hydraulics.
- Maintain vegetation barriers occurring between construction activities and ephemeral and intermittent channels.
- Minimize construction activities in areas of steep slopes and install special slope-stabilizing structures if construction cannot be avoided in these areas.
- Install runoff- and erosion-control measures such as water bars, berms, and interceptor ditches as needed.
- Include adequate drainage-control devices and measures in the road design (e.g., road berms and drainage ditches, diversion ditches, cross drains, culverts, out-sloping, and energy dissipators) at sufficient intervals and intensities to adequately control and direct surface runoff above, below, and within the road environment, in order to avoid erosion-concentrated flows. Use erosion-control devices in conjunction with the surface runoff and drainage-control devices and measures such as temporary barriers, ditch blocks, erosion stops, mattes, mulches, and vegetative covers. Implement a revegetation program as soon as possible to re-establish the soil protection afforded by a vegetal cover.
- Design and construct interception ditches, sediment traps, water bars, and revegetation and soil stabilization measures if needed.
- Construct channel crossings for buried pipelines such that the pipe is buried a minimum of four feet below the channel bottom.
- Regrade disturbed channel beds to the original geometric configuration with the same or very similar bed material.
- Upon completion of construction activities, restore topography to near pre-existing contours at well sites and other facility sites, and along access roads and pipelines. Replace up to 12 inches of topsoil or suitable plant-growth material over all disturbed surfaces. Apply fertilizer, seed (specified in a reclamation plan), and mulch as required.
- Ensure that the project complies with EO 11990 (floodplains protection) and RMP management directives that relate to protection of water resources identified in Section 4.4.2 These regulations require avoidance of stream channels to the maximum practicable extent. Where total avoidance is not practicable, implement measures to minimize impacts to streams and associated floodplains/floodways. Where streams and floodplains cannot be avoided, the Operators would be required to show the BLM AO why such resources cannot be totally avoided and how impacts would be minimized during the APD process.

- Case wells during drilling, and case and cement all wells in accordance with Onshore Order No. 2 to protect accessible high-quality aquifers. High-quality aquifers are those with known water quality of 10,000 ppm TDS or less. The protection of high-quality aquifers involves well casing and welding of sufficient integrity to contain all fluids under high pressure during drilling and well completion. Further, ensure that wells adhere to the appropriate BLM cementing policy.
- Construct reserve pits so that a minimum of one-half of the total depth is below the original ground surface on the lowest point within the pit. To prevent seepage of fluids, utilize drilling mud gel or poly liners to line reserve pits in areas where subsurface material would not contain fluids. Liners would be of sufficient strength and thickness to withstand normal installation and use. The liner would be impermeable (i.e., having a permeability of less than 10^{-7} cm/sec) and chemically compatible with all substances which may be put in the pit.
- Maintain two feet of freeboard on all reserve pits to ensure the reserve pits are not in danger of overflowing. Shut down drilling operations until the problem is corrected if leakage is found outside the pit.
- Extract hydrostatic test water used in conjunction with pipeline testing and all water used during construction activities from sources with sufficient quantities and through appropriation permits approved by the State of Montana.
- Discharge all concentrated water flows within access road rights-of-way onto or through an energy dissipater structure (e.g., rip-rapped aprons and discharge points) and discharge into undisturbed vegetation.
- Develop and implement a storm-water pollution plan for storm-water runoff at drill sites as required per MDEQ storm water MPDES permit requirements.
- Coordinate with the COE to determine the specific Clean Water Act (CWA) Section 404 Permit requirements and conditions (including the potential requirement of compensatory mitigation) for each facility that occurs in Waters of the U.S. to prevent the occurrence of significant impact to such waters.
- Ensure that the project must comply with all applicable requirements of the CWA, including the requirement to obtain an MPDES permit.

Vegetation and Wetlands

- Seed and stabilize disturbed areas with mixtures and treatment guidelines prescribed in the approved APD/right-of-way.
- Evaluate all project facility sites for occurrence and distribution of waters of the U.S., special aquatic sites, and jurisdictional wetlands. Locate all project facilities out of these sensitive areas. If complete avoidance is not possible, minimize impacts through modification and minor relocations. Coordinate activities that involve dredge or fill into wetlands with the COE.
- Conduct site-specific surveys for federally listed threatened and endangered, candidate, and proposed plant species, and plant species of special concern prior to any surface disturbance in areas determined by the BLM to contain potential habitat for such species. If such plant species or their habitat are found during the surveys, minor adjustments to the location of project facilities would be made to avoid the plant species and/or their habitat. Copies of these surveys would be provided to the BLM.

Range Resources and Other Land Uses

- Coordinate with the affected livestock operators to ensure that livestock control structures remain functional during drilling and production operations.

Wildlife

- Unless an exception is granted by the BLM, prevent disturbance in habitats designated as big game winter range between December 1 and May 15.
- Within big game winter ranges, locate disturbances so that specific important vegetation types, as identified by the BLM, would be avoided where possible.
- During reclamation, establish a variety of forage species that are useful to resident herbivores by specifying the seed mixes in the approved APD/right-of-way.
- Prohibit surface disturbance within 1/4 mile of Greater sage-grouse leks unless they are considered historic (have not been used in the past 7–10 years).
- Prohibit surface disturbance within two miles of an active or known Greater sage-grouse lek between March 1 and June 30, unless excepted.
- Prohibit surface disturbance within identified patches of Greater sage-grouse severe winter habitat.
- Manage produced water to reduce the spread of West Nile virus within sage-grouse habitat areas. Implement the following impoundment construction techniques and measures to eliminate water sources that support breeding mosquitoes:
  - Overbuild the size of ponds to accommodate a greater volume of water than is discharged. This will result in non-vegetated and muddy shorelines that breeding mosquitoes avoid.
  - Build steep shorelines to reduce shallow water and aquatic vegetation around the perimeter of impoundments. Construction of steep shorelines also will increase wave action that deters mosquito production.
  - Maintain the water level below rooted vegetation for a muddy shoreline that is unfavorable habitat for mosquito larvae. Rooted vegetation includes both aquatic and upland vegetative types. Always avoid flooding terrestrial vegetation in flat terrain or low-lying areas.
  - Use a horizontal pipe to discharge inflow directly into existing open water, thus precluding shallow surface inflow and accumulation of sediment that promotes aquatic vegetation.
  - Fence pond site to restrict access by livestock and other wild ungulates that trample and disturb shorelines, enrich sediments with manure, and create hoof-print pockets of water that are attractive to breeding mosquitoes.
  - Use adulticides to target adult mosquito populations and larvicides to control the hatching of mosquito larvae, using approved pesticides and utilizing licensed applicators with a Pesticide Use Plan.
- Prohibit disturbance during the critical nesting season (March 1–August 31, depending on species) within one mile of an active nest of listed or sensitive raptor species, and 3/4–1/2 mile (depending upon species or line of sight) of an active nest of other raptor species. The

nature of the restrictions and the protection radius would vary according to the raptor species involved and would be determined by the BLM.

- In the event of a 'taking' of a raptor nest, acquire all appropriate permits.
- Prohibit disturbance of potential mountain plover nesting habitat in a given year from April 1–July 31 unless surveys are conducted to determine mountain plover presence/absence. Survey protocol would follow current BLM and FWS standards. If surveys of an area are conducted for three consecutive years and no mountain plovers are observed, the area may be cleared.
- Locate surface disturbance 50m or more from the edge of black-tailed prairie-dog colonies, where feasible.
- Conduct surveys for black-footed ferrets if a portion of a black-tailed prairie-dog colony that provides suitable black-footed ferret habitat is to be disturbed.
- Prohibit unnecessary off-site activities of operational personnel in the vicinity of the drill sites.
- Inform all project employees of applicable wildlife laws and penalties associated with unlawful take and harassment.
- Require that regular drivers undergo training to avoid vehicular collisions and the means that can be employed to minimize them.
- Implement reduced speed limits to reduce potential for vehicle/wildlife collisions.
- To protect migratory birds and wildlife in general, fence and net all reserve pits and other pits and areas that potentially contain hydrocarbon materials in accordance with BLM requirements.

Recreation

- Minimize conflicts between project vehicles/equipment and recreation traffic by posting appropriate warning signs, implementing operator safety training, and requiring project vehicles to adhere to low speed limits.
- Incorporate appropriate environmental BMPs into APDs and associated rights-of-way to mitigate anticipated impacts to surface resources in and near the developed recreation sites and the cabin sites around Nelson Reservoir in accordance with BLM Instruction Memorandum No. 2007-021 and BOR regulations.

Visual Resources

- Incorporate appropriate environmental BMPs into APDs and associated rights-of-way to mitigate anticipated impacts to surface resources on VRM Class II lands (approximately 31,535 acres) and VRM Class III lands (approximately 94,437 acres) (BLM 1994a; BLM 1994*b*) in accordance with BLM Instruction Memorandum No. 2007-021.

Cultural Resources

- If a site is determined eligible, or is listed on the National Register of Historic Places (NRHP), avoidance is the preferred alternative.
- If avoidance is not feasible, employ the plan developed by the BLM to mitigate the adverse effects associated with development.

- If cultural resources are discovered at any time during construction, cease all construction activities and immediately notify BLM personnel. Work shall not resume until a Notice to Proceed is issued by the BLM.

Socioeconomics

- Implement hiring policies that would encourage the use of local or regional workers who would not have to relocate to the area.
- Coordinate project activities with ranching and farming operations to minimize conflicts involving livestock movement and other farm and ranch operations. This would include scheduling project activities to minimize potential disturbance of large-scale livestock movements. Establish effective and frequent communication with affected ranchers and farmers to monitor and correct problems and coordinate scheduling.

Transportation and Access

Develop and maintain all roads in accordance with the Transportation Plan and Surface Operations Section of the Master APD for Phillips County and all fields/units/leases (federal) west of Hinsdale in Valley County (BLM undated). In addition:

- Use existing roads whenever possible.
- Block, reclaim, and revegetate roads on public lands that are not required for routine operation and maintenance of producing wells and ancillary facilities. Roads on private lands would be treated similarly depending on the desires of the land-owner.
- Provide all drivers with a training session describing the types of wildlife species in the area that are susceptible to vehicular collisions to reduce the potential for vehicle/big game collisions. The circumstances under which such collisions are likely to occur, and the measures that could be employed to minimize them, should be discussed. Reduced speed limits would be implemented to reduce potential for vehicle/wildlife collisions.
- Where possible, avoid areas with important resource values, steep slopes, and soils with a severe erosion hazard and low reclamation potential in planning for new roads.
- Employ preventive and corrective maintenance of non-county roads in the project area throughout the duration of the project. This may include blading, cleaning ditches and drainage facilities, dust abatement, noxious weed control, or other requirements as directed by the BLM or other land-owners.
- If desired by the BLM and Phillips and Valley counties, engage in a coordinated planning process for the development and maintenance of roads within the BNGPA.

Health and Safety

- Recycle drilling mud, to the extent feasible.
- Continue the practice of providing drilling mud to private land-owners for use as stock-pond sealant.
- For exotic drilling mud operations, use closed-loop systems with above-ground steel tankage.
- Recycle completion fluids, to the extent feasible.

- Provide receptacles for management of trash and construction debris generated during construction and operations prior to transport in closed containers to a county sanitarian-approved landfill for disposal.
- Provide toilet facilities for field operations.
- Recycle used oil and methanol, to the extent feasible.
- Investigate the feasibility of using produced water in well drilling and completion processes.
- Use lined produced-water evaporation pits at high-volume central facilities.
- To minimize undue exposure to hazardous situations, require measures that would preclude the public from entering hazardous areas and place warning signs alerting the public to truck traffic.
- Institute a Hazard Communication Program for all Operator employees and require subcontractor programs in accordance with OSHA 29 CFR 1910.1200. These programs are designed to educate and protect the employees and subcontractors with respect to any chemicals or hazardous substances that may be present in the work place. As every chemical or hazardous material is brought on location, require that a Material Safety Data Sheet accompany that material and become part of the file kept at the field office as required by 29 CFR 1910.1200. Ensure that all employees receive the proper training in storage, handling, and disposal of hazardous substances.
- Inventory and report chemical and hazardous materials in accordance with the Superfund Amendments and Reauthorization Act (SARA) Title III 40 CFR Part 335, if quantities exceeding 10,000 pounds or the threshold planning quantity (TPQ) are to be produced or stored in association with the Proposed Action. Submit the appropriate Section 311 and 312 forms at the required times to the state and county emergency management coordinators and the local fire departments.
- Transport and/or dispose of any hazardous wastes, as defined by the Resource Conservation and Recovery Act (RCRA), in accordance with all applicable federal, state, and local regulations.
- The Operators plan to design operations to severely limit or eliminate the need for extremely hazardous substances. The Operators also plan to avoid the creation of hazardous wastes as defined by RCRA wherever possible.
- **Appendix C—Hazardous Materials Management Plan**, provides a summary of the hazardous chemicals that may be found on a drilling or production site with examples of representative chemicals and associated physical and health hazards. At this time it is impossible to determine if these items would be stored in sufficient quantities to require reporting under the Superfund Amendments and Reauthorization Act, Title III, and in some cases, the items may not be on site at all. However, all items would become part of the Hazard Communications Plan where required, and employee training would be completed as required.
- Write and implement Spill Prevention Control and Counter-Measures (SPCC) Plans as appropriate in accordance with 40 CFR Part 112 to prevent discharge of oil into navigable waters of the United States.

Noise

- Muffle and maintain all motorized equipment according to manufacturers' specifications in an effort to achieve the recommended standard of 55 dBA (with an average day/night noise level of 49 dBA) for noise impacts to sensitive receptors at 1/4 mile from the source. When background noise exceeds 55 dBA, noise levels will be no greater than 5 dBA above background at 1/4 mile.
- To reduce the impact of noise generated by field traffic, install remote monitoring systems such as Supervisory Control and Data Acquisition (SCADA) or computer-assisted operations (CAOs), where feasible.

2.3 COMPARISON OF ALTERNATIVES

Table 2.3-1 compares the major components of the three alternatives. Table 2.3-2 compares the major effects identified in Section 4 from each of the alternatives.

Table 2.3-1. Bowdoin Natural Gas Project—Comparison of Alternatives

Project Component	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development Alternative
Well Drilling Activities:			
Number and land status of gas wells in the BNGPA	• 360 new and 198 existing private wells on 558 private surface locations • 40 new and 22 existing state wells on 62 locations	• 360 new and 198 existing private wells on 558 private surface locations. • 40 new and 22 existing state wells on 62 locations. • 420 new and 215 existing federal wells on 635 locations.	• 546 new and 301 existing private wells on 847 private surface locations. • 61 new and 33 existing state wells on 94 locations. • 638 new and 326 existing federal wells on 964 locations.
Drilling Actions	620 private and state gas wells would be drilled by conventional gas well-drilling rigs to depths of approximately 1,000 feet to 3,000 feet. Fresh water would be used in the drilling operations. A minimum of 150 feet of 7-inch steel surface casing would be cemented in place from ground surface with a minimum of three centralizers installed to protect any water aquifers. With a BOP in place for pressure control, the well would be drilled to approximately 400 feet deeper than the top of the Phillips/Greenhorn formation. 4.5-inch production casing would be centralized and cemented from the surface to the total depth of the well. Anticipated drilling period to last approximately 10–15 years.	1,255 private, state, and federal wells would be drilled in the same manner as described in Alternative A. Anticipated drilling period to last approximately 10–15 years.	1,905 private, state, and federal wells would be drilled in the same manner as described in Alternative A. Anticipated drilling period to last approximately 10–15 years.

Project Component	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development Alternative
Disposal of wastes	The 558 proposed private wells at 558 locations and 62 state wells at 62 locations would have a 60'L x 12'W x 4' or 6'D reserve pit for the disposal of drill cuttings, water, drilling mud and excess cement. The reserve pits would be fenced on three sides and the fourth would be fenced after the drilling rig has moved off of the location. BLM requires reserve pit fluids to be removed immediately upon well completion. Recycling reserve pit fluids within the field is standard practice. Upon removal or evaporation of fluids, pit closure occurs with the backfill of soil and its compaction to prevent settling. This would occur within one year after the drilling and completion of the well. Wastes would be contained on-site and disposed of at the Saco landfill. Chemical 'porta-potties' would be used during active construction, and at drilling site locations.	1,255 proposed private, state, and federal wells at 1,255 locations would be managed in the same manner as described in Alternative A.	1,905 proposed private, state, and federal wells at 1,905 locations would be managed in the same manner as described in Alternative A.
Production Support Facilities:			
Field Compressor Stations	• 16 existing stations: Bitter Creek Pipelines (15 stations), Omimex Canada (1 station). • 4 proposed stations, all Bitter Creek Pipelines. Approximate surface disturbance would be 12.0 acres.	• 16 existing stations: Bitter Creek Pipelines (15 stations), Omimex Canada (1 station). • 4 proposed stations, all Bitter Creek Pipelines. Approximate surface disturbance would be 12.0 acres.	• 16 existing stations: Bitter Creek Pipelines (15 stations), Omimex Canada (1 station). • 4 proposed stations, all Bitter Creek Pipelines. Approximate surface disturbance would be 12.0 acres.

Project Component	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development Alternative
Gas Pipelines & Electrical Lines	Approximately 104 miles plowed for private and state, 5.1-foot-wide corridor and 104 miles ditched for private and state, 25-foot-wide corridor. Total surface disturbance would be 378 acres, all short-term. Buried plastic and steel flowline to carry gas from each well of the 400 proposed and 220 existing wells to the compressor stations. Multiple flowlines would be placed in the same trench. Trenches would parallel roads to extent feasible.	Approximately 210 miles plowed for federal, private, and state, 5.1-foot-wide corridor and 210 miles ditched for federal, private, and state, 25-foot-wide corridor. Total surface disturbance would be 761.7 acres, all short-term. Buried plastic and steel flowline to carry gas from each well of the 820 proposed and 435 existing wells to the compressor stations. Multiple flowlines would be placed in same trench. Trenches would parallel roads to extent feasible. A BLM-issued right-of-way would be required for any ‘off-lease’ and/or third-party facilities on federal surface.	Approximately 318 miles plowed for federal, private, and state, 5.1-foot-wide corridor and 318 miles ditched for federal, private, and state, 25 feet wide corridor. Total surface disturbance would be 1,156 acres, all short-term. Buried plastic and steel flowline to carry gas from each well of the 1,245 proposed and 660 existing wells to the compressor stations. Multiple flowlines would be placed in same trench. Trenches would parallel roads to extent feasible. A BLM-issued right-of-way would be required for any ‘off-lease’ and/or third-party facilities on federal surface.
Road maintenance and use	• Access would primarily use roughly 207.5 miles of existing and proposed two-track roads. • Earthen materials would come from adjacent locations owned by the land-owner. • Estimated use of access would be 6 vehicles per day per well during the drilling and completion period.	Access would primarily use roughly 420 miles of existing and proposed two-track roads. Materials and road use would be the same as Alternative A.	Access would primarily use roughly 636 miles of existing and proposed two-track roads. Materials and road use would be the same as Alternative A.

Project Component	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development Alternative
Produced Water Management:			
Produced-water evaporation and/or disposal	Each producing well site (400 new and 220 existing private and state) would have a produced-water evaporation pit constructed. Approximately 60% of the new locations would have a 40' x 40' evaporation pit, 30% of the locations would have a 60' x 60' evaporation pit and 10% of the locations would have a 100' x 100' evaporation pit. All pits would be about 5 feet in depth. Approximately 25% of the evaporation pits may require periodic water hauling because of fluctuations in water production. In these cases, the water would be hauled approximately two (2) trips per week to a permitted, central water evaporation pit. All pits would be permitted as required in BLM Operating Order 7 or by MBOGC.	Same as Alternative A for 820 new and 435 existing federal, state, and private wells.	Same as Alternative A for 1,245 new and 660 existing federal, state, and private wells.
Reclamation:			
Reclamation Measures	The surface would be reclaimed in accordance with the agreements with land-owners. Disturbed areas would be seeded with a certified weed-free seed mix agreed to by the NRCS and the surface owner.	The surface would be reclaimed in accordance with the agreements with land-owners. Disturbed areas would be seeded with a certified weed-free seed mix agreed to by the BLM, NRCS and the surface owner.	The surface would be reclaimed in accordance with the agreements with land-owners. Disturbed areas would be seeded with a certified weed-free seed mix agreed to by the BLM, NRCS and the surface owner.
Reclamation Timeframes	Reclamation would take place within 1 year where specific surface-disturbing activities have been completed, and concurrent with other operations in the project area.	Same as Alternative A.	Same as Alternative A.
Monitoring Plans:			
Air Quality	Per MDEQ requirements for testing to demonstrate compliance with emission limits and Annual Emission Inventories.	Same as Alternative A.	Same as Alternative A.

Project Component	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development Alternative
Wildlife	None required.	Monitoring of specific wildlife species is required: • Big game winter range • Raptor nest success and productivity • Bald eagle winter roosts • Greater sage-grouse and sharp-tailed grouse activity • Migratory bird breeding activity • Colonial bird breeding activity • Pre- and post-development monitoring of wetland, grassland, and sagebrush habitats	Monitoring of specific wildlife species is required: • Big game winter range • Raptor nest success and productivity • Bald eagle winter roosts • Greater sage-grouse and sharp-tailed grouse activity • Migratory bird breeding activity • Colonial bird breeding activity • Pre- and post-development monitoring of wetland, grassland, and sagebrush habitats
Soils	Sites would be monitored during various stages of development and reclamation to ensure erosion is limited and soil productivity is returned.	Same as Alternative A.	Same as Alternative A.
Water Quality	Per MDEQ MPDES requirements.	Same as Alternative A.	Same as Alternative A.

Table 2.3-2. Bowdoin Natural Gas Project—Summary Comparison of Effects

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Air Quality:				
Pollutant Concentrations	The area of the proposed project is currently classified as attainment/ unclassified for NAAQS and therefore considered to be in compliance with ambient air quality standards. Existing criteria pollutant concentrations comply with MAAQS and NAAQS.	Impacts would be less than Alternative B. Project would be in compliance with all MAAQS and NAAQS. Pollutant concentrations would be below PSD increments.	Project would be in compliance with all MAAQS and NAAQS. Pollutant concentrations would be below PSD increments. Emissions information and a detailed ambient analysis can be found in Section 4.1.2.	Same as Alternative B except construction emissions, and therefore impacts, are expected to be slightly higher due to the larger number of wells being developed. Project would be in compliance with all MAAQS and NAAQS. Pollutant concentrations would be below PSD increments.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Visibility	Continuous visibility-related optical background data were collected at the MDEQ-ARMB Class I Fort Peck Indian Reservation and the PSD Class I U.L. Bend Wilderness Area, as part of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program. Visibility for the region is considered very good, with an average SVR of over 150 km (Malm, 2000).	Impacts would be less than Alternative B.	Project would not contribute significantly to visibility degradation at the federal PSD Class I UL Bend Wilderness Area, and MDEQ-ARMB Class I Fort Peck Indian Reservation.	Similar to Alternative B.
Atmospheric Deposition	Atmospheric deposition monitoring at the Theodore Roosevelt National Park CASTNET site show consistent trends from 1999 to 2004 with no overall increase in total deposition over that period.	Impacts would be less than Alternative B	Project would not contribute significantly to total atmospheric deposition at the federal PSD Class I UL Bend Wilderness Area, and MDEQ-ARMB Class I Fort Peck Indian Reservation.	Similar to Alternative B.
Cultural Resources:				
National Register listed or eligible sites	One site is currently listed and 45 sites are eligible, out of 1,420 sites surveyed in the BNGPA. Two NHRP-eligible sites are within an ACEC and protected from development.	This Alternative will not affect cultural resources on federal surface or split estate lands (private surface/federal minerals).	Where adverse effects cannot be avoided, appropriate measures to mitigate the adverse effects will be negotiated between the BLM, the MT SHPO and possibly, depending upon the site, the tribes or local historical societies.	Same as Alternative B.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Areas of traditional cultural value	The Larb Hills is an important plant-gathering location for the Fort Peck tribe	Sites and areas of Traditional Native American concern would continue to be vulnerable to impacts from development on private lands	Developments will provide increased access to kinnikinnick and other ceremonial/medicinal plants. At the same time, these ground disturbances will potentially destroy important gathering locations. The BLM will work with the tribes to minimize impacts to areas with high concentrations of important traditional plants.	Same as Alternative B.
Geology and Minerals:				
Natural Gas Develop-ment	The natural gas resources of the Bowdoin Dome have been known since before World War I. Production on this structure is chiefly from relatively shallow (< 3,000-foot) reservoirs in the Upper Cretaceous Carlile Shale, Mowry/Greenhorn Formations, and Belle Fourche Shale, and is from a combination of stratigraphic and structural traps.	This alternative will allow for development of gas reserves under state and private lands, but since no wells will be drilled on federal lands, no federal reserves or revenues will be produced.	Natural gas reserves developed under federal, state and private lands will eventually be depleted. Recovery of gas reserves would generate federal, state and private revenues.	Same as Alternative B.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Hydrology: Surface Water Resources				
Increased turbidity, salinity and sedimentation of surface waters due to runoff from disturbed areas (e.g., roads).	Water quality constituents of concern for the BNGPA include total suspended solids, salinity, total dissolved solids, nutrient enrichment, and some trace metals. Erosive and saline soils occur within the BNGPA.	Minimal effects, with the proper use of construction techniques, drilling practices, proper operating procedures, use of evaporation ponds, successful reclamation, and the adherence to applicable federal (CWA Section 404 & 401), state (MBOGC, MDEQ), and local water quality (Conservation District) laws/guidelines and regulations. MBOGC would be the primary permitting agency on the state and private wells under this Alternative.	Minimal effects. Same as Alternative A, but with the BLM as the permitting agency on all federal wells/resources, and all federal well construction activities adhering to the BLM Gold Book Standards. Additionally, applicant-committed mitigations may further reduce effects to water resources.	Minimal effects. Same as Alternative B.
Contamination of surface waters from accidental spills or leaks of hydrocarbons.	No hydrocarbon contamination of surface waters currently present within the BNGPA.	Minimal effects with proper construction techniques, drilling practices, operating procedures, use of evapo-ration ponds, successful reclamation, and adherence to applicable federal (CWA Section 404 & 401), state (MBOGC, MTDEQ), and local water quality (Conservation District) laws/guidelines and regulations. MBOGC would be the primary permitting agency on state and private wells.	Minimal effects. Same as Alternative A, but with the BLM as the permitting agency on all federal wells/resources, and all federal well construction activities adhering to BLM Gold Book Standards. Additionally, applicant-committed measures may further reduce effects to water resources.	Minimal effects. Same as Alternative B.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Surface water depletions.	None currently present within the BNGPA.	Insignificant. Water used for the project would be purchased from an existing commercial source.	Insignificant. Same as Alternative A.	Insignificant. Same as Alternative A.
Contamination of surface waters from discharge of unsuitable quality produced water.	None currently present within the BNGPA.	Insignificant. The relatively small amounts of produced water would be disposed of via evaporation from ponds built at well pad sites.	Insignificant. Same as Alternative A.	Insignificant. Same as Alternative A.
Hydrology: Groundwater Resources				
Contamination of groundwater from discharge of produced water, accidental spills/leaks, and/or cross aquifer mixing through wellbores.	Shallow groundwater is generally marginal for domestic use due to high TDS concentrations, but suitable for livestock and wildlife use. Deeper aquifers (> 500 ft. bgs) are generally unsuitable for domestic use due to elevated TDS levels, and are generally too deep to be economical for livestock and wildlife use. The Madison Formation, however, is suitable for domestic use.	Minimal effects, with the proper use of construction and drilling techniques, well completion, and operating procedures as permitted by MBOGC.	Minimal effects. Same as Alternative A, but with the BLM as the permitting agency on all federal wells/resources, and all federal well construction, drilling, completion and construction activities adhering to the BLM Gold Book Standards. Additionally, applicant-committed mitigations may further reduce effects to water resources.	Minimal effects. Same as Alternative B.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Reduced groundwater availability from withdrawal of drilling water.	Shallow groundwater is generally scarce or absent within the BNGPA.	Insignificant. No drawdown of groundwater resources is anticipated, as water used for the project would be purchased from an existing commercial source.	Insignificant. Same as Alternative A.	Insignificant. Same as Alternative A.
Draining of prairie pothole wetlands from pipelines.	Prairie potholes are abundant, but standing water is present perhaps one year in five due to the semi-arid climate.	Minimal effects, with the proper use of road/pipeline construction, drilling techniques, and adherence to permit conditions as regulated by Section 404 of the Clean Water Act and other applicable state and local laws.	Minimal effects. Same as Alternative A, but with the BLM as the permitting agency on all federal wells/resources, and the use of BLM Gold Book Standards for construction. Additionally, applicant-committed mitigations may further reduce effects to water resources.	Minimal effects. Same as Alternative B.
Livestock Grazing:				
Livestock Operations	Approximately 148 cow/calf livestock operations occur within the project area (Kautt 2008).	No impacts to livestock operations.	Produced water may create opportunities for additional water sources and livestock operations may benefit. During production, 10 animal unit months would remain unavailable to livestock operations.	Similar to Alternative B. During production, 25 animal unit months would remain unavailable to livestock operations.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Soils—Approximate area of disturbance:				
Roads (considered long-term disturbance).	318 miles or 463 acres	208 miles or 302 acres	419 miles or 609 acres	636 miles or 925 acres
Wellpads (initial disturbance will be 1 acre per pad; after drilling activities are complete, interim reclamation will reduce disturbance to 0.5 acres per pad).	1,459 wellpads at 0.5 acres in size, for a total of 730 acres.	620 well pads with initial disturbance of 620 acres; reduced to 310 acres of long-term disturbance.	1,255 well pads with initial disturbance of 1,255 acres; reduced to 628 acres of long-term disturbance.	1,905 well pads with initial disturbance of 1,905 acres; reduced to 953 acres of long-term disturbance.
Compressor stations (considered long-term disturbance).	16 compressor stations on 48 acres	4 compressor stations on 12 acres	4 compressor stations on 12 acres	4 compressor stations on 12 acres
Flowlines (considered short-term disturbance)	Assume current flowlines have been fully reclaimed.	377 acres	762 acres	1,156 acres
Social and Economic Conditions:				
Annual Wells drilled	2005: 70 2000: 122 1996–2005 average: 66	2008 - 2012: 54 2013 - 2017: 50 2018 - 2022: 20	2008 - 2012: 110 2013 - 2017: 101 2018 - 2022: 41	2008 - 2012: 166 2013 - 2017: 154 2018 - 2022: 61
Annual average # of rigs operating in the BNGPA	1 rig	1 rig for a shorter period of time than average of the preceding 10 years.	2 rigs for part of drilling season.	3 rigs for part of drilling season.
Annual BNGPA natural gas production	19.2 Bcf in 2005	Estimated at a peak of 18.2 Bcf in 2008 including 15.7 Bcf from existing wells and 2.5 BCF from wells associated with Alternative A, declining to 2.2 Bcf in 2036 2.025 Bcf associated with existing wells and 0.147 Bcf associated with Alternative A wells.	Estimated at a peak of 22.5 Bcf in 2012 including 10.5 BCF associated with existing wells and 12.5 BCF associated with Alternative B wells, declining to 2.3 Bcf in 2036 including 2.025 Bcf associated with existing wells and 0.279 Bcf associated with alternative B wells.	Estimated at a peak of 29.1 Bcf in 2013 including 9.6 Bcf associated with existing wells and 19.5 Bcf associated with Alternative B wells, declining to 2.4 Bcf in 2036 including 2.025 associated with existing wells and 0.423 Bcf associated with Alternative C wells.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Estimated cumulative (2008–2036) BNGPA natural gas production	N/A	290.6 including 193.1 Bcf from existing wells.	380.8 Bcf, including 193.1 Bcf from existing wells.	479.4 Bcf including 193.1 Bcf from existing wells.
Estimated BNGPA-related employment: direct and secondary		2008: 182	2008: 256	2008: 319
BNGPA total personal income 2007–2035	N/A	$155 million	$182.1 million	$210 million
Estimated total Montana Gas Production Tax 2008–2036	N/A	Total: $153.7 M State: $ 71.0 M Phillips Cty: $ 74.8 M Valley Cty: $ 7.5 M	Total: $199.8 M State: $ 92.3 M Phillips Cty: $ 97.1 M Valley Cty: $ 10.3 M	Total: $250.1 M State: $115.6 M Phillips Cty: $121.6 M Valley Cty: $ 12.7 M
Estimated total incremental federal mineral royalties 2008–2036	N/A	No incremental federal mineral royalties would be associated with Alternative A.	Total: $ 62.0 M State: $ 30.7 M Phillips Cty: $ 6.9 M Valley Cty: $ 0.8 M	Total: $ 95.2 M State: $ 35.3 M Phillips Cty: $ 10.6 M Valley Cty: $ 1.23 M
Local government impacts	Comparatively high levels of county road maintenance demand associated with drilling, field development and production activities.	Reduced levels of road maintenance demand associated with lower drilling levels and fewer wells in production. Lower levels of BNGPA-related revenues to offset the costs of road maintenance.	Higher levels of road maintenance demand associated with higher levels of drilling. Higher levels of BNGPA-related revenues to fund road maintenance costs.	Substantially higher levels of road maintenance demand associated with higher levels of drilling and more wells in production. Substantially higher levels of BNGPA-related revenues to offset road maintenance costs.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Effects on social groups	Many people in Phillips and Valley counties benefit directly and indirectly from the employment and tax revenues associated with BNGPA development and production. Two groups who sometimes experience adverse effects are ranchers, farmers, and other surface owners of split-estate lands and recreation visitors who sometimes experience natural-gas development and production-related changes in the recreation setting.	Fewer people would benefit from BNGPA-related employment as a result of lower annual drilling levels and fewer wells in production. Lower BNGPA tax revenues would result in a reduction in service levels or higher taxes for all county residents. Ranchers, farmers and other surface owners of split estate lands would be likely to experience fewer adverse effects. Fewer changes in the recreation setting for recreation visitors to the BNGPA would also occur.	More people would benefit from BNGPA-related employment. Higher BNGPA tax revenues would allow increased service levels or lower taxes for all county residents. Ranchers, farmers and other surface owners of split estate lands would be likely to experience more adverse effects. Changes in the recreation setting would be likely to occur in more areas.	More people would benefit from BNGPA-related employment. Substantially higher BNGPA tax revenues would allow increased service levels or lower taxes for all county residents. Ranchers, farmers and other surface owners of split estate lands would be more likely to experience higher levels of adverse effects. Changes in the recreation setting would be likely to occur in more areas of the BNGPA than under the other two alternatives.
Environmental Justice	In 2000, 18.3% of the population living in Phillips County and 13.5% of the population in Valley County had incomes below the poverty level. These figures compare to a state figure of 14.6%. There are no concentrations of racial minorities in the BNGPA.	No effects	No effects	No effects
Transportation and Access:				
Access	Total of 3,352 miles of highways and roads w/in the BNGPA	Estimated 207.5 miles of new and existing roads and two-tracks required	Estimated 418.75 miles of new and existing roads and two-tracks required	Estimated 636 miles of new and existing roads and two-tracks required

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Drilling, completion and gatherings system construction traffic	Recent traffic levels associated with an average of one drilling rig, one completion crew and one gathering system crew.	Similar levels of daily traffic during drilling; reductions in average annual traffic compared to recent levels as a result of fewer wells being drilled	Temporary increases in traffic during drilling season compared to recent levels resulting from higher drilling and field development levels.	Traffic increases substantially higher than other two alternatives resulting from higher drilling and field development levels.
Production traffic	1,450 wells visited on a schedule ranging from twice weekly to once every two weeks. 25 percent of wells require water hauling, requiring an average of two trips/ week to those wells.	Diminishing levels of well maintenance traffic resulting from reductions in total producing wells in the field. Early increases in produced water disposal-related trips as the 25 percent of wells requiring produced-water disposal age and produce less gas and more water and as new wells using artificial lift come online. Eventual reductions in total produced-water trips as wells requiring produced-water disposal cease production at higher rates than new wells requiring produced-water disposal, and wells using artificial lift come online.	Traffic related to well maintenance would diminish initially, then increase as total producing wells increase to 1,500 by 2022. Maintenance traffic would steadily decline thereafter. Produced-water disposal-related traffic would increase as the number of wells requiring produced-water disposal increase until these wells begin to cease production.	Well maintenance traffic would steadily increase as total wells increase to 2,084 by 2022 and steadily decline thereafter as wells cease production. Produced-water disposal-related traffic would continue to increase after 2022 as the estimated 25 percent of wells requiring produced-water disposal age and produce less gas and more water. This increase would continue until these wells begin to cease production.
Road maintenance	Gas traffic on county roads results in relatively high levels of maintenance demand.	Lower maintenance demand associated with lower drilling levels and fewer wells in production, with the exception of access roads for produced-water disposal facilities.	Higher drilling-related road maintenance demand during first 10 years of drilling. Similar higher levels of production and produced-water disposal-related demand.	Substantially higher levels of drilling, production and produced-water disposal -related road maintenance demand.
Vegetation:				

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Montana Plant Species of Concern	Chaffweed, Dwarf woolly-head, Hot spring phacelia, Long-sheath waterweed, Roundleaf water-hyssop, Scarlet ammannia, Slender-branched popcorn flower, Slender bulrush are known to occur on the project area (Taylor 2006).	No expected impacts to Montana plant species of concern from development activities. Chaffweed, dwarf woolly-heads long-sheathed waterweed, roundleaf water-hyssop, scarlet ammannia, slender-branched popcorn flower, and slender bulrush are associated with aquatic or wetland habitats. Development is not expected to impact any wetlands; therefore, no impacts are expected to occur to these species.	Same as Alternative A.	Same as Alternative A.

Affected Resource & Effect Indicators	Existing Resource Conditions	Alternative A No Federal Action	Alternative B Proposed Action with Additional Mitigation	Alternative C Maximum Development
Proximity to T&E species habitat	There are no known FWS threatened, endangered, proposed, candidate, or experimental plant species documented on the BNGPA (Taylor 2006).	Development activities under Alternative A may affect some threatened, endangered, candidate or proposed species of wildlife, fish, and plants through habitat loss, alteration, and fragmentation, disturbance, displacement, and mortality. However, significant impacts to these species due to development under Alternative A are not expected.	Development activities may affect some threatened, endangered, candidate or proposed species of wildlife, fish, and plants through habitat loss, alteration, and fragmentation, disturbance, displacement, and mortality. However, significant impacts to these species due to development under Alternative B are not expected even though the scope of the impacts is more widespread than Alternative A because of the increased development.	Development activities may affect some threatened, endangered, candidate or proposed species of wildlife, fish, and plants through habitat loss, alteration, and fragmentation, disturbance, displacement, and mortality. Impacts will be greater than both Alternatives A and B because more acres of disturbance will occur under Alternative C. In addition, the scope of the impacts will be more widespread than Alternative A or B due to the proposed increased development. Nevertheless, significant impacts to these species are not expected.
Wildlife:				
Habitat fragmentation and disturbance in the project area	The project area is currently fragmented by many roads, power lines, and existing oil and gas development.	Increased habitat fragmentation and disturbance from 620 wells, 206 miles of existing and proposed two-track roads.	Increased habitat fragmentation and disturbance from 1,255 wells, 420 miles of existing and proposed two-track roads.	Increased habitat fragmentation and disturbance from 1,905 wells, 636 miles of existing and proposed two-track roads.